MANITOBA	Board Order 116/08
THE PUBLIC UTILITIES BOARD ACT	
THE MANITOBA HYDRO ACT	
THE CROWN CORPORATIONS PUBLIC REVIEW AND ACCOUNTABILITY ACT	July 29, 2008
Edited for format and typographical errors only August 25, 2008 Further amended September 4, 2008	

Before: Graham Lane CA, Chair
Robert Mayer Q.C., Vice-Chair
Susan Proven, P.H.Ec., Member

AN ORDER SETTING OUT FURTHER DIRECTIONS, RATIONALE AND BACKGROUND FOR OR RELATED TO THE DECISIONS IN BOARD ORDER 90/08 WITH RESPECT TO AN APPLICATION BY MANITOBA HYDRO FOR INCREASED RATES AND FOR RELATED MATTERS

Table of Contents

Executive Summary 1

1.0 Overview 5
1.1 History 5
1.2 2008 General Rate Application 6
1.3 Previous Board Directives 12
1.4 Board Findings 15
2.0 Operating Results and Financial Projections 23
2.1 MH’s Forecasting Process 23
2.2 Comparison of Actual Operating Results with Prior Forecast 23
2.3 Integrated Financial Forecast (MH07-1) 24
2.4 Board Findings 28
3.0 Forecast Revenues 31
3.1 Domestic Revenues 31
3.2 Extra-Provincial Revenues 31
3.2.1 Energy Available for Export 31
3.2.2 Foreign Exchange 44
3.2.3 Long-Term Export Contracts 45
3.2.4 Inter-Tie Limitations 46
3.2.5 Potential Hydraulic Generation 46
3.2.6 Fuel and Purchase Power 47
3.3 Interveners’ Position 49
3.4 Board Findings 50
4.0 Finance Expense 58
4.1 Changes in Finance Expense 58
4.2 Exposure Management Program and Foreign Exchange 60
4.3 Debt Management 61
4.3.1 Long Term Debt 61
4.3.2 Fixed vs. Floating Rate Debt 62
4.3.3 Sinking Fund Management 64
4.4 Interveners’ Positions 65
4.5 Board Findings 66
5.0 Operating, Maintenance, and Administrative Expenses (OM&A) 70
5.1 General 70
5.2 Staffing Levels 72
5.3 OM&A Costs per Customer 72
5.4 Capitalization of Operating and Administrative Expenditures 74
5.4.1 Current Capitalization Practices 74
5.4.2 Mitigation Costs 77
5.5 Future Changes in Accounting Standards 78
5.5.1 Adoption of International Financial Reporting Standards (IFRS) 78
5.5.2 Future Financial Implications of Adoption of IFRS 79
5.6 OM&A Cost Control Process 83
5.7 Intervener’s Positions 85

Table of Contents

5.8 Board Findings 92
6.0 Depreciation & Amortization 105
6.1 General 105
6.2 Board Findings 106
7.0 Payments to the Province 108
7.1 Interveners' Position 111
7.2 Board Findings 111
8.0 Financial Targets 114
8.1 Background 114
8.2 Debt to Equity 115
8.3 Interest Coverage Ratio 119
8.4 Capital Coverage 120
8.5 Reserves 122
8.6 Interveners' Positions 123
8.7 Board Findings 127
9.0 Capital Expenditures 133
9.1 General 133
9.2 Comparison of CEF03-1 to CEF07-1 134
9.3 New Generation and Major Transmission 134
9.4 Wuskwatim Generating Station (Wuskwatim) 136
9.4.1 General 136
9.4.2 Capital Cost of Project 136
9.4.3 Wuskwatim Power Limited Partnership (WPLP) 137
9.4.4 Wuskwatim Transmission 139
9.4.5 Project Economics 140
9.5 Bipole III 141
9.6 Other Generation 143
9.7 New Head Office 145
9.8 Interveners' Positions 147
9.9 Board Findings 156
10.0 Load Forecasts and Power Resources 170
10.1 Load Forecast 170
10.2 Energy Supply 175
10.2.1 Hydraulic Generation 175
10.2.2 Augmented Flow Programs 176
10.2.3 Thermal Generation 177
10.3 Wind Generation 178
10.4 New Generation and Transmission 180
10.5 Alternative Fuels and Energy Supply 182
10.6 Greenhouse Gas Emissions 183
10.7 Interveners' Positions 184
10.8 Board Findings 186
11.0 Demand Side Management 191
11.1 General 191

Table of Contents

11.2 Program Evaluation ... 191
11.3 Program Costs and Amortization ... 193
11.4 DSM Program Savings ... 194
11.5 City of Winnipeg DSM Program ... 197
11.6 Carbon Trading ... 199
11.7 Low Income DSM Program ... 199
11.8 The Affordable Energy Fund (AEF) ... 202
11.9 Interveners' Positions ... 204
11.10 Board Findings ... 219
12.0 Risk Analysis ... 232
12.1 Drought ... 233
12.2 Other Risks ... 236
12.3 Interveners' Positions ... 239
12.4 Board Findings ... 239
13.0 Cost of Service ... 245
13.1 Background ... 245
13.2 Amended PCOSS-06 ... 246
13.3 Export Costs ... 247
13.4 Embedded Cost Revenue Cost Coverages (RCCs) ... 249
13.4.1 Compliance with Board Order 117/06 ... 251
13.5 PCOSS-08 ... 254
13.5.1 Treatment of Exports Class Cost Allocations ... 254
13.5.2 Review of PCOSS-08 ... 255
13.5.3 Treatment of Exports Class Cost Allocations ... 256
13.6 Marginal Cost Considerations ... 260
13.7 Interveners' Positions ... 262
13.8 Board Findings ... 269
14.0 Rate Design ... 284
14.1 Inverted Rates ... 284
14.2 General Service Small and Medium Classes (GSS and GSM) ... 285
14.3 Area and Roadway Lighting (ARL) ... 287
14.4 Time of Use (TOU) Rates ... 287
14.5 Rebalancing of Demand and Energy Charges ... 288
14.6 The Basic Monthly Charge ... 289
14.7 Diesel Rates ... 290
14.8 Surplus Energy Program (SEP) ... 293
14.9 Curtailable Rate Program (CRP) ... 294
14.10 Limited Use Billing Demand (LUBD) ... 295
14.11 Winter Ratchet ... 296
14.12 Interveners' Positions ... 297
14.13 Board Findings ... 306
15.0 Class Rate Impacts ... 313
15.1 Rate Changes/Rate Impacts ... 313
15.2 Differential Rate Increases ... 315

Table of Contents

15.3 Interveners' Positions 315
16.0 Energy Intensive Industry Rate (EIIR) 317
16.1 Background 317
16.2 MH'S Proposal 318
16.3 MIPUG Motion 319
16.4 MH's Revised Position 320
16.5 Service Extension Policy 320
16.6 Interveners' Positions 321
16.7 Board Findings 327
17.0 Presenters' Positions 334
17.1 Mr. Ciekiewicz 334
17.2 Mr. Forrest 335
17.3 Mr. Rader 336
17.4 Mr. Svidal 337
17.5 Mr. Turner 337
18.0 IT IS THEREFORE RECOMMENDED THAT 340
19.0 IT IS THEREFORE ORDERED THAT: 343

APPENDICES

APPEARANCES .... Appendix A

WITNESSES FOR HYDRO .... Appendix B

INTERVENERS OF RECORD .... Appendix C

INTERVENER WITNESSES .... Appendix D

PRESENTERS .... Appendix E

Executive Summary

Manitoba Hydro's (MH, the Corporation or the Utility) 2008/09 General Rate Application (GRA) was heard by the Public Utilities Board (Board) in the spring of 2008, with Board Order 90/08 released on June 30, 2008 to take effect July 1.

The Board further advised that Order 90/08 would be followed by another Order, one that would provide further direction on a number of other significant matters, and, as well, provide necessary background information and detailed rationale for the rate changes provided by Order 90/08.

Order 90/08 provided certain rate and other directions to the Corporation, as indicated elsewhere in this Order. Order 90/08 is available through the Board's office or by viewing its website, www.pub.gov.mb.ca.

With respect to "further direction", this Order contains various directives to provide new and revised information to the Board in respect of MH's:

- Integrated Financial Forecasts;
- Capital Expenditure Forecasts;
- Load Forecast and Power Resource Plan;
- Export Program;
- International Financial Reporting Standards Implementation;
- Benchmarking Study of Key Performance Metrics;
- Asset Condition Assessment Study;
- Terms of Reference for a Review of MH's Capital Program;
- Quantified Risk Analysis;
- Demand Side Management ("Power Smart" program enhancements);
- Green House Gas Reduction Strategy;
- Low-Income Programs, including a Bill Assistance Program;
- Cost of Service Study (COSS) Revisions;
- Rate Design Revisions;
- MH Diesel Rate Zone; and
- Energy Intensive Industry Rate Proposal.

Executive Summary

Detailed directives and recommendations are found in the last sections of this Order.

For all the reasons referred to in this Order and Order 90/08, the Board approved a 5% across-the-board rate increase as of July 1, 2008 that was larger than the Corporation sought, and, as well, indicated that a further 4% increase may be granted as of April 1, 2009 following the Board's review of additional information requested in this Order. As well, the Board accepted MH's forecast that its net income for the fiscal year 2007/08 will exceed $300 million, and that water conditions into fiscal 2008/09 were excellent, suggesting that another reasonably good net income result may be expected for fiscal 2008/09.

Order 90/08 also advised of the Board's concern with the scale of capital expenditures and new debt now planned over the next 15 years. There is a risk that the Corporation may not be able to meet domestic and export requirements and commitments without having to resort to high-priced imported power or other higher-cost generation in years of lower than median water conditions. The risk of lower than median water conditions, (including a drought), creates a financial risk. The other financial risks include the potential for future interest rate increases, currency fluctuations, capital cost escalations, new accounting standards (IFRS) and other operational factors, some or all of which may well challenge the Corporation's future financial strength.

The Board will direct MH to propose to the Board by January 15, 2009 terms of reference for a regulatory review of the impact that MH's planned Capital program may have on consumer rates. The Board will also direct MH to quantify its risks in an effort to determine the appropriateness of the current financial stability targets.

Executive Summary

The Board also expresses concern with the Corporation's withholding of information related to its export transactions and projections, for stated confidentiality reasons, as that withholding made it difficult if not impossible for the Board to arrive at findings with respect to such matters as to what constitutes the Corporation's marginal cost rate, a final determination of the rules to govern the allocation of costs and revenues to customer classes, the weight to be given to marginal and environmental factors in future differentiation of customer class rates, and, perhaps most importantly, the likelihood of profitability with respect to its export commitments and the risk that these commitments will lead to years of either additional imports of power or thermal generation to avoid supply shortfalls. Accordingly, the Board has requested additional information related to MH's export forecasts.

In this Order, the Board notes that there are approximately 100,000 low-income households that are customers of MH (many, also being customers of Centra Gas), and the particular affordability pressures on these households arising from energy price increases (gasoline, diesel, natural gas and, though much more modest, electricity).

The Board has recently approved issuance of a single bill for consumers of electricity and natural gas and provided MH an ability to maintain natural gas and electricity services, when financial delinquency conditions exist. These efforts avoid disconnections through the availability of an electricity load-limiter and will assist with the health and safety of consumers through the coming winter. However, the Board seeks further actions by the Corporation to address the varied problems of low-income households, problems exacerbated by rising energy costs.

Accordingly, by this Order the Board directs MH to increase its efforts to conserve domestic energy through far more aggressive DSM measures, including those particularly targeted at low-income households lacking the means to invest in energy efficiency measures without assistance from the Corporation.

The reduced consumption benefits expected to arise out of more successful DSM programs will assist low-income households in meeting their utility bills. It will also provide the Corporation with a higher level of supply security to meet future demand requirements.

There is a risk that if natural gas customers move in any significant way to electricity as the sole or supplementary space-heating source for their residences, (a growing risk given recent natural gas commodity price increases and volatility), MH will have less energy to export and may have to import power in some years to meet its commitments. MH’s low rates for all of its customers, excluding “government accounts” in the diesel zone, are maintainable in part due to export profits.

Finally, herein, the Board suggests to government that it consider establishing a separate entity to manage the Corporation’s DSM and low-income initiatives. The Board concludes that MH’s full energies and focus should be placed on the effective implementation of its long-term expansion plans, towards meeting the demand for electricity and natural gas. The Board can envision MH establishing aggressive goals for the reduction of domestic energy consumption for such a new entity to target, together with providing funding to meet those targets. MH will benefit by being able to export the energy that is conserved.

1.0 Overview

1.1 History

Manitoba Hydro's last General Rate Application (GRA) was held in the spring of 2004, following a drought that contributed to a record loss of $428 million for the Corporation's electric operations. That 2004 GRA led to Board Orders 101/04 and 143/04, and those Orders approved a 5% average rate increase, effective August 1, 2004, and two additional average rate increases of 2.25% each, to be effective April 1, 2005 and October 1, 2005 – the latter two increases conditional on MH filing additional information and justification.

Subsequently, by Order 34/05 the Board confirmed the first of the two conditional 2.25% average rate increases, the first one taking effect April 1, 2005. However, due to a reported "dramatic" rebound in water conditions following the drought that contributed to rate increases in Order 101/04, and a favourable financial forecast for MH's fiscal year 2005/06, the Board was advised by MH (on July 5, 2005) that the Corporation would not seek the second conditionally approved rate increase, tentatively scheduled for October 1, 2005.

Water conditions ebb and flow, and subsequently, due to a return to poor water conditions during most of MH's fiscal 2006/07 (not anticipated by MH when it decided to forego the last of the two conditional rate increases), MH applied to the Board to reinstate that foregone average rate increase of 2.25%. After a thorough review of information submitted by MH, and by way of Order 21/07, the Board granted MH's application, effective March 1, 2007, on an interim basis. Final approval of that rate increase was later sought by MH as part of its 2008 GRA, and provided by the Board by way of recent Order 90/08.

1.2 2008 General Rate Application

In the summer of 2007, and pursuant to *The Public Utilities Board Act* and *The Crown Corporation Public Review* and *Accountability Act*, MH applied to the Board for the following:

a) Approval of rate schedules incorporating an across the board 2.9% increase in General Consumers' rates effective April 1, 2008 (with the exception of Area & Roadway Lighting which would receive a 1% increase);

b) Final approval of General Consumers' interim rates approved in Order 21/07 effective March 1, 2007;

c) Surplus Energy Program: immediate interim approval to extend the program (currently set to expire October 31, 2007) to October 31, 2008 together with final approval to extend the program to March 31, 2013;

d) Final approval of all Surplus Energy Program (SEP) interim rate orders as set out in Appendix 10.6 of the GRA;

e) Approval of modifications to the Curtailable Rate Program (CRP) as discussed in Tab 10, Section 10.2 of the Application, and final approval of all interim Curtailable Rate Program orders as set out in Appendix 10.6;

f) Final approval of changes to the Limited Use of Billing Demand Rate (LUBD) as set out in Appendix 10.6;

g) Contingent on final execution of the settlement agreement between Indian and Northern Affairs Canada (INAC), Manitoba Keewatinook Ininew Okimowin (MKO) and Manitoba Hydro, approval of interim *ex parte* Orders related to electricity service in the Diesel Rate Zone as set out in Appendix 10.6; and

1.0 Overview

h) Approval of a new General Service Large rate for new or expanding loads as set out in Tab 10, Section 10.3 of the GRA.

By Order 90/08 and following a public hearing of MH's GRA, the Board established an across-the-board rate increase of 5% effective July 1, 2008 for all MH customers, except for Area and Roadway Lighting customers, whose rates are not to change.

In addition, the Board approved:

a) A further conditional across-the-board general rate increase of 4%, with the exception of Area and Roadway Lighting customers (for whom rates are again not to increase), provisionally to take effect April 1, 2009 (subject to the Board's further review, that, depending on developments, could result in the Board increasing or decreasing the 4% increase conditionally approved);

b) An increase in the Basic Monthly Charge (BMC) for all customers of 5%, as of both July 1, 2008 and April 1, 2009;

c) As indicated above, finalization of Order 21/07 which established an interim rate increase of 2.25% on March 1, 2007;

d) A modest introduction of inverted rates for the "residential" class (SGS), establishing a precedent and indicating an intention to widen the differential in the future;

e) As requested by MH, extension of the Surplus Energy Program (SEP), although only to October 31, 2008 ahead of conclusions yet to be reached and a possible further extension to follow this Order;

f) Modifications to the Curtailable Rate Program, as proposed by MH;

1.0 Overview

g) Changes to the Limited Use of Billing Demand Rate, as proposed by MH; and

h) Final approval for various interim SEP Orders through to the date of the close of the hearing that led to Order 90/08.

Order 90/08 was issued on June 30, 2008, and also indicated that final approval of several Interim *Ex-Parte* Orders related to electricity service in the Diesel Rate Zone would be deferred until final execution of a Settlement Agreement between INAC, MKO and MH had occurred.

The Order also advised MH to re-file, "with any adjustments it may deem appropriate, a revised proposal for a new industrial rate for new and expanding industrial load".

Although the Corporation had sought a 2.9% across-the-board increase, excepting for a proposed 1% increase for Area and Roadway Lighting customers, and had indicated a need for further 2.9% across-the-board increases for each year through to 2017/18, the Board concluded that higher increases were required, at least for 2008 and 2009.

In Order 90/08, the Board noted:

> "With MH's new export and construction commitments and plans, and with the increased risk that MH's Manitoba load forecasts may prove low given the large increase in the price of natural gas over the past year (yet to be fully reflected in natural gas bills), and providing the risk of energy switching, the Board is also concerned with the risk associated with advancing major new generation and transmission projects with industrial rates well below marginal cost."

1.0 Overview

And,

> "While the Board is now providing a 5% increase for 2008 and the prospect for a further 4% April 1, 2009, the latter subject to reconsideration following receipt and review of additional information, the electricity rate increases now set and contemplated pale in comparison to the increases being implemented or planned by other Canadian electricity utilities, and the cost increases now being experienced by consumers, businesses, institutions and governments with respect to other energy sources. "

And,

> "Notwithstanding the Board's appreciation of the negative implications of rate increases for MH's customers, and the Board's particular and on-going concern for low-income households, particularly, in this case, those relying on electricity for space heating, the Board will provide MH with a greater increase than the Corporation sought. This, because of a combination of concerns briefly cited below (to be) elaborate(d) on in more detail in a subsequent Order:
>
> a) In its application, MH advised that its proposed series of 2.9% increases were required to maintain progress towards the eventual attainment of the Corporation's financial targets, primarily the achievement of the long-sought but not achieved target debt to equity ratio of 75:25. MH projected that notwithstanding its forecasts of annual rate increases and the assumption of continuing success with export markets, and taking into account forecast net income for 2007/09 to achieve or exceed $300 million, it still did not expect to achieve the debt:equity financial target of 75:25 by 2017/18 (let alone the current or previous earlier target dates);
>
> b) MH's plans for capital expenditures may involve the expenditure of $18 billion or more over the next 15 years, expenditures predicated in part on what may or may not be overly optimistic export prices – this level of capital expenditure will result in significantly increased debt levels, export commitments and general business risks;
>
> c) MH's reports and evidence of hyper-inflation with respect to construction and commodity costs, which are driving up the Utility's projected costs for new generation and transmission projects and have lowered its estimates of the return to be expected for the first of its new generation projects (Wuskwatim), a project that will likely be followed by further major construction (Pointe du Bois, Bipole III, and the Keeyask and Conawapa generation stations);

d) While the Board shares some Intervener concerns as to an apparent acceleration of MH's OM&A costs (Operating, Maintenance and Administration), which MH attributes to labour shortages as well as increased needs for system maintenance, (both factors cited to be beyond the direct control of the Utility), the Board does not have enough information on whether current and forecast OM&A expenditures are fully supported, since no formal and in-depth benchmarking has yet been undertaken;

e) The approaching adoption of International Financial Reporting Standards (IFRS), which will form the new Canadian Generally Accepted Accounting Principles (GAAP), with potentially materially significant and negative impacts for the Corporation's current forecasts of annual net income results through 2017/18;

f) There has been a significant increase in the value of the Canadian dollar relative to American currency, and it has had the effect of reducing the value of electricity exports as expressed in Canadian dollars. The Canadian dollar has climbed from just above 60 cents U.S. dollar (USD) to near parity with the U.S. currency. With MISO imports (MH's exports) priced in USD, this has affected MH's export revenues. While MH forecasts the Canadian dollar falling back about 15 cents from its current level, the Board is not confident with that forecast, and if near parity remains MH's export price forecasts are in jeopardy;

g) There appears to be a growing disconnect between electricity prices obtained from American markets and natural gas prices (in the past, when natural gas prices rose, the assumption and general experience was that MH's export prices rose as well); and

h) Continuing business risks related to interest rates (now at recent historic lows), the risk of further currency fluctuations, drought, inflation, market access problems, and other concerns: "

"Interest rates are at very low levels in both an absolute and relative to inflation sense – the current prime rate of the Bank of Canada is approximately only one percentage point higher than the current national rate of inflation – and with hyper-inflation present with respect to commodities (including energy) and processed products such as chemicals, steel and concrete, the Board is concerned that interest rates will increase at some point during MH's expansion phase, placing increased pressure on the cost of the Corporation's operations."

And,

> "MH has benefited from 12 of the last 16 years being of above or near median water flows; statistically, poorer water conditions can be expected to occur at some point in the future and a drought, which has been experienced regularly through the Corporation's history, could have a devastating impact on MH's financial situation, as it recently did in fiscal 2003/04."

And,

> "MH's export market is primarily American utilities within the MISO market, and transmission lines on both sides of the border are required to transport the power to MH's export customers and carry power back to Manitoba when imports are required, and there are risks involved with reliance on a significantly predominant market. While a national east-west grid remains a worthy objective, there is no present indication that MH's Canadian provincial customer list, particularly from a volume perspective, can be assured to strongly develop."

The Board concluded its overview of the Corporation's risks by stating in Order 90/08 that it "is focused on the risks that lie ahead and determined to ensure as reasonably as possible that MH has the financial strength to meet the risks".

> "The rate changes and comments of present and future risks associated with this Order should not be perceived as a challenge to the perspective that MH remains a tremendous asset for Manitoba, and that the Corporation continues to have and represent large growth opportunities. Even with the rate increases announced and forecast herein, Manitobans should continue to benefit from some of the lowest electricity rates in North America.
>
> The Board also finds it important to recognize a present and growing disconnect between relatively stable and low electricity rates (set by a regulatory body with particular attention to historic costs) and other competing energy prices, the latter set by largely unregulated market forces little affected by the actual cost of production and distribution.
>
> With respect to MH, while the costs of generation, transmission and distribution assets acquired decades ago have allowed for residential rates of 6 cents per kilowatt hour (kW.h) and 3.2 cents for major industry, the new generating stations and transmission facilities will demand much higher rates simply to break even, let alone produce the net income required to allow MH to move forward supported by a reasonable capital structure.

> As a comparison to electricity rates … Combining actual and projected natural gas bill increases for 2008, it would not be surprising if natural gas customers end up paying 30% more for their natural gas this winter as opposed to the last. With respect to fuel oil, propane, gasoline and diesel, increases experienced are even more severe.
>
> In 1999, when MH purchased Centra Gas, space heating by natural gas … could be expected to come at half or less than half the cost of an electrically-heated home; this is no longer the case. (Now) … space heating by electricity (is) cheaper than by natural gas for all residences other than those that heat by way of a high-efficiency gas furnace. If the trend continues more and more new and existing residences may select or convert to electric heating, driving up domestic electricity load and limiting export sales and profits."

The Board noted that Order 90/08 would be followed by a more detailed Order that would provide further direction, necessary background information and detailed rationale for the rate changes of Order 90/08. The Board also noted that the subsequent Order, which is this Order:

> "… will also summarize and encapsulate the positions of Interveners and MH, the comments of presenters, and the evidence of witnesses all appearing before the Board at the public hearing of MH's GRA, a hearing held over 19 days in the Board's offices in the months of March, April and May 2008."

1.3 Previous Board Directives

In addition to MH's specific requests for Board approval in the Utility's GRA, MH reported on the status of various responses to previous Board Directives that were issued in Orders:

117/06 - A review of Manitoba Hydro's Cost of Service Study Methodology and other matters.

Order 117/06 followed a comprehensive public hearing which reviewed in depth MH's Cost of Service Study Methodology, and provided various directives to modify and refine the methodologies to be used in subsequent Cost of Services Studies. In the recent GRA, the Board and Interveners had the opportunity to consider those modifications and refinements in MH's Prospective Cost of Service Study - 08 (PCOSS -08).

173/06 – Application by Manitoba Hydro for the extension of the approval of the Surplus Energy Program (SEP).

By 173/06, the Board approved the extension of SEP to the earlier of October 31, 2007 or a further application by MH, with the expectation that the SEP would be included for review in MH's 2008 GRA.

176/06 - An Interim ex parte Application by Manitoba Hydro for an Order approving new electricity rates in four communities served by diesel generation, to be effective January 1, 2007.

This was the fourth Order, in a series of Orders (17/04; 45/04; 159/04; and 176/06) that adjusted rates, each provided on an interim basis, in the four communities that Manitoba Hydro services by diesel generated electricity. The communities are:

Barrenlands First Nation (also known as Brochet)

Northlands Dene First Nation (also know as Lac Brochet)

Syisi Dene First Nation (also known as Tadoule Lake)

Shamattawa First Nation (also known as Shamattawa)

The interim rates approved in Order 176/06 (as well as the other interim orders) were predicated on MH filing an Application to finalize all outstanding Diesel Zone Interim Orders, as soon as the Settlement Agreement among MH, MKO, and INAC has been fully executed.

20/07 - Manitoba Hydro - Interim Rate Increase effective March 1, 2007.

1.0 Overview

This Order approved, on an interim basis, the 2.25% average rate increase that MH, in the most recent GRA sought to confirm, and which the Board has confirmed by way of Order 90/08.

By this Order, the Board also comments on MH’s responses to previous directives and provides additional directives for the attention of the Utility.

1.4 Board Findings

As was the case with Order 90/08, this Order addresses many complex issues and provides detailed analysis, discussion and decisions (in other sections of this Order) in support of not only the directed rate approvals provided by Order 90/08 but also with respect to other matters deferred to this Order.

For all of the reasons set out both above and in the Board's Findings sections included herein, the fiscal health of MH, along with the affordability of energy for low-income households, remain the Board's greatest concerns. While the Board's concern over MH's financial situation lies largely with the $18 billion of capital expenditures likely to lie ahead, and the debt expected to be incurred to fund those expenditures, the Board's concern for low-income households is with their ability to pay seemingly "ever-increasing" energy bills (not just electricity, but also natural gas, gasoline, diesel, fuel oil and propane).

The Board also notes elsewhere in this Order, findings related to MH's OM&A expenses and the Corporation's efforts at expense control, and observes that the unprecedented planned increase in such capital expenditures are beyond the Board's statutory jurisdiction to approve or deny. Nonetheless, the impact on finance and depreciation expense arising from capital expenditures, along with the risks ever-present with a Corporation dependent in large part on weather and other matters not within its control – general inflation, interest rates, currency fluctuations, represent the largest component of the upward pressure on consumer rates.

In considering its directions and comments, the Board is mindful of past directions from the Manitoba Court of Appeal:

1.0 Overview

> "The Board's function is not only to protect consumers from unreasonable charges, but also to ensure the fiscal health of the corporation and fairness between different classes of consumer." [1]

1. Coalition of Manitoba Motorcycle Groups Inc. v. Manitoba (Public Utilities Board) [1995] M.J. No. 301 (C.A.).

Attention to the fiscal health of MH (as one factor in the Board's determination of the public interest), has been supported by the Manitoba Court of Appeal.

The intent of the legislation is for the Board to approve fair rates, taking into account such considerations as cost and policy, or other factors as the Board may deem appropriate. Rate approval involves balancing the interests of multiple consumer groups (residential, commercial, institutional and industrial) with those of the utility. In the end, the long-term interests of consumers and the utility should coincide.

The Board's decision in Order 90/08 to build retained earnings more rapidly than MH proposed, in order to better protect the utility and consumers from the potentially devastating financial impact of future drought and other identified risks, clearly meets the intent of the legislation and is within the jurisdiction afforded to the Board in s. 26 of *The Crown Corporations Public Review and Accountability Act*.

It should be clear for the reasons cited herein that the Board understood its role in this regard.

> "The (Board) has two primary concerns when dealing with a rate application; the interests of the utility's ratepayers and the financial health of the utility. Together, and in the broadest interpretation, these interests represent the general public interest." [2]

2 Consumers' Association of Canada (Man.) Inc. et al v. Manitoba Hydro Electric Board, 2005 MBCA 55

In arriving at its decision to grant MH rate increases as of July 1, 2008 and April 1, 2009 (the latter conditional), the Board took into account recent financial results and forecasts which, particularly if the forecasts are met, will contribute in a meaningful way to improving MH's financial strength in the near term.

Financial results for fiscal 2007 were $13 million better than projected and the current projection of $300 million (or more) of net income for fiscal 2007/08 represents a gain of at least $96 million over what had been anticipated given median water flows. The Board also understands that energy in storage (water in the reservoirs) was at record or near record levels going into 2008/09 and that water flow conditions remain favourable, both factors suggesting that the current forecasted net income of $156 million for 2008/09, (which was again based on median water flows), may be exceeded.

If these projections prove out, MH will have enjoyed 14 of the last 18 years of above or near median water flows. While such a result would be very good news indeed, history has a habit of repeating itself, particularly when it comes to weather, and years of water flow better than median may very likely be followed by years of below median water flows.

Then, there are the significant concerns expressed over the forecasted increase in capital spending, concerns expressed not only by the Board, but also MIPUG, the Coalition and MKO. The concern is of particular importance as the capital program increases now forecast are, at least initially, driven by export sales commitments.

Interveners suggest a capital justification hearing or, at least, a public dialogue on the appropriateness of the capital program, which brings risks as well as opportunities. The Board shares this view.

And, MH's intended capital program, unprecedented in the Corporation's history, and supported in large part by the expectation of large export sales, also has risks, the larger the commitments the larger the risks.

1.0 Overview

The Board would be remiss if it did not acknowledge that a primary driver of the Board's decision to increase 2008 rates by 5%, 2.1% more than MH sought, was the Board's perspective that attention should be paid to not only reaching but also maintaining the 75:25 debt to equity financial target.

It is not as if MH is already at its 75:25 debt:equity target, or that MH has projected to the Board that it expects to reach and maintain that target. In fact, due to the planned acceleration in capital spending, driven primarily by export considerations, the Corporation is not expected to meet its 75:25 debt to equity ratio target during the current forecast period, which extends to 2017/18, and those forecasts already assume annual average rate increases of about 3% each year.

In addition, major new contracts are being contemplated for export sales that will require new generation and transmission facilities costing over $6 billion, costs which have not yet been incorporated in the forecasts of the Corporation.

That said, the Board was reluctant to raise MH's rates by more than the Corporation sought. The Board is well aware that Manitoba's consumers are facing extraordinary increases in the cost of living caused largely by increases in petroleum prices. High petroleum costs are also translating into higher costs for staples: food, tires, gasoline and diesel prices, and heating oil, propane and natural gas heating costs.

For the Board, in meeting its mandate to serve the public interest, that interest includes the financial health of the Utility. A major capital program, combined with water, interest rate, accounting and currency risks, warrants larger rate increases than those sought by the Corporation, in order to improve the Utility's financial resilience.

1.0 Overview

The Board is encouraged by improved financial projections for fiscal 2008, noting that MH has indicated its financial results is likely to exceed $300 million, an improvement from the $264 million reflected in its previous forecast. The Board further notes that MH has indicated near record level energy in storage and favourable water flows at the outset of fiscal 2009, which bodes well for MH meeting if not exceeding its fiscal 2009 forecasted net income of $156 million. Such improved financial results would also assist in enhancing the financial strength of MH.

The Board notes that the improvement is very much linked to higher volumes of hydraulic generation and is not reflective of increasing export prices or demonstrated cost reductions from previous forecasts.

While MH's fiscal health has significantly improved from the financial impact of the 2003/04 drought, where the loss incurred was the largest in the Utility's history, a future drought, one that could extend over several years, would result in larger generation reductions than the 2003/04 drought brought about, and would result in greater financial loss.

The Board is of the view that further improving the financial strength of MH, regardless of current improved results, is important to the future of the Utility, and that Manitobans, already enjoying electricity rates well below the average found on the continent, and cognizant of the rapid and hyper-inflationary increases for commodities generally (and energy in particular), will accept that an increase of 5% is now necessary.

MH financial strength has a significant influence on the finances of the Province, and MH's financial strength is a major consideration in the evaluation of the credit rating of the Province. In fact, the interest rates MH now enjoys are far below what would be required if not for the guarantee of the Province. The Board further notes that MH has also indicated that the Corporations' debt to equity ratio would have to be similar to that of privately-owned utilities (i.e. 60:40) in order to borrow at rates comparable to the cost of funds received through the Province, without the Province's guarantee.

Any downward adjustment in the credit rating of the Province would likely result in higher borrowing costs for MH as well as the Province, and serve as a double blow against the interests of consumers and industry.

MH rates should gradually begin to recognize the rates required to support new generation and transmission. Given the economic benefits that flow to the current generation of Manitobans as a result of an extensive capital expenditure program and the maintenance of an efficient and effective electrical grid, it seems reasonable that (to some limited extent) the current generation should shoulder some of the rate burden possibly destined for future generations

Leaving aside the weather, maintenance and economic risks that the Corporation faces, there is also the matter of the adoption of IFRS and the consequences for the Corporation once IFRS becomes GAAP. The Board shares the concern expressed by MH's Vice President of Finance and Chief Financial Officer when he testified that IFRS accounting could reduce the Corporation's annual average forecast of net income through to 2017/18 by as much as $120 million a year.

In fact, the Board needs to have MH's risks fully quantified to provide guidance on future rate requirements. And, while revenue alone will not be sufficient to support projected capital spending, MH needs sustained and repeated annual rate increases to support its financial position. Furthermore, the Board is concerned that the recently-announced new export contracts have not yet been reflected in the Corporation's Capital and Resource Requirements analysis, and the Board needs to see an updated Integrated Financial Forecast (IFF), Capital

Expenditure Forecast (CEF), Load Forecast & Power Resource Plan going out to 2028, this beyond the regular forecast period of 2018 to better gauge fully what lies ahead for ratepayers.

For the reasons cited above, and given the overall situation and prospects for additional rate increases as well as borrowings in the future, the Board confirmed as final, by way of Order 90/08, the interim rate increase of 2.25% granted March 1, 2007 on an interim basis. The Board believes that the initial interim increase, which took effect in fiscal 2007/08, was an integral part of the improved financial results for the year just completed.

In light of all the pressures on MH, it is acutely important that the financial strength of MH be improved. In the past MH has been striving to achieve a debt to equity target of 75:25. Although the target was deferred to 2011/12, it now appears that it will not be achieved and held to until well beyond 2017/18.

MH is evaluated by credit rating agencies that are interested in seeing MH making progress toward its financial targets. It is vital that progress continues to be made to ensure no negative implications for the credit rating of the Province. A strong credit rating results in access to capital at reasonable costs. Any deterioration in the credit rating of the Province attributable to MH would likely lead to higher borrowing costs for both the Province and MH.

All this said, the Board does not believe ratepayers alone should shoulder the obligation to maintain the utility's financial health. The Board expects the Corporation to demonstrate and provide evidence of tangible results in the management of OM&A costs and the Capital program, as well as addressing other issues and meeting directives discussed in detail in other sections of this Order.

1.0 Overview

Approval of the conditional 4% increase now slated for April 1, 2009 is dependent on MH addressing (to the Board's satisfaction) certain directives set out in this Order and filing additional financial information to allow the Board to assess whether the conditional increase is justified. The Board will direct MH to file (before January 15, 2009), supporting information for Board review of the 4% April 1, 2009 conditional increase. In addition to the information to be filed with the Board by that date, MH is to include:

a) first, second and third quarter 2008/09 unaudited financial results and statements; and

b) an updated forecast of net income for 2008/09, reflecting existing water energy in storage conditions.

2.0 Operating Results and Financial Projections

2.1 MH's Forecasting Process

MH utilizes four main forecasting tools:

a) The integrated financial forecast (IFF) projects MH's financial results over an 11 year period and includes an income statement, balance sheet and statement of cash flow.

b) The System Load Forecast projects energy and capacity requirements for electricity in Manitoba over the next 20 years.

c) The Power Resource Plan forecasts MH's supply capabilities under dependable flow conditions.

c) The Capital Expenditure Forecast (CEF) includes the planned capital expenditures for a 10 year period including safety requirements, supply side enhancements major generation and transmission projects and investments in administrative assets.

2.2 Comparison of Actual Operating Results with Prior Forecast

The IFF reviewed at the last GRA was IFF03-1, presented at the Board's 2004 hearing of MH's GRA. At that time, MH had just endured a severe drought and was forecasting a loss of $355 million for fiscal 2004. At the 2004 hearing MH provided an update to the Board indicating that the forecasted drought loss would be greater than that reflected in IFF03-1, projecting a loss falling between $400 million and $430 million, which ultimately settled at $428 million.

As directed in Order 101/04, MH filed IFF MH04-1 to justify implementation of the first 2.25% conditional increase, which was granted by the Board effective April 1, 2005.

As a result of the increases granted by the Board, more favourable water levels in fiscal 2005, and higher export sales in fiscal 2006, MH's financial position improved in the order of $130 million over the forecasts of IFF03-1 and IFF04-1.

The favourable water conditions of 2005 and 2006 reversed in fiscal 2007. In January 2007, MH sought from the Board a 2.25% rate increase. In support of its application, MH filed IFF MH06-2, which forecast a $108 million net income for fiscal 2006/07. The Board granted that increase on an interim basis by Order 21/07, and it took effect March 1, 2007.

2.3 Integrated Financial Forecast (MH07-1)

At the most recent GRA, MH filed its most current IFF (IFF MH 07-1) for its electricity operations, as well as its most current capital expenditure forecast (CEF 07-1), both for the eleven-year period 2008 to 2018. The IFF provides an indication of MH's view of its long-term financial direction in both absolute terms and as to achieving its financial targets, and is for use in future planning. MH's operating results since its 2004 GRA are compared to actual and prior forecasts as follows:

2.0 Operating Results and Financial Projections

Statement of Operations & Retained Earnings ($ Millions)	**Actual**				**IFF07-1**	
Fiscal Year	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**
Revenue						
Domestic	936	954	1001	1,040	1,079	1,108
Requested Rate Increase	-	-	-	-	-	31
Export	351	554	827	592	582	468
Total Revenue	1,287	1,508	1,828	1,632	1,661	1,607
Expenses						
Finance	455	473	473	472	404	426
Depreciation	276	291	303	314	332	347
Operations & administrative	293	308	322	332	351	360
Water Rentals	71	111	131	112	121	112
Tax expense	51	52	54	55	57	64
Fuel & power purchases	569	135	125	226	132	143
Total Expenses	1,715	1,370	1,408	1,511	1,397	1,452
Net income [IFF 07 - 1]	(428)	138	420	121	264	155
Compared to Prior Forecasts						
Net income (loss) [IFF03-1]	(355)					
[IFF04-1]	-	147	208			
[IFF06-2]	-	-	-	108	174	127
Net income difference	(73)	(9)	212	13	90	28
Retained earnings Actual/IFF 07-1	707	845	1,265	1,386	1,650	1,805
Retained earnings from above IFF	759	854	1,061	1,398	1,572	1,699
Cumulative difference	(52)	(9)	204 -	12	78	106

Domestic electricity revenues are forecast to increase with load growth (usage) and approved rate increases. Export revenue forecasts are based on volumes and market prices, the former limited by water conditions and transmission capacity, the latter on demand and supply conditions in the MISO market (the marginal cost of the next unit of production).

MH's projected net income for the three-year period 2006/07 to 2008/09 is projected to be $131 million higher in IFF 07-1 than the aggregate result for that period forecast in the earlier IFF 06-2 forecast. Incorporating the changes from prior IFF's, as discussed above, MH's net income for the five year period 2003/04 to 2008/09 is now forecast to be over $261 million higher than was the case with the previous forecast.

IFF MH07-1 reflects both the interim increase of 2.25% granted March 1, 2007, finalized by Order 90/08, and MH's requested 2.9% increase as of April 1, 2008, varied to 5% from July 1, 2008 by Order 90/08. The forecast also assumes annual increases of 2.9% for the years 2009/10 through 2017/18. While the Board has already indicated consideration of a 4% increase for 2009/10, later rate forecasts will be the subject of future applications and processes.

MH's decision to file the most current GRA was based on IFF MH06-4, a forecast which projected net income for fiscal 2007/08 to be $249 million, with a further $163 million for fiscal 2008/09. During the GRA, MH provided an oral update to IFF07-1, suggesting that net income for fiscal 2007/08 will be higher by at least a further $36 million. Relative to IFF MH06-4, net income for 2007/08 was then expected to be at least $51 million higher than that forecast. The most recent anticipated improved operating results for fiscal 2007/08 are not reflected in IFF MH07-1, and despite the oral update, MH did not revise its request for a 2.9% increase as of April 1, 2008.

MH advised that its actual financial results for fiscal 2007/08 would not be made available to the Board until mid-June 2008, and, then, only in confidence pursuant to normal legislative reporting requirements.

MH's operating results and forecasts compared to the forecast of the 2004 GRA were as follows:

2.0 Operating Results and Financial Projections

Statement of Operations & Retained Earnings ($ Millions)	Actual				IFF07-1		
Fiscal Year	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**Total 2004-2009**
Revenue							
Domestic	936	933	929	965	985	1,014	
Estimated PUB Approved Increases	-	21	72	75	94	94	356
Export	351	554	827	592	582	468	
Total Revenue	1,287	1,508	1,828	1,632	1,661	1,576	
Expenses	1,715	1,370	1,408	1,511	1,397	1,452	
Net income (loss) [IFF 07 - 1]	(428)	138	420	121	264	124	
Compared to 2004 GRA Forecast							
Net income (loss) [IFF03-1]	(355)	40	31	30	17	29	
Net income difference	(73)	98	389	91	247	95	847
Retained earnings Actual/IFF 07-1	707	845	1,265	1,386	1,650	1,774	
Retained earnings IFF03-1	759	799	830	860	877	906	
Cumulative Retained Earnings difference 2004 GRA vs. 2008 GRA	(52)	46	435	526	773	868	

Overall, since the 2004 GRA, MH's net income has been $847 million higher than that forecast at that time. The increase in net income is due in part to improved water conditions, conditions better than the median results expected, which led to higher than forecast exports. As well, rate increases approved by the Board since the 2004 GRA have contributed approximately $350 million in additional revenue for the fiscal years 2004/05 through 2008/09.

2.4 Board Findings

There has been an improvement in MH's financial results from that forecast in IFF03-1 at the 2004 GRA, notwithstanding the severe drought experienced in 2003/04. The Board further notes that, aided by much better water conditions than expected, record export sales (provided not only by the water conditions but also by the prices obtained following hurricanes Katrina and Rita in the summer of 2005), along with rate increases, brought in approximately $350 million in revenue, and further contributed to the improved results.

The Board would have expected such additional revenue to have significantly improved the financial strength of the utility, as displayed in its meeting its financial targets, compared with the original forecast. Yet it didn't, and the Board is concerned that MH is still not forecasting to achieve its debt:equity target within its forecast period, not by 2011/12 or throughout the entire 11 year forecast ending in 2017/18.

While the forecasts through to 2018 assume annual rate increases of 2.9%, and annual profits that appear to be very large, particularly to a province accustomed to narrow government budget surpluses and relatively modest returns from government enterprises, the Board not only notes the magnitude of the growing asset base on which these earnings are forecast to occur (restrained as it is by asset costs incurred decades ago at very much lower prices than replacement costs), the Board continues to question the "solidity" of the results and forecasts.

While MH advised that its fiscal 2008 net income would exceed $300 million, due to higher than initially forecast water flows, risks abound with respect to MH's longer–term forecasts, particularly:

a) A decline in export contract sales, trending down to 145 GW.h by 2017/18 in the absence of new contracts [the recently announced sales to Minnesota and Wisconsin, if consummated, will reduce this risk];

b) The limitations of the Corporation's ability to export until Conawapa, Keeyask and other Generating resources, including wind, come on line, in conjunction with the expected restrictions on the Brandon thermal plant commencing in 2009;

c) MH's future domestic load growth forecast may prove low, with the risk of consumers switching to electricity from space heating by natural gas, which is now more expensive than electricity except in the case of high efficiency furnaces;

d) MH's Canadian dollar exchange rate forecast assumptions;

e) MH's future export price forecasts are predicated on imposition of a carbon tax, yet there is no current certainty of such a tax being implemented and having a materially beneficial effect within the immediate horizon of IFF07-1;

f) Escalation in construction cost inflation over the past five years. Increases in commodity costs (iron, steel, concrete, copper and nickel for example) have been sharp and sustained;

i) Based on recent experience, current capital expenditure forecasts related to future construction may prove to be low, and actual costs may exceed the forecasts;

j) Recent or good water flow levels suggest an increased risk of a severe drought during a time when MH's capital expansion plans are significant; and

k) The required adoption of IFRS as of MH’s 2012 fiscal year (with MH’s 2011 fiscal year financial statements required to be IFRS based for comparison purposes).

A further discussion of each of these risk factors is provided later in this Order.

3.0 Forecast Revenues

3.1 Domestic Revenues

In IFF 07-1, MH forecast that at pre-Order 90/08 rates domestic revenues would increase from $1.057 billion (for fiscal 2008) to $1.258 billion by fiscal 2018, a projected increase of $201 million. Additional revenue forecast to arise from assumed 2.9% annual rate increases for each year from fiscal 2008/09 on to 2017/18 was projected to contribute a further $395 million to MH's forecast revenue growth, with total revenue forecast for fiscal 2017/18 to be $1.653 billion.

The forecast of $200 million in additional domestic revenue at pre-Order 90/08 rates reflects projected net load growth of about 3,500 GW.h over the ten-year period. Of this, 2,200 GW.h, almost entirely expected to occur in the first three years of the forecast, relates to projected new industrial load. To the Board, it appears that MH has assumed that a new Energy Intensive Industry Rate, as initially proposed by MH to take effect in 2008/09, will be applied to almost all of the industrial load growth forecast in IFF 07-1.

3.2 Extra-Provincial Revenues

3.2.1 Energy Available for Export

MH's hydraulic generating resources, supplemented by thermal and wind generation as well as imports (the latter source when required) allow for projected annual exports of energy ranging from about 4,000 GW.h to 15,000 GW.h per year, actual volumes to be affected by water flows and domestic load.

Typically, MH has forecast exports (total supply minus domestic load) in each current year on the basis of known water supply conditions. For the second year of a multi-year forecast, MH utilizes known end of Year 1 conditions plus an assumption of median water flow for the second year. The third year forecast, and each year thereafter, uses the long-term mean flow conditions (basically the average experience of the past).

In IFF 07-1 export sales are forecast at:

MH Forecasted Export Sales

Fiscal Year	GW.h	$ million
2008	11,152*	$582 *
2009	7,549	$468
2010	6,608	$416

*Note**

MH has indicated that exports for fiscal 2007/08 will be significantly higher than its forecast due to higher than forecast water flow.

Also, exports assume that in addition to hydraulic generation, MH will have other resources, as follows:

MH Forecasted Power Resources (GW.h)

Fiscal Year	Thermal Generation GW.h	Imports GW.h	Wind Purchase GW.h	Total GW.h
2008	351	880	320	1,551
2009	203	1,194	320	1,717
2010	928	1,948	320	3,194

The export forecast for fiscal 2008/09 of 7,549 GW.h compares to total exports and average export prices in 2005, 2006, and 2007, as shown below:

MH Average Export Prices (2005 to 2007)

Year	2005	2006	2007
Export Revenue ($ millions)	$554	$827	$592
Export Power (GW.h)	10,780	16,034	11,717
Average Price (¢ per kW.h)	5.13 ¢	5.16 ¢	5.05 ¢

When river flows are above average, MH's hydraulic generation resources supply the export of energy surplus to domestic needs. MH provides "clean" energy at competitive prices into American, Ontario and Saskatchewan energy markets.

The following table illustrates the historical average annual export prices achieved by MH, in comparison to natural gas supply prices:

Average Annual Export Prices/Natural Gas Supply Prices

Fiscal Year	U.S. and Canadian Exports (Canadian ¢/kW.h)	Natural Gas Supply (USD/MMBtu)
1993	1.58	1.91
1994	2.54	2.25
1995	2.69	1.75
1996	2.54	1.95
1997	2.33	2.61
1998	2.16	2.41
1999	2.82	2.00
2000	3.43	2.46
2001	3.91	5.03
2002	4.90	3.08
2003	4.89	4.29
2004	4.99	5.16
2005	5.53	6.28
2006	5.19	9.29
2007	5.08	6.67
2008	5.00 (est.)	8.00 (est.)

Until 2004/05, the Corporation's average electricity export prices tended to track and move in tandem with changes in natural gas prices. However, from 2006 average export prices appear to have plateaued at just above 5.0¢/kW.h. This has occurred despite currently-high natural gas prices.

In 2007/08, a dramatic shift in the Canadian/U.S. exchange rate contributed to average export prices moving below 4¢/kW.h for opportunity energy sales, and below 5.5¢/kW.h for firm (dependable) energy contract sales. As illustrated in the following table, the recent price drop appears to be largely related to changes in the exchange rate. However, and as well, the Board notes no indication that prices for dependable energy in USD terms have escalated with inflation.

NEB Average Export Price Data* (converted to U.S. ¢/kW.h)

Date	Exchange Rate (CDN $)	Opportunity Export		Dependable Export		Imports	
		¢/kW.h (CDN)	¢/kW.h (US)	¢/kW.h (CDN)	¢/kW.h (US)	¢/kW.h (CDN)	¢/kW.h (US)
2006							
November	1.14	6.3	5.55	6.1	5.35	5.6	4.95
December	1.16	6.5	5.6	6.4	5.5	5.9	5.1
2007							
January	1.18	6.0	5.1	6.0	5.1	5.6	4.8
February	1.18	8.7	7.4	6.2	5.3	6.0	5.1
March	1.18	6.6	5.6	6.1	5.2	4.0	3.4
April	1.14	6.8	6.0	6.0	5.3	4.0	3.5
May	1.10	5.0	4.55	6.0	5.45	2.0	1.8
June	1.06	4.5	4.25	5.5	5.2	6.0	5.65
July	1.05	4.0	3.8	5.2	4.95	9.5	9.0
August	1.05	4.0	3.8	4.8	4.55	7.8	7.4
September	1.05	3.8	3.7	5.0	4.9	8.2	7.8
October	0.98	3.6	3.7	4.8	4.9	9.8	9.6
November	0.97	4.0	3.9	5.8	6.0	10.0	9.7
December	1.00	6.2	6.2	5.4	5.4	2.5	2.5
2008							
January	1.05	5.2	5.2	5.3	5.3	6.1	6.1
February	1.00						
March	0.98						

Firm dependable export contracts reflect the '5 x 16 peak period' (five days/week and 16 hours/day), with most of MH's exported energy being sold being on-peak and displacing natural gas electricity generation. As previously indicated, export prices in USD terms have, at least until recently, tended to reflect natural gas supply costs.

Current long term export contracts assure MH of export sales of about 2,500 GW.h/year at prices above 5¢/kW.h (5.5¢/kW.h on average for fiscal 2007/08). Other active contracts are shorter-term market based arrangements, and, for them, prices are now running below 4¢/kW.h for sales volumes of 1,500 GW.h/year.

Overall, the above contracts engaged about 50% of tie-line capacity during the '5 x 16 peak period' in 2007/08.

Interruptible opportunity export sales are broad-time spectrum sales that attempt to capture the remainder of on-peak tie-line availability, and relying on shoulder and off-peak periods to maximize total electrical energy sales. These off-peak sales in fiscal 2007/08 accounted for an additional 8,000 GW.h in 2007/08, and brought an average price somewhat below 5.0¢/kW.h.

Contract and other energy sales are as follows:

Export Revenue in CDN ($000)									
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Date	EPE-33	EPE-34	EPE-35	EPE-144	EPE-155	EPE-207	EPE-224	EPE-268	EPE-269
April/07	0	0	0	1,468	1,109	2,303	9,376	1,152	24,811
May/07	0	0	3,857	1,461	1,177	2,451	9.867	0	31,331
June/07	0	1,246	4,101	1,263	1,097	0	9,195	0	33,861
July/07	2,439	1,829	4,930	1,400	1,136	0	9,576	0	33,768
August/07	2,648	1,986	4,836	1,445	1,155	0	9,745	0	34,890
September/07	549	412	2,807	1,206	994	0	8,435	0	22, 852
CDN $MWh									
Date	EPE-33	EPE-34	EPE-35	EPE-144	EPE-155	EPE-207	EPE-224	EPE-268	EPE-269
April/07				87.65	55.03	68.64	56.07	68.57	73.20
May/07			60.86	79.81	53.29	67.31	54.10		48.55
June/07		36.22	53.19	80.34	54.43		55.73		43.35
July/07	36.30	36.30	54.38	79.84	53.78		54.65		39.45
August/07	35.98	35.98	50.08	78.81	52.74		53.41		38.31
September/07	33.93	33.93	37.44	75.39	51.80		52.87		32.94

The above table illustrates MH’s current firm export sales contracts (the first eight columns) and MH’s current opportunity sales (EPE-269). As the Canadian dollar strengthened, export prices in Canadian currency declined: 35% of the export prices realized by MH were in the 3.5 to 5.0¢/kW.h range; 60% of export sales were at prices between 5.0 and 5.5¢/kW.h; and export prices above 7.0¢/kW.h were realized in only approximately 5% of the sales.

The above low pricing situation may not prevail as new export agreements come into play, with potentially-higher environmental premiums. Opportunity sales outside the agreements currently being negotiated are averaging about 5¢/kW.h, as opposed to the 6-7¢/kW.h that MH had previously anticipated.

MH's forecasts of average export prices employed for the second year of each IFF compare favourably with actual prices in fiscal 2004 and fiscal 2005, though at that time, natural gas prices had soared following hurricanes Katrina and Rita and the connection between natural gas prices and MH's export sales were stronger. However, in the last three years MH has over estimated the average CDN $ export price.

Fiscal Year	IFF-2nd Year Price Forecast	Actual Results
2006	6.2¢/kW.h	5.2¢/kW.h
2007	7.5¢/kW.h	5.1¢/kW.h
2008	7.1¢/kW.h[1]	5.0¢/kW.h (est.)

[1] From PCOSS 07/08

MH contends that the current situation of a high Canadian dollar and flatter U.S. electricity prices is temporary. Accordingly, the Corporation's forecasts of future energy prices reflect the assumption of higher prices aided by a substantial environmental premium.

MH's IFF 07-1 appears to reflect export market conditions as experienced in fiscal 2007/08 to the end of September 2007, but also assumes that the

Canadian dollar will return to $1.16 USD/CDN exchange rate by the end of the forecast period (fiscal 2017/18).

The following table illustrates export values employed in IFF 07-1, and shows the difference in export market prices that could be expected should the Canadian dollar remain at or close to unity:

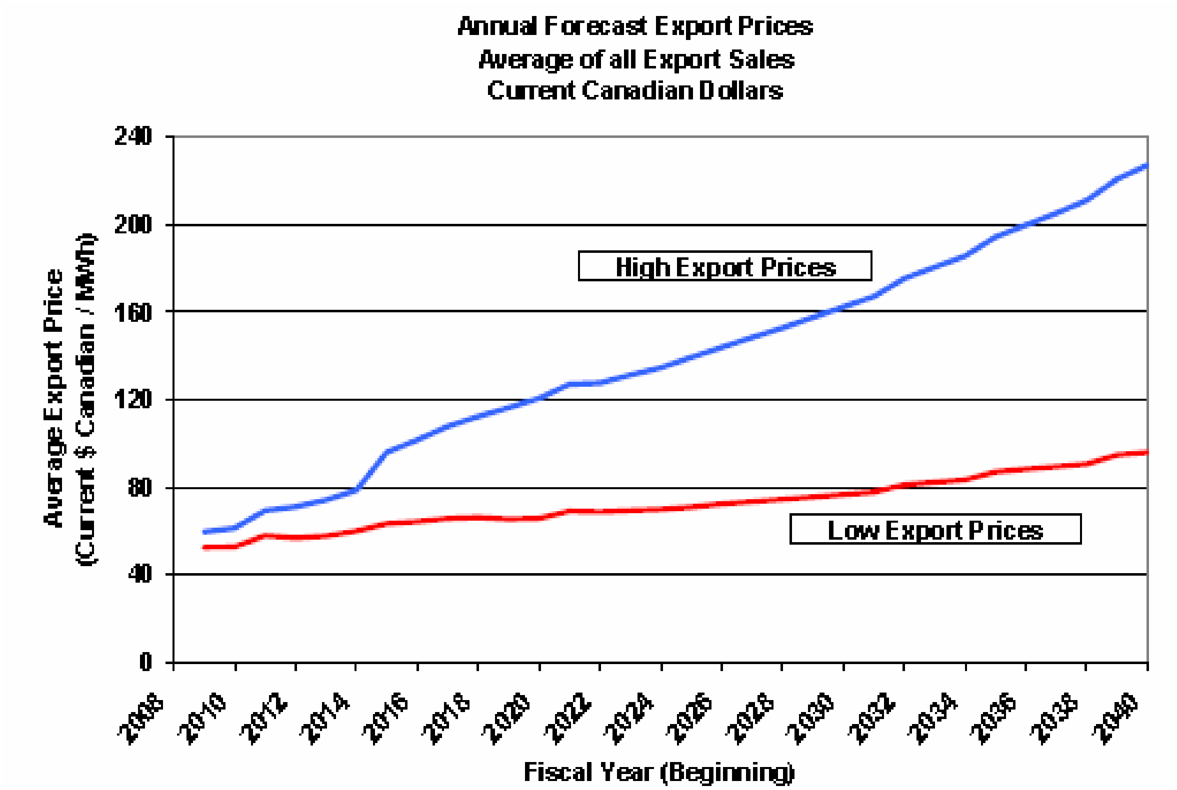
Year	IFF 07-1 (CDN $) ¢ Per kW.h	[1] USD/CDN$ EXCHANGE RATE	[2] IFF 07-1 (Unity) ¢ Per kW.h	[3] Forecast Range PUB/MH II-38 ¢ Per kW.h
2007/08	5.2¢	1.07	4.9¢	5.3-6.2¢
2008/09	6.2¢	1.08	5.7¢	5.3-6.3¢
2009/10	6.3¢	1.11	5.7¢	5.3-6.4¢
2010/11	6.4¢	1.11	5.8¢	5.5-6.4¢
2011/12	6.7¢	1.11	6.0¢	5.9-7.0¢
2012/13	7.1¢	1.13	6.3¢	5.9-7.2¢
2013/14	7.4¢	1.14	6.5¢	6.0-7.5¢
2014/15	7.8¢	1.16	6.7¢	6.3-8.5¢
2015/16	8.9¢	1.16	7.7¢	6.5-10.0¢
2016/17	9.3¢	1.16	8.0¢	6.6-10.5¢
2017/18	10.0±¢	1.16	8.6¢	6.7-11.0¢

Notes:

[1] MH's forecast of CDN $ values reflect the average forecast of four independent consultants (all employing a starting exchange rate upward of 1.05).

[2] IFF-01 export prices recalculated on a unity exchange rate basis for the entire forecast period.

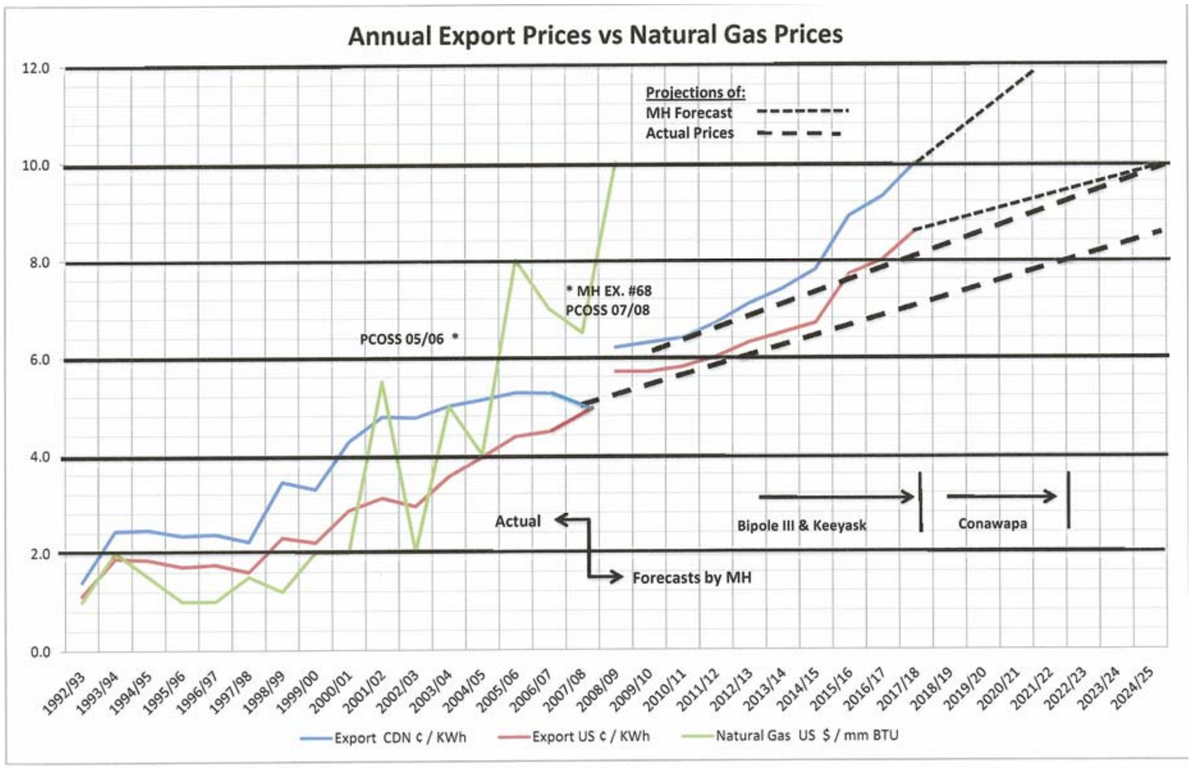
[3] In an exhibit provided at the hearing (PUB/MH II-38, below), MH's export energy price market forecast was updated from that of the 2003 Clean Environment Commission application, and suggests a significant upward movement in Midwest Independent System Operator (MISO) region prices will occur in about seven years, assuming past historical exchange rates return.



Comparing IFF 07-1 to the forecast range depicted in PUB/MH II-38 shows that MH anticipates prices in the medium to high range. This would require the exchange rate to return to 1.16 USD/CDN and significant progress on the CO_2 emissions front (recognition of environmental costs reflected in pricing). The 1.5 to 2.0¢/kW.h increase in the high export price curve forecast circa 2015 appears to coincide with MH's anticipation of legislated action on the CO_2 front.

The following chart illustrates that from the early 1990s to about 2004/05, U.S. Export electricity prices achieved by MH (USD) moved in tandem with annual average natural Gas Supply prices. Subsequently, natural gas prices have risen dramatically while electricity export prices (USD) have grown only modestly. In terms of Canadian dollars, the prices have in fact plateaued at about 5¢ per kW.h.

3.0 Forecast Revenues



The export energy prices employed by MH in PCOSS–06 and PCOSS-08 were 6.2¢ and 7.2¢ CDN/ per kW.h respectively. In IFF07-1, MH has forecast export prices (USD) to continue a gradual upward movement until 2014/15 when they are expected to step upward in response to carbon tax legislation and continue to rise more steeply to about 8.5¢ per kW.h in 2018. If a steep rise continued to 2022, export prices would be about 10¢ per kW.h.

MH has suggested that USD/CDN exchange rates will return to about 1.16 by 2015; this would yield forecast average export prices of 10¢ per CDN per kW.h in 2018, and 12¢ CDN per kW.h in 2022, and might be sufficient to support new generation and transmission development [Bipole III, Keeyask and Conawapa] if interest rates do not increase. However, if the movement to carbon taxation does not happen, lower prices may well prevail. It can be speculated the prices of 7¢ U.S. per kW.h in 2018 and 8¢ U.S. per kW.h in 2022 would result from projections of recent [2005 to 2008] actual average export prices. If the exchange rate moves to 1.16 USD/CDN as anticipated by MH, the export price forecast would be 8¢ CDN per kW.h in 2018 and about 9.5¢ CDN per kW.h in 2022.

It can be realistically speculated if the costs of Bipole III, Keeyask G.S., and Conawapa G.S. were fully allocated against export revenues, average export sales prices would have to be 11¢ CDN per kW.h to break even.

In the 1990s, natural gas prices were relatively constant $1.50 to $2.00 (USD) per BTU. Natural gas-fired electricity generation (with its low Capital Investment requirements) became very attractive as an alternative to building new coal plants. There were predictions as recently as 2001 that all new generation would be natural gas–fired, and numerous new natural gas generation plants did come into service in Western Canada and the U.S. Midwest.

In 2001/02 natural gas prices almost tripled but fell back the following year, only to renew the upward climb in 2003/04. This led to reduced natural gas generation, and consequently greater exports by MH at then favourable average prices of 3¢ to 5¢ U.S. per kW.h

The advent of Hurricane Katrina in 2005/06 led to a further doubling of natural gas prices. However, MISO average market prices for electricity only increased by about 25% and now appear to be almost static at about 5¢ U.S. per kW.h, even though natural gas prices have been above $11.00 U.S. per MBTU in June 2008 (falling back since). It appears obvious that current MISO market prices for electricity are not being driven by natural gas prices.

The Mid-Continent Area Power Pool (MAPP) merger into MISO after 2000 reduced the relative significance of natural gas generation in determining MH's export pricing. Access to more coal generation could be responsible for the low off-peak prices. Other possible explanations for this disconnect between market electricity pricing and natural gas prices are that:

- Mandated wind generation, when available, could also be used in conjunction with MH's exports during the off-peak period and create base load energy at prices only marginally above coal generated energy.
- Natural gas generated electricity provides a very limited fraction of the total energy consumed within the MISO region; in the 2005 summer, natural gas generation might have been in play about 25% of the time but only supplied about 5% of the total market energy.

Coal-fired Electricity Generation greatly influences MH export markets in the MISO region and, to a somewhat lesser extent, in Ontario and Saskatchewan. Coal based generation is inherently base load in nature (MISO utilities rely on coal and natural gas, hydro is a minor source) and the replacement of coal-fired generation by MH's hydroelectric power currently brings an average market export price significantly below 5¢/kW.h.

Consequently, at the prices MH seeks for its power (prices well above 5 cents), the Utility is not competitive for base load and can achieve export market access at better prices primarily at the time of MISO system peak loads. For MH to compete for base load, a substantial environmental premium would have to exist for clean energy; that is coal generation would have to be "penalized".

In MH's 2003 Clean Environment Commission (CEC) Application to construct the Wuskwatim G.S., the Corporation's energy price forecasts reflected environmental price premiums for its export sales. At the recent GRA, MH suggested that these scenarios are still valid and will come into play within the forecast period. Within its 2003 CEC submission, MH categorized three levels of environmental premiums in 2000 U.S. dollar terms:

- Low (long-term CO_2 valued at $10 U.S./ton)
- Medium (long-term CO_2 valued at $20 U.S./ton)
- High (long-term CO_2 valued at $25 U.S./ton).

For MH's future exports of hydraulic generation to realize prices of 7 cents or more per kW.h, it appears that coal generation by MISO market utilities would have to be assessed substantial CO_2 emission premiums.

Natural Gas Electricity Generation at current natural gas prices can readily be displaced economically by MH exports in the MISO region, even during peak load periods. During off-peak hours, there is little (if any) natural gas generation to displace, resulting in low export prices for the Corporation.

MH's own natural gas generation of electricity is not economical at today's natural gas supply prices. Incrementally, these generation costs range from 5¢/kW.h with natural gas at $3.00 CDN/GJ, to 15¢/kW.h with natural gas at $9.00 CDN/GJ.

MH has suggested that pending U.S. legislation on Green House Gas emissions will make new natural gas generation plants more economically attractive to U.S. utilities, as coal should bring much higher environmental cost premiums than natural gas. Such a development would favour MH and its price forecasts over the longer term.

Wind Generation has essentially been mandated in some U.S. states which now specify minimum levels of required renewable energy (not including large hydro) that must be incorporated within the supply system. As MISO market wind may be displacing MH exports (on an energy supply basis), about one third of the time, MH exports may also be called upon to serve to back up this generating source for the Americans.

3.2.2 Foreign Exchange

As suggested above, MH's export revenue is significantly influenced by the foreign exchange rate.

MH's present forecast of the exchange rate was updated in July 2007, and the exchange rate utilized in IFF MH-07-1 ranges from 1.07 USD/CDN to 1.16 USD/CDN. The exchange rate used for fiscal 2007/08 was 1.07 USD/CDN, and 1.08 USD/CDN was used for fiscal 2008/09, yet the CDN dollar remains close to parity with the U.S. dollar.

MH's exchange rate forecast fails to fully recognize the significant appreciation of the CDN dollar versus the U.S. dollar, and the underlying reasons for the appreciation that suggest the change may persist. This has had the effect of MH overstating both the value of U.S. export sales and finance expense.

MH indicated that if the CDN dollar was to remain at par with the U.S. dollar throughout the IFF forecast period, this would result in a decrease of $170 million in its forecast retained earnings. MH indicated that due to its Exposure Management Program, the exchange impact will be limited to the portion of dollar flows that are not perfectly hedged.

MH remained of the view that over the long term the CDN dollar will weaken against the U.S. dollar, consistent with its long-term 1.16 USD/CDN foreign exchange forecast.

3.2.3 Long-Term Export Contracts

MH has typically entered into long-term export contracts for the sale of dependable energy surplus to forecast domestic customer base loads. By and large, these contracts are for peak (5 x 16) energy sales and reflect a commitment by MH to provide a defined amount of capacity (MW) and energy (GW.h) during the 5 x 16 period throughout a year at an agreed price. MH has also entered into diversity agreements that involve the seasonal exchange of firm energy between the Corporation and a MISO counter-party, at prevailing market rates.

MH currently has executed agreements and/or term sheets for about 3,500 GW.h (900 MW) per year of firm energy for both 2008/09 and 2009/10. These volumes essentially utilize all of MH's dependable energy resources available for export.

The 500 MW commitment to Wisconsin Public Service (WPS), to commence in 2019, will increase MH's firm export requirements to 3,600 GW.h, and this is substantially above forecast dependable energy resources in place at that time. MH will require the Keeyask Generating Station to be in place or, alternatively, will have to employ natural gas turbines to provide the energy. MH will need to proceed with its new generation and transmission plans in a very timely fashion to avoid the high costs that would accompany being obliged to generate power through natural gas, import the power or buy the commitments out.

When the 250 MW contract with Minnesota Power takes effect in 2020, MH will then be committed to supplying 5,000 GW.h of firm energy into the U.S. If Conawapa is not in-service by then, natural gas turbine generation and more wind generation (or imports) will be required to offset a shortfall that could approximate 2,000 GW.h in 2020.

3.2.4 Inter-Tie Limitations

Extra-provincial sales or purchases of electricity are achieved at Manitoba's borders through a number of two-way transmission connections to the U.S., Ontario, and Saskatchewan. Theoretically, MH should be able to export a maximum of about a) 25,500 GW.h/year into the U.S., b) 2,600 GW.h/year to Ontario, and c) 3,900 GW.h/year to Saskatchewan.

To date, MH's maximum annual exports have been 16,000 GW.h, and those primarily went into the U.S. market. This means that about 7,000 GW.h/year can be exported during the 5 x 16 peak period and a further 9,000 GW.h/year during the off-peak periods. Consequently, during median flow years, MH can provide 3,500 GW.h to its existing firm export contracts and another 3,500 GW.h into the U.S. or other markets at peak period pricing. Other available energy can only be exported during off-peak periods, and at significantly lower prices.

During high flow years, MH can be faced with selling about as much as 9,000 GW.h at off-peak prices. This depresses the average export price achieved, but increases overall revenue.

3.2.5 Potential Hydraulic Generation

Reservoirs within the Nelson-Churchill drainage basins allow MH to store water for later generation of electricity. This 'energy-in-storage', held at virtually no economic cost to MH, permits the Corporation to shift energy generation into other seasons of the year to meet variable domestic demand for electricity and to optimize export sales.

At the time of the hearing, MH's energy-in-storage was near the historic high level achieved in 1977 when Lake Winnipeg Regulation and Churchill River Diversion came into service. Lake Winnipeg water levels were at the high end of its operating range; flows on the Winnipeg River and the Churchill River were above normal; Saskatchewan River flows were near normal; and only Red River flows were below normal. This situation augurs well for fiscal 2008/09.

In IFF 07-1, MH predicted hydraulic generation of 31,000 GW.h for 2008/09 (representative of about 1,000 GW.h above the median flow scenario), reflecting the-then (at the time of the forecast being prepared) high level of energy-in-storage and median river flows. Current indications suggest hydraulic generation will remain above median for 2008/09.

3.2.6 Fuel and Purchase Power

In defining ”dependable energy” available for export contracts, MH counts on about 4,300 GW.h of thermal energy, available to utilize in a worst-case situation. In reality, MH has typically employed about 800 GW.h of coal-fired thermal generation, but, due to the high cost associated with natural gas, rarely has MH fired up its natural gas-fired thermal generation for delivery of energy to the market.

In IFF 07-1, MH expects to employ thermal generation of 350 GW.h and 200 GW.h respectively in fiscal 2008 and 2009. In subsequent mean (average) flow years, coal generation would be fully utilized to support export sales.

IFF 07-1 anticipated that imports of 1,200 GW.h at a cost of about 5¢/kW.h would be required for purchase in fiscal 2009, with a further 100 MW of wind energy purchases. In mean flow years (that is, average flow conditions), about 2,000

GW.h of imports are expected to be required, in addition to increased wind energy purchases to meet domestic and export commitments.

Power purchase unit costs beyond 2008/09 are forecast to be about 0.5¢/kW.h below average export prices. Presumably, this expectation reflects anticipation of a degree of off-peak purchases for on-peak sales.

MH is also involved in short-term 'energy trading' in the MISO market. MISO transmission rights allow for energy to be purchased from MISO utilities for resale, either to another MISO utility or to Ontario, all within very narrow windows of time. No internal MH generation of energy is employed in short-term energy trading. Usually these trades produce a profit; and both the purchases and sales are recorded in MH's records as revenue and expense.

3.2.7 Costs of Export

As reflected in MIPUG's evidence presented at the hearing, PCOSS-08 results indicate generation and transmission 'bulk power' unit costs for metered energy, as follows:

- Residential 3.72¢/kW.h
- GSS-ND 4.12¢/kW.h
- GSM 3.84¢/kW.h
- GSL>100 3.29¢/kW.h
- Exports 4.83¢/kW.h

These costs neither include existing DSM nor the uniform rate adjustment, nor reflect net export revenue allocations. The class variations in generation and transmission pricing are largely attributable to the impact of distribution system losses and class variable load factors.

If the above values were recalculated at generation, each domestic class would be reported as incurring 3.0 to 3.2¢/kW.h of generation and transmission costs, and exports would be indicated to incur about 4.4¢/kW.h of generation and transmission costs. The latter indicated export cost compares to MH's forecast export price of 7.0¢/kW.h (and the actual export price of 5.0¢/kW.h for 2007/08).

In the absence of exports, MH's total costs would be lower by:

Share of generation and transmission costs	$167 M (including water rentals)
Imports	$134 M
Thermal fuel cost	$ 23 M
MISO, etc./trading distribution costs	$ 20 M
	$344 M

Even without an export operation, MH's costs would still reflect:

Uniform rate adjustment	$ 17 M
DSM	$ 25 M
	$ 42 M

Without an export operation (also without a corresponding import capability), MH's costs would be expected to be higher because of a requirement for the additional usage of natural gas turbine generators, the costs of which are estimated to be between $50 million and $100 million/year.

3.3 Interveners' Position

None of the interveners actively questioned the reasonableness of MH's domestic and export revenue and price forecasts. While RCM/TREE expressed concern about the growth of domestic load and the potential for that to result in reduced exports, the pricing of such exports was not subject to Intervener comment.

3.4 Board Findings

Overall, in the three-year period 2005 to 2008 MH has exceeded forecasted export revenues despite significantly lower than forecast export prices. Substantially above-average water flows and hydraulic generation has allowed for the higher export volumes, which have more than offset the lower prices.

Export prices in the last three years have averaged about 5.0 CDN¢/kW.h for dependable (firm) and interruptible energy sales. These pricing levels, when adjusted for the exchange rate, suggest a 4.6 U.S.¢/kW.h average MISO market rate. This is substantially below MH's IFF projections for the last three years.

MH's dependable sales into the MISO region in 2007/08 earned about 5.3 U.S.¢/kW.h for 5 x 16 energy. This price was similar to that experienced in 2005/06 and 2006/07, for the period of time that followed by a major escalation of natural gas prices after the damages of hurricanes Katrina and Rita were largely repaired and demand fell with weather deviations. It does not appear that export contracts that came into force about 2005 have provided any market price escalation beyond the consumer price inflation.

MH's opportunity sales into the MISO region in 2007/08 earned about 4.6 U.S.¢/kW.h. This price was also very similar to prices in 2005/06 and 2006/07. It also continued to track below the firm energy price - contrary to MH's forecasts of 2005.

MH's export market prospects in Ontario and the MISO region have not improved since the CEC market analysis. Rather, it appears that competition from other energy sources - coal, wind, nuclear and purchased co-generation - are reducing the potential.

Accordingly, MH's projected export prices in IFF 07-1 may be overly optimistic, in that they require additional demand for MH exports and significant environmental premiums in future contracts. American electricity prices are also contingent on achieving decisive U.S. actions with respect to GHG emission controls in the near future.

Overall, there are logical bases for the Board questioning MH's forecast of export pricing in IFF 07-1. Lower export revenues will result if:

- Exchange rates remain closer to unity;
- CO_2 pricing does not progress to a $30 CDN/tonne level in MH's market area within the forecast period;
- New coal generation plant in MISO region does not include substantial CO_2 emission reductions; and/or
- Inter-tie transmission capabilities into MISO are not significantly increased.

Export Sales

For reasons of confidentiality (commercial sensitivity), MH did not provide specific contract energy prices to the Board; the Board was not willing to accept the information in confidence. However, from public information it can be inferred that MH currently has contracts providing 5.5¢/kW.h and may be considering future contract prices that would result in average export revenues of about 7¢/kW.h or less (for firm and opportunity sales) in the absence of legislated carbon pricing in the U.S.

As such, the Board is unable to assert that MH will not be hard pressed to achieve the forecast export energy prices implied in IFF 07-1. Off-peak pricing is usually several cents/kW.h lower than on-peak prices and tends to lower the average export revenue price. It is possible, perhaps probable, that pending contract negotiations will achieve some indexing relative to natural gas prices and inflation. Indexing to coal generation prices (if employed) would rely heavily on possible future carbon pricing, which, as yet, does not have a definitive timeline.

MH export contracts are priced at 5.3¢/kWh, well below forecast average prices of 6-7¢/kWh. Consequently, opportunity sales prices would have to be upwards of 7¢/kWh, levels not evidenced by the information that is available. MH opportunity export sales are expected to return 4.6¢/kW.h in 2007/08 under a high water flow scenario, and these prices did not exceed firm contract prices. In short, MH's export market pricing has not lived up to the potential anticipated in the 2003 CEC market analysis.

MH's IFF 07-1 forecast export prices are based on a low CDN dollar and the presence of environmental premiums (GHG emissions) for both dependable and interruptible export sales. Existing contract and recently-announced term sheet prices do not appear to provide significant market price escalations beyond general consumer price inflation. In fact, MH's IFF 07-1 forecast export prices appear to require substantial carbon emission premiums, likely to be well in excess of recently suggested cap and trade CO_2 prices.

MH's IFF 07-1 forecast prices may only be achieved by a combination of:

- Exchange rate returning to 1.16 USD/CDN;
- New coal plants in MISO being required to show substantial CO_2 reduction; and

- Additional inter-tie transmission capability being added in very near future.

MH's most recent commitment to continue supplying peak energy into the MISO region for the 2010 to 2020 period is expected to backstop substantial new wind energy projects in the region. By taking hydraulic energy from MH when wind is not blowing, the receiving utility will be able to blend the costs and achieve possible GHG savings of wind energy with peak energy contract prices from MH and off–peak energy purchases at typically low spot market prices. The resulting average cost of electricity for the U.S. utility could be below MH's forecast export prices.

This suggests that MH's practice of selling all of its available energy capable of being transmitted during off–peak hours supports MISO's energy blending process. It ensures that, in general, substantial surplus energy is available at low prices during the off–peak.

In the Board's view, it might be in MH's best interest to withhold this energy from the market. At minimum, the Board suggests that MH consider this option and the Board will require that MH file a report on this option, providing the option's pros and cons.

Inter-tie Capabilities

Even in the absence of major new generation, additional inter-tie capability would enhance the value of MH's exports in above median flow years. As yet, MH has not gained formal commitments from cross-border counter-parties to expand inter-tie capacity.

Existing transmission inter-tie capacities are a serious impediment to higher prices; current limits are restricting peak energy sales and resulting in frequent off–peak sales at very low prices.

Recent term sheets signed by MH with Minnesota Power and Wisconsin Public Service offer hope for additional transmission capacity from the Manitoba border into and from the MISO market. This, coupled with new transmission from Riel Station to the U.S. border, could add appreciably to MH's export market potential.

While the concept of an East–West transmission grid has received some political support, there currently seems to be only limited prospects for enhanced export capabilities for MH into Ontario and Saskatchewan. As such, MH does not have an alternative market at the MISO scale.

Hydraulic Generation

MH has enjoyed favourable water supplies in 12 of the last 16 years. On a long-term basis, a reversal of this situation is a virtual certainty. Below median flow years and droughts are in the Corporation's history and can be expected on a regular basis; MH has had a beneficial "run" of better-than-normal water flow conditions now for the better part of two decades, a period of time that has seen MH's highest and lowest net income years (the lowest being the drought year of 2003/04).

Because energy-in-storage normally cannot be substantially carried from year to year, lower hydraulic generation during the forecast period through 2017/18 is an issue of realistic possibility. Export sales are likely to be reduced significantly in below-average flow years, and increased imports at higher cost per unit than the unit value of sales can also be expected in such years.

In the absence of higher export sale prices, MH should expect lower export revenues as hydraulic generation reverts to median, near-normal and below-median levels in the upcoming years. The favourable water supplies experienced in 12 of the last 16 years cannot be expected to continue without interruption.

While MH does not provide specific contract information for reasons of commercial sensitivity, access to this information is essential in order to confirm existing and projected contract prices of between 5.5¢/kW.h and 7.0¢/kW.h, and to ascertain what environmental escalation assumptions are being “banked” on. Given the crucial nature of these contracts and assumptions and potential impact on domestic rates, the prior review of upcoming export contracts by this Board would seem wise and appropriate.

Fuel and Purchased Power

A number of questions require responses in assessing MH’s forecasts, these include:

- Does IFF 07-1 adequately represent MH’s prospects for domestic and export revenues?
- Has MH adequately defined potential energy for export sales, export sale prices, and energy purchase costs (thermal fuel, wind, and imports)?
- MH’s coal generation, on a fully costed basis (approximately 6.5¢/kW.h), probably can compete in the MISO market during the peak load periods as it would displace gas generation. On an incremental fuel and variable Operating and Maintenance cost basis (approximately 3.5¢/kW.h) MH’s coal generation is an attractive export product.
- If the Brandon Coal Plant is either ’moth-balled’ or limited to emergency operations after 2011/12, in accordance with the announced intention of government, MH will have to expect to import, in a median flow year, an additional 800 GW.h at a cost of between $10 - 20 million/year.

- The allocation of MH's system costs in PCOSS-08 suggests that exports incur up to about 5.0¢/kW.h in costs for generation and transmission. Recent average export prices have been only slightly above this cost level.
- With the large investments required to meet domestic load and committed and/or contemplated export levels, there may be a need for export revenue prices even higher than the average 9¢/kW.h projected for 2017/18 under IFF 07-1. An updated IFF that extends out to at least fiscal 2027/28 should be provided to the Board by MH, this to project export revenue requirements and domestic rate levels required to support the current assumptions as to the economics supporting export commitments and capital expenditure plans.

In light of the many complex issues and questions related to MH's export program, the Board will direct MH to file a report by January 15, 2009 addressing the following:

a) An Overview of strategy, options, and historical costs and revenues;

b) Historical prices (monthly for the last five years) for exports including both on peak and off-peak;

c) Existing and pending contract commitments with forecast revenues, both aggregated and also disaggregated (in confidence if necessary);

d) Forecast export revenues – until 2028 identifying opportunity sales distinct from firm contract sales- broken down by on/off-peak;

e) Detailed assumptions used in market price forecasts (filed in confidence if necessary);

f) A testing of MH's assumptions through detailed sensitivity analysis for upper/lower quartile water flows, foreign exchange, domestic load growth and natural gas prices; and

g) Given the crucial nature of these export contracts and assumptions and the potential impact on domestic rates, MH file for Board review all upcoming export contracts.

4.0 Finance Expense

4.1 Changes in Finance Expense

The Corporation's finance expenses were $454 million in 2003/04, then-representing over 26% of total operating expenses. Finance expenses increased to $472 million in fiscal 2006/07, yet for the fiscal years 2003/04 through 2006/07 actual finance expenses were $172 million lower than forecast in IFF 03-1 (2004 GRA), as a result of declining long-term interest rates and the strengthening of the Canadian dollar.

MH forecast finance expenses of $404 million for fiscal 2007/08, and to increase by $22 million to $426 million in fiscal 2008/09 (the latter then to represent 29% of forecast annual operating expenses). The increase is attributable to higher debt levels and to a lesser degree, an increase in the debt guarantee fee paid to the Province, in aggregate offset by foreign exchange gains on the sinking fund related to changes in accounting standards for financial instruments (discussed below).

MH capitalizes interest on all capital projects during the construction phase, and does not amortize these costs and reflect them in rates until the project is in service. MH's finance expense for its electric operation before capitalized interest was forecast at $515 million for fiscal 2008/09 and $426 million on a net basis, after deducting capitalized interest of $89 million.

MH's gross finance expense is forecasted to grow to $906 million by 2017/18, and to $616 million on a net basis (again, after adjusting for capitalized interest of $290 million).

4.0 Finance Expense

Finance expense and capitalized interest for the years 2009 through 2018 are as follows:

Finance Expense ($ millions) **For the years ended March 28/29**	**IFF MH07-1**									
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Gross Finance Expense	$ 515	$ 572	$ 609	$ 640	$ 657	$ 695	$ 756	$ 803	$ 864	$ 906
(Less) Capitalized Interest	(89)	(126)	(158)	(141)	(104)	(152)	(209)	(247)	(285)	(290)
Total Finance Expense	$ 426	$ 446	$ 451	$ 499	$ 553	$ 543	$ 547	$ 556	$ 579	$ 616
% Capitalized	17%	22%	26%	22%	16%	22%	28%	31%	33%	32%

MH forecast that its debt would grow from $8.0 billion in 2008/09 to $13.6 billion in 2017/18, a projected increase of $5.6 billion. The major increase in finance expense (before and after the deduction for capitalized interest) relates to the planned new major generation and transmission projects.

Over the planning period to 2017/18, capitalized interest is expected to aggregate to $1.8 billion. And, once the projects are in-service, the interest costs that have been previously capitalized will begin to be amortized/expensed, to be recovered in MH customers’ rates.

In addition to the major capital expenditures included in the capital expenditure forecast provided at the hearing, MH also indicated that due to potential new export contracts, it may incur at least $6 billion more in capital costs and debt for additional required major generation and transmission facilities.

If these plans are implemented, MH’s long-term debt may approach $20 billion by 2022, a large number, particularly in comparison with current provincial debt of approximately $11 billion.

4.2 Exposure Management Program and Foreign Exchange

MH has an Exposure Management Program (EMP) to manage the Utility's exposure to USD-foreign exchange fluctuations. The EMP operates by establishing a natural hedge between USD cash inflows from export revenues and USD cash outflows (long term debt coupon and principal payments, thermal fuel purchases).

The Overall Exposure Strategy concerns itself with a horizon of up to 30 years, and attempts to limit overall US foreign exchange fluctuations to within a range of + or – 20% of total debt. Only the portion of the USD inflows and outflows that are not matched under MH's EMP may affect annual net income. Fluctuations outside the 20% parameter are valued at the market exchange rate, and affect the annual financial result. The exchange rate at year-end is used for the balance sheet presentation of USD-denominated debt and investment instruments.

Commencing with 2007/08, the new standard of the Canadian Institute of Chartered Accountants (CICA) for the recognition and measurement of financial instruments and for hedges will apply to MH, and the forecast result was included in the IFF MH07-1.

The new standard requires significant changes in MH's accounting for financial instruments and hedging relationships, as well with respect to the recognition and presentation of foreign exchange gains and losses in annual financial statements. The change is expected to result in positive impacts to net income in the first two years of the new standard, benefiting 2007/08 by a forecast $37 million and 2008/09 by $9 million.

As a result of the implementation of the accounting change, the Board notes that MH has forecast amending opening retained earnings for 2007/08 by a one-time increase of $65 million.

4.3 Debt Management

4.3.1 Long Term Debt

MH's debt was $7.3 billion as at March 31, 2007, and forecast to increase to $8 billion by March 31, 2009. MH must rely on debt as its primary source of capital to finance new major generation and transmission projects, as government does not inject capital into the organization but relies on retained earnings from operations to provide capital.

To hold borrowing to a minimum required level, MH funds all routine capital construction from internally generated funds (i.e. from net income). Non-routine and major capital expenditures under way or planned include major new (other than the Pointe du Bois revitalization) generation and transmission projects and the new downtown Head Office building.

MH is in an expansion mode with planned capital spending of $11.3 billion over the eleven year period between fiscal 2007/08 and March 31, 2018. Over that period MH plans on spending $3.8 billion on its regular capital program and $7.5 billion on New Generation and Major Transmission and the Head Office project, as previously reported. As the result of recent export undertakings, yet to be formally confirmed, MH also expects to expend and borrow a further $6 billion by 2022, in addition to the $11.3 billion noted above.

Generally, and on average, debt financing is expected to fund approximately 62% of capital expenditures, with the remaining 38% to come from increased retained earnings, the latter from domestic rates and net export profits – the percentages reported excluding the additional $6 billion of debt related to above.

All in, including the additional $6 billion, MH forecasts an increase in its debt, from 2008's $7.3 billion to almost $20.0 billion by 2022.

4.3.2 Fixed vs. Floating Rate Debt

Pursuant to *The Manitoba Hydro Act*, MH's short-term debt limit has been set at $500 million; MH uses short-term debt to fund seasonal working capital requirements and bridge the timing before new long-term debt issues.

Historically, and in a typically upward sloping yield curve environment, the borrowing costs of fixed rate long-term debt tends to be higher than for short-term debt, though long-term debt fixes the interest rate for the full and longer period of the term, therefore reducing the risk of having to refinance at higher rates. In contrast, the borrowing costs of short-term or floating rate debt tend to be lower on average than for long-term debt, but are fixed for shorter periods, increasing the risk of having to refinance the debt at higher interest rates.

MH's reported policy is to limit the level of its floating rate debt to no more than 30% of total debt outstanding, and to manage the level of floating rate debt within a target range of 15% to 25% of total debt.

MH utilizes these target guidelines in an effort to provide rate payers with the economic benefits associated with the typically lower interest rates of short-term debt while protecting their customers against the risk of higher refinancing charges by reliance on the majority of borrowing being through long-term bonds.

MH's percentage of floating rate debt at each quarter end over the past three fiscal years has been:

Period Ended	**Floating Rate Portion**
Mar-2004	21.85%
Jun-2004	19.33%
Sep-2004	18.58%
Dec-2004	19.34%
Mar-2005	18.76%
Jun-2005	17.88%
Sep-2005	18.18%
Dec-2005	18.00%
Mar-2006	16.61%
Jun-2006	17.52%
Sep-2006	17.71%
Dec-2006	18.20%
Mar-2007	18.98%

Over the past four years, long-term interest rates have been at recent historic lows, and MH's general preference during this period has been to fix the majority of its new financing at the relatively attractive and low long-term interest rates. The strategy of favouring long-term fixed rate financing during periods when long-term interest rates are low relative to historic norms, and when the premium associated with long-term fixed rate debt is low and the yield curve is relatively flat, may produce costs over the long-term similar to that of a strategy of adding more floating rate debt, but with the added benefit of reducing the volatility of interest expense.

4.3.3 Sinking Fund Management

MH's bonds obligate the Corporation to establish and maintain a sinking fund, that are segregated investments held towards ensuring repayment of the debt. This obligation is currently legislated.

The legislated minimum contribution requirement is 1% of the long-term debt outstanding at the end of the previous year, plus 4% of the balance of the sinking fund at that date. Contributions for fiscal 2007/08 and 2008/09 will be equal to the legislated minimum, and total approximately $100.6 million and $109 million, respectively. MH has $246.5 million of USD denominated debt maturing during fiscal 2008/09, which is forecast to be fully retired through the sale of the related sinking fund investments.

MH reported that changes to CICA accounting standards with respect to Financial Instruments have made sinking funds less valuable, and, as matters were currently understood, the Corporation did not foresee any negative impacts from either borrowing at current interest rate levels, or to access capital from an elimination of the sinking fund requirement from its Act.

MH alluded to a possible transitional phase that could be considered that would, over a few years, substantially reduce or eliminate the Sinking Fund. MH has further suggested that such an elimination might be associated with a forecast cost saving of $93 million over the 11 forecast years of IFF07-1.

4.4 Interveners' Positions

The Coalition

The Coalition observed that MH has kept floating rate debt at about 20% of the Corporation's overall debt portfolio, which now exceeds $7 billion. The Coalition noted that MH's longstanding policy is to have no more than 30% of its debt in the short-term floating category, and that it has held to a target guideline of between 15% and 25% of total debt for the category. The Coalition noted that the policy is over 20 years old and cited studies indicating that employing a higher proportion of short-term floating debt than has been and is the current practice may lower interest costs and reduce finance cost volatility.

The Coalition submitted that while floating debt appears to offer economic benefits, high levels of such debt doesn't necessarily lead to the lowest level of risk. Coalition stated that with MH's overall debt in excess of $7 billion and with the current level of short-term debt in the range of 15 to 25% of that total, there appears to be a potential to move approximately $700 million of currently long-term debt to short-term, and that if by so doing MH was able to reduce its interest cost by a mere five basis points, annual savings of $3.5 million would result.

The Coalition expressed concern that MH has been managing its floating debt policy at the bottom end of the 15 to 25% range, and noted that in the 13 quarters between March 2004 and March 2007, MH's proportion of floating debt was below 20% for 12 of the quarters. While not suggesting mismanagement of the debt portfolio, the Coalition suggested the potential for savings and the level of risk related to decisions to be made warranted a re-examination of the current policy.

The Coalition recommended that the Board request MH to engage an independent review of its floating vs. fixed target range maximum, with consideration of options to be in terms of economic benefit and stability.

MIPUG

MIPUG requested that the Board direct MH to seek relief from the province with respect to all sinking fund requirements as soon as possible, and that the sinking fund requirement for MH's debt should be eliminated. MIPUG noted the projections of savings to come with such elimination, that being $93 million over the IFF07-1 forecast period. MIPUG noted that MH had indicated that the Corporation does not expect that the elimination of the sinking fund requirements would have any adverse affect on its borrowing rates, its ability to access capital markets, its available range of borrowing instruments, or the debt rating for the Province of Manitoba.

MIPUG suggested this was an urgent matter, given the scale of borrowings anticipated over the next 15 years, and in light of the forecasted reduced cost of longer-term borrowing.

4.5 Board Findings

Finance Expense

The Board is concerned that the projected growth of finance expense through to 2017/18 and beyond is being obscured by the increasing amount and percentage of interest being capitalized i.e. $89 million or 17% of gross finance expense in 2008/09, to increase to $290 million or 32% in 2017/18. Given MH's expansion plans are consummated, MH's debt is expected to increase to about $20 billion by 2022, and gross finance expense is expected to almost double from 2008/09 levels to over $900 million in 2017/18, while the annual amount of capitalization of interest is expected to more than triple, masking the cash cost of financing major new generation and transmission projects, costs that will ultimately have to be recovered in rates.

The Board notes that MH's policy and practice of capitalizing interest raises a question of the risk of inter-generational inequity, and requires close examination. That said, the Board realizes that if less capitalization occurred, then more of MH's current years' interest costs would be expensed and reflected in rates. In short, without capitalization, the ratepayers of today through to those of the era when the new generation and transmission assets would be in-service would face increased rates to finance capital projects, projects intended (other than through the economic benefits associated with construction) to benefit future ratepayers.

Thus, the Board accepts there is an argument for MH's current approach. To expense costs in the current period and reflect them in current rates when the costs related to the projects are not expected to provide "rate related" benefits until the future would mean charging the current generation of MH's customers for costs that, arguably, should be met by future generations.

The major question relates to risk and conservatism with respect to financial planning. Probably the best approach is a balanced one, an approach that would have current ratepayers pay for some of the costs of proceeding with new projects – which will generate current economic benefits for the Province – while holding future generations responsible for the majority of these costs, as it is those future generations that are intended to reap "rate-related" benefits from the new construction.

The potential for the approach to change lies in part with the upcoming adoption of IFRS. The new standards may not allow MH to capitalize costs for future amortization to the same degree as is now occurring. And, as indicated above, expensing costs that are now being capitalized in the period incurred will result in future ratepayers' rates being reflective not only of "current" costs, including currently amortized costs, but also cost burdens that would otherwise have been reflected in future rates for future ratepayers.

For the welfare of succeeding generations, this generation will likely have to shoulder more responsibility for the costs and risks being assumed by the capital expenditure plans of MH. This was the experience with the prior development of generating stations in the lower Nelson River – i.e. there is precedent for less capitalization of current debt costs.

Fixed versus Floating Debt

As to what represents the optimal mix of fixed vs. floating debt, the Board agrees that increasing the exposure to short-term floating rates would likely benefit current ratepayers in lower finance costs in the near term, but it might also expose future ratepayers to greater volatility and risk over the long-term (as and if interest rates increase).

Given that the debt, by its very nature, has been incurred to fund capital assets with expected lengthy service lives, MH's approach of funding the majority of its debt requirements with fixed term debt appears reasonable.

However, with the anticipated unprecedented growth in debt levels, the Board sees merit in the concerns raised by the Coalition and agrees that MH's longstanding policy related to floating debt would benefit from an independent review. Such a review may suggest a different mix between fixed and floating debt, which may reduce finance expense.

Because of the potential for MH's overall debt level reaching $20 billion, possibly over twice the debt taken on by the province on its own account (with all debt guaranteed by the province) the Board will direct MH to engage an external assessment of the Corporation's relative weighting of fixed vs. floating debt, and file a report with the Board on or before June 30, 2009.

Sinking Fund

The Board notes that elimination of the sinking fund requirement has been forecast to result in savings of $93 million over an eleven year forecast period. While the potential savings are alluring and demand a consideration of the positions of interveners and the views of the Utility, the Board believes that MH has been served well in the past by the obligation to have sinking funds. Yet, the Board accepts that its future benefit may be diminished due to changes in accounting standards and improvements in the capital markets.

The Board understands MH's perspective that elimination of the sinking fund requirement will have no impact on the credit rating of MH or the Province, nor would it limit MH's access to the capital that it clearly needs to proceed with its expansion plans.

Out of an abundance of caution, and in light of the major capital expansion and related anticipated growth in debt levels now planned, the Board will recommend that MH seek independent advice, as well as advice from government and its credit rating agencies, as to the merits of a possible elimination of the sinking fund requirements.

5.0 Operating, Maintenance, and Administrative Expenses (OM&A)

5.1 General

Over 74% of OM&A costs relate to labour costs, which include employee benefits extending to pension obligations. Actual and forecast OM&A expenses for fiscal years 2004 to 2009 are:

Operating and Administrative Costs ($000's)	Actual				IFF07-1	
Fiscal Year	2004	2005	2006	2007	2008	2009
Labour						
Wages, Salaries & Overtime	343424	354,661	370,289	383,597	411,091	425,514
Employee Benefits	59,154	68,442	70,184	73,636	78,335	79,902
	402,578	423,103	440,473	457,233	489,426	505,416
Other Expenditures						
Employee Safety & Training	-	5,275	3,686	3,487	5,267	5,367
Travel	23,062	23,534	26,212	27,729	29,679	30,399
Motor Vehicle	16,687	17,726	19,380	19,735	20,017	21,036
Materials & Tools	23,325	23,891	26,040	25,420	24,663	25,249
Consulting & Professional Fees	8,024	7,269	7,229	8,498	10,071	10,137
Construction & Maintenance Services	11,373	13,345	13,700	13,711	15,481	15,669
Building & Property Services	21,799	21,031	22,973	24,697	24,522	24,700
Equipment Maintenance	9,571	9,546	10,720	11,606	12,235	12,475
Consumer Services	5,081	4,203	4,301	4,316	4,881	4,980
Computer Services	4,547	3,959	4,293	2,622	1,077	1,102
Collections	5,035	5,161	6,790	7,218	5,359	5,466
Customer & Public Relations	4,956	5,223	5,585	6,493	4,581	4,698
Sponsored Memberships	1,163	1,149	1,012	1,187	1,172	1,197
Office & Administration	14,996	15,448	15,904	14,939	15,532	15,882
Communication Systems	2,027	1,844	1,447	1,866	1,834	1,870
Research & Development Costs	3,742	3,685	3,542	3,251	3,414	3,483
Miscellaneous Expense	1,957	2,461	2,143	2,423	2,757	2,812
Contingency Planning	-	-	-	-	4,941	7,254
Operating Expense Recovery	(17,263)	(18,104)	(19,199)	(20,579)	(19,806)	(20,192)
Total Costs	542,660	569,749	596,231	615,852	657,103	679,000
Less: O&A Charged to Centra	(52,786)	(55,232)	(53,085)	(53,505)	(56,600)	(58,000)
	489,874	514,517	543,146	562,347	600,503	621,000
Capital Order Activities	(147,693)	(157,730)	(170,459)	(176,994)	(196,853)	(207,500)
Capitalized Overhead	(58,824)	(58,174)	(62,028)	(61,887)	(63,450)	(64,500)
O&A Costs Attributable to Electric Operations	283,357	298,613	310,659	323,466	340,200	349,000
Number of Customers	501,650	505,660	509,791	516,861	520,259	524,220
OM&A Cost Per Customer ($)	565	591	609	626	653	665

Total OM&A expenses attributed to electric operations and after allocations to Centra Gas and the deferral and capitalization of such expenses to be amortized in future periods have increased from $283.4 million in 2003/04 to $349 million in 2008/09, a compounded annual growth rate of over 4%.

MH indicated that over the last few years, the Corporation has experienced cost and operating program pressures relating to: increased maintenance requirements (due to aging infrastructure); wage and benefit settlements that exceed inflation; additional overtime and increased staffing levels (to meet extra-provincial requirements); the expansion of programs (to meet higher customer numbers) and needs; and the meeting of environmental and other stakeholder expectations. These pressures were reported to be continuing and being compounded by a looming shortage of skilled labour, manifesting itself in higher training and labour costs.

MH stated that the annual compound growth in labour and benefit cost per Equivalent Full Time (EFT) position has averaged 3.8% over the period 2002 to 2007. The increases are due to a combination of general wage increases, merit and/or pay schedule increments, and other adjustments. MH reported that wage and benefit settlements that have been above the general inflation rate reflect higher compensation requirements for attracting and retaining skilled trades and professional staff and, as well, higher compensation requirements for northern staff.

Unfortunately, MH was unable to provide a segregation of OM&A expense associated with maintaining/sustaining existing assets versus expenses associated with changed processes and plans and actions related to construction of new plant.

5.2 Staffing Levels

MH indicated that between 2005 through 2009, its staffing levels were projected to increase further, by 455 EFT employees (from 5,866 to 6,321), with related labour costs to increase by $102.8 million. These increases were reported to be largely due to increased work requirements, with the largest additions expected for staffing levels in Power Supply (234 EFT) and Transmission & Distribution (142 EFT). MH attributed the growth of 180 EFT's between fiscal 2004/05 and 2008/09 as being related to meeting the Corporation's operating and maintenance needs, particularly given the plans for major expansion.

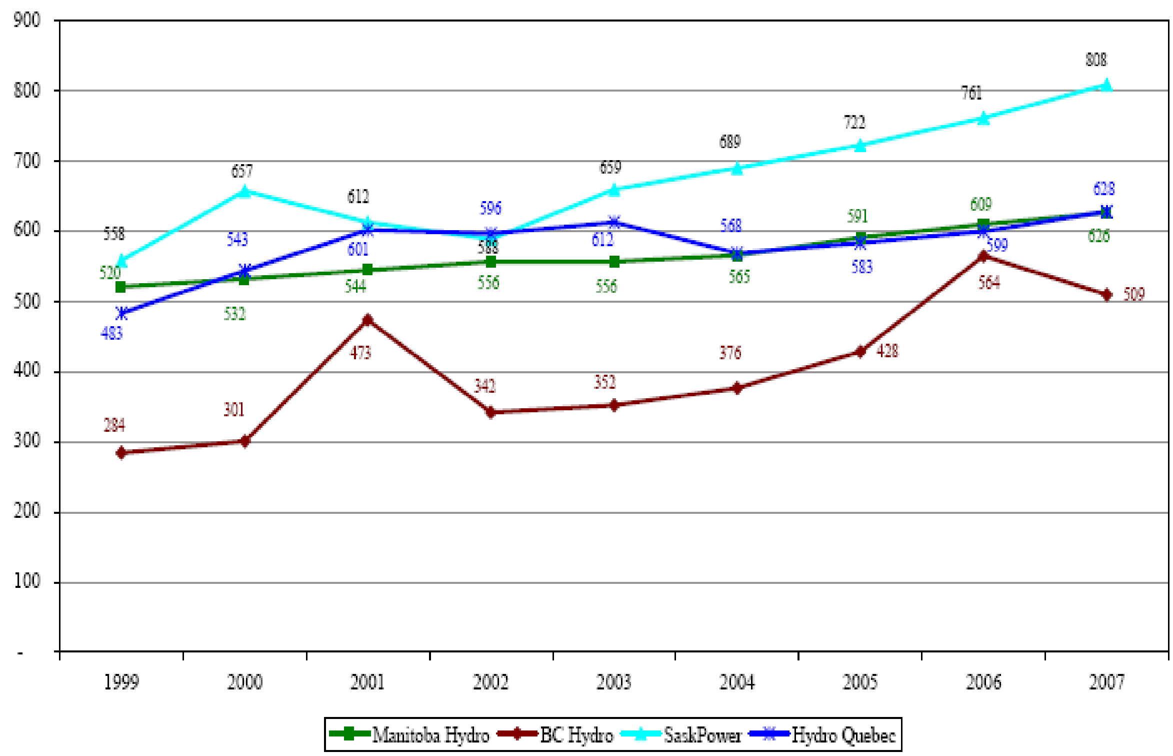
MH indicated that currently there were 200 unfilled EFT positions from the staff level forecast for fiscal 2007/08, and that between 125 and 150 of the EFT vacancies were due to difficulties in recruiting. The remaining unfilled positions were reported to be the result of awaiting the completion of the new head office and expected staff synergies to arise as a result of the consolidation of staff in one location. MH further noted that the hiring difficulty associated with the skill shortage had resulted in forecasted fiscal 2007/08 OM&A costs being $16 million less than forecast for the ten months ended January 31, 2008.

5.3 OM&A Costs per Customer

MH OM&A costs per customer have increased from $565 in 2004 to $626 in 2007. While MH indicated that it was not appropriate to directly compare its OM&A cost per employee to the ratios of other utilities, it noted that based on annual report information, Hydro Quebec's OM&A cost per customer was $628, BC Hydro's cost per customer was $509 and SaskPower's was $808, in 2007, as noted in the following graph.

MH compared its OM&A cost per customer with the other utilities for the years 1999 to 2007:

Manitoba Hydro
Operating & Administrative Expense per Customer
Comparison to BC Hydro, SaskPower and Hydro Quebec



MH reported that its OM&A expense per customer experience, relative to its established targets in the Corporate Strategic Plan, is as follows:

Fiscal year	CSP Target	Actual
2004	$600	$565
2005	$584	$591
2006	$600	$609
2007	$612	$626
2008	$640	$653 (est)
2009	N/A	$665 (est)

The Board notes that MH's OM&A costs and OM&A expense per customer levels were and are materially reduced by the capitalization of significant amounts of OM&A, making the comparisons with the other utilities of questionable value.

5.4 Capitalization of Operating and Administrative Expenditures

5.4.1 Current Capitalization Practices

MH segregates costs between operating activities, which are charged against the operating income for the year, and capital activities, which are charged to future periods and amortized over the future life of the capital project. MH capitalizes certain of its OM&A expenditures.

Many of the expenditures are capitalized as deferred charges, and are amortized over a period of years; others allocated to construction in progress and amortized once the asset is in service over its expected service life.

MH indicated that employee's timecard their activities to specific capital projects. This amount, combined with other related costs, is charged to a capital order. In addition, MH also capitalizes 'overhead' by applying predetermined overhead rates to all capital projects.

OM&A expenses were $615.8 million in 2006/07, that is <u>before</u> capitalized activities and overheads. MH indicated that approximately 29%, or $177 million of the $615.8 million, was charged to capital order activities with an additional 10% ($61.9 million) charged as capitalized overhead. Overall approximately 39% of OM&A was capitalized.

MH forecast OM&A expenses of $679 million for fiscal 2008/09, of which $207.5 million (30%) is to be charged to capital order activities and $64.5 million (9%) as capitalized overhead.

MH capitalizes annually in excess of $60 million of overhead costs to its capital projects, to be amortized when the capital asset goes into service. In addition to the capitalized overhead, MH also includes some overhead costs to determine its activity rates, which are used for allocating direct costs of labour to operations or to capital projects.

MH also capitalizes Demand Side Management (DSM) expenditures arising from its Power Smart program. DSM program costs are deferred and amortized on a straight-line basis over 15 years, regardless of the expected present value of the benefits to be realized.

The carrying value of deferred DSM was $123 million at March 31 2007, and forecast to reach $180.9 million as at March 31, 2009.

Planning Studies involve costs related to uncommitted major generation or transmission facilities. These costs are recorded as deferred charges and are amortized to operations (expensed) on a straight-line basis over 15 years. If there is reasonable assurance that a project will proceed to construction, any unamortized balance related to that project is then transferred from deferred charges to construction in progress. The carrying value of the Unamortized Planning Studies balance was $28 million as at March 31, 2007 and forecast to be $22.5 million as at March 31, 2009.

Construction in Progress consists of contracted services, direct labour, material and expense, a proportionate share of overhead costs and interest applied at the weighted average cost of capital related to projects in development. Once the projects become operational, the costs are recovered in rates through depreciation and finance expense.

Establishment of the Affordable Energy Fund (AEF) by the provincial legislature, was funded by an allocation of electricity export revenues, and is to be used to fund low-income energy efficiency initiatives throughout the Province.

The AEF resulted in the creation of a $35 million deferred charge (asset) and a corresponding $35 million deferred credit (liability) in MH's financial accounts (balance sheet). Annual program expenditures from the fund are to be expensed against income in the year incurred, with the corresponding asset and liability reduced by the equivalent amount.

The balance of the AEF at March 31, 2007 was $34 million, after deductions for low-income related DSM project expenses, including overhead allocations, and the balance of the AEF as of March 31, 2009 was forecast to be $28 million. No interest accrues on the balance.

Goodwill of $62 million related to the 1999 acquisition of Centra Gas Manitoba Inc. and $46 million of additional goodwill associated with the acquisition of Winnipeg Hydro (WH) remains on MH's balance sheet. Goodwill represents the difference between the purchase prices paid for these enterprises and the values assigned to specific assets obtained. Goodwill is not amortized unless judged to be impaired, and impairment tests are performed annually in accordance with GAAP requirements – to-date, these tests have not indicated any impairment of the recorded goodwill.

MH also capitalizes experience gains and losses on its Employee Pension Plan, and amortizes the net result over the expected "life" of the employee group. The unamortized balance was reported to currently be in the $30 million range.

As of March 31, 2007, MH had $457 million of deferred charges recorded as an asset, including rate-regulated assets which, if MH were not subject to rate regulation would be charged to operations in the period that they were incurred.

The balance of the rate-regulated assets at March 31, 2007 were as follows:

Regulated Assets ($ millions)	March 31, 2007
Deferred taxes (Centra Gas)	$ 40
Site restoration costs	$ 38
Acquisition costs	$ 26
Power smart programs – gas	$ 11
Total	$115

Income Taxes paid by Centra Gas (July 1999) as a result of its change to non-taxable status upon its acquisition by MH were deferred and are being amortized on a straight-line basis over 30 years. Acquisition costs related to MH's purchase of both Centra and Winnipeg Hydro are also being amortized on a straight-line basis over 30 years.

Site restoration costs are deferred and amortized on a straight-line basis over 15 years.

5.4.2 Mitigation Costs

MH is party to a December 16, 1977 agreement also involving Canada, the Province of Manitoba and the Northern Flood Committee Inc., the latter representing the five First Nations in the communities of Cross Lake, Nelson House, Norway House, Split Lake and York Landing.

This agreement provides, in part, for compensation and remedial measures to ameliorate the impacts of the Churchill River Diversion (CRD) and Lake Winnipeg Regulation (LWR projects). Comprehensive settlements have been reached with all communities except Cross Lake. Expenditures incurred to mitigate the impacts of the CRD and LWR projects were $17.3 million during fiscal 2006/07 and, to March 31, 2007, $616 million had been spent in the effort. MH forecast to spend an additional $30.5 million in fiscal 2007/08 and a further $29.9 million in fiscal 2008/09.

In recognition of the anticipated future additional mitigation payments, the Corporation recorded a liability of $132 million as at March 31, 2007. Mitigation related expenditures are amortized over the remaining life of the Generation and Transmission assets to which they pertain.

MH has also entered into agreements with the Province of Manitoba whereby MH has assumed certain obligations of the province with respect to certain northern development projects.

To-date, MH has assumed obligations totalling $143 million and in return, Water Power Rental charges were fixed until March 31, 2001. The remaining liability outstanding as at March 31, 2007 was $13 million.

5.5 Future Changes in Accounting Standards

5.5.1 Adoption of International Financial Reporting Standards (IFRS)

The Canadian Accounting Standards Board (AcSB) has established that 'publicly accountable enterprises' (MH, including its subsidiaries, is such a body) are to prepare their audited accounts in accordance with International Financial

Reporting Standards (IFRS). In short, IFRS is to replace current Canadian Generally Accepted Accounting Principles (GAAP) and it is to be implemented effective January 1, 2011. As annual accounts are provided with comparative information for the previous year, MH will be required to also develop IFRS-based accounts as of fiscal 2010 – 2011, to be disclosed as comparative information when it files its 2011/12 accounts.

In advance of the adoption of IFRS, Canadian GAAP standards have changed for rate-regulated operations. Specifically, section 1100 General Accounting of the CICA Handbook will apply to the “recognition and measurement of assets and liabilities subject to rate-regulation” for fiscal years beginning on or after January 1, 2009.

MH stated that the interim changes to GAAP are not expected to have an impact on its fiscal 2008/09 or 2009/10 financial results and statements. MH has taken the position that it will continue to be allowed its current accounting practices for rate regulated assets through its adoption of a secondary source of GAAP found in US accounting standards, also related to accounting for regulated operations. The assets and liabilities subject to rate regulation pursuant to US accounting standards amounted to $115 million at March 31, 2007.

Yet, early adoption of IFRS is provided for by GAAP and, depending on the actions of the Board, may result in a change in accounting for rate-regulated assets ahead of the required adoption date for IFRS.

5.5.2 Future Financial Implications of Adoption of IFRS

MH indicated that the major implications expected from the adoption of IFRS are reduced annual and forecast net income and retained earnings as of the date of adoption. These impacts are due to “stricter” standards than now exist with Canadian GAAP as to what must be capitalized as opposed to what should be charged to operations in a given year.

Although the implications for MH are not fully known, there is a likelihood that IFRS will require MH to recognize a higher level of expense each year, and a corresponding lower level of costs will be deferred and capitalized.

The current version of the International Accounting Standard (IAS) 38 - Intangible Assets, on which IFRS is based, is much more comprehensive than current Canadian GAAP. In order for an intangible asset to qualify, it must be separable from the entity, such that it can be sold, transferred, licensed or otherwise disposed of to another entity. Also, in order to record an intangible asset, it must be probable that future economic benefits are attributable to the asset and will flow to the entity.

If regulatory assets and deferred pension costs are not allowed under IFRS, the deferred balances at the date of implementation will no longer be allowed to be presented on the balance sheet and will be deducted from Retained Earnings, restating retained earnings to a lower balance.

MH stated that the full impact that IFRS will have on MH financial statements is not known at this time, as IFRS accounting standards are still in the discussion stage, with some of the discussion centred specifically on the capitalization policies of rate-regulated enterprises.

A major matter of considerable potential importance to the issue of rates to be resolved is whether IFRS will allow capitalization and deferral of certain costs for recovery through rates over future periods, providing that the utility’s regulator assures that future rates will reflect the deferred or capitalized costs.

MH indicated that it would be engaging a consultant to guide the Corporation through the transition to IFRS, and expects to have a better idea by the fall of 2008 on what impacts IFRS will have.

As of yet, there had been no preparation of pro forma IFF modeling the potential impact of the new accounting standards. MH further indicated that while the Corporation has no present plan to make an earlier adoption of IFRS, this decision may be revised once the impact that IFRS will have on its financial reporting is known.

In particular, MH testified that certain of its current capitalization policies may be affected by IFRS, and that several types of currently-deferred charges may have to be expensed for accounting purposes in the year they are incurred, unless it can be demonstrated that the charges have a future benefit to MH, thereby satisfying the requirements of IFRS. Included in deferred charges are $115 million of charges related to rate-regulated assets, which may or may not have a basis for capitalization and deferral under IFRS standards. MH further indicated that deferred charges related to Planning Studies (current balance, $28 million) and the Affordable Energy Fund (current balance, $34 million) may also not meet the IFRS capitalization criteria.

Another specifically cited major impact of IFRS adoption will be on MH's practices related to capitalized overheads, which are now in excess of $60 million annually. MH's understanding is that overheads will have to be a direct charge to specific projects, and to continue MH's current approach may involve undue administrative complexity. Potentially, the full $60 million of annual capitalized overhead could be charged against operations in the year incurred, under IFRS.

MH further indicated that the allocation of direct labour to capital projects also includes an element of overhead, which also could be in contravention of IFRS and require revision. MH indicated that such a change in this matter could result in an additional $20 million to $30 million of annual costs to be expensed rather than capitalized. (MH testified that its understanding is that overhead capitalized in the years prior to IFRS will not have to be written off, and that IFRS would be prospective rather than retrospective in this regard.)

MH also stated that its current accounting policy that amortizes experience gains and losses on the Employee Pension Plan may also be affected by IFRS, and will likely result in a one-time write-off of the then-current unamortized balance, now being approximately $30 million. The future impact on operating results and retained earnings with respect to this particular matter will depend on the experience of the pension fund to fiscal 2010 – 2011, and thereafter.

MH also stated that its capitalization of mitigation costs may also be affected by IFRS, in that although costs may still meet the standards for capitalization, the tests used to treat them as an asset may require a more direct correlation to a specific capital project than is currently used.

MH opined that its current deferral of Power Smart Programs ($123 million) can be demonstrated to have a future benefit (that being the intended and expected creation of increased export revenue) and thus, continued deferral may be allowed under IFRS. Natural Gas Power Smart Programs (Centra) were specifically identified as possibly not meeting IFRS capitalization criteria, and thus may require expensing in the year incurred.

Overall, MH advised that the changes expected to be brought on by IFRS may result in annual increases in operating expenses in the order of $100 million (now, the equivalent of a 10% rate increase for domestic customers). In addition, MH has reported a potential $100 million write-off of disallowed assets against retained earnings on implementation of IFRS (and this may prove a low estimate).

MH understands that the application of IFRS will generally be prospective but noted that there are certain electives for first time adopters of IFRS that allow a deemed approach to be used to value items such as property, plant and equipment. This, too, could involve adjustments to MH's accounts, including retained earnings.

MH advised it expected to have its consultant's advice by the fall of 2008, at which time a more definitive assessment of the impact of IFRS will be available.

5.6 OM&A Cost Control Process

MH utilizes a comprehensive budgeting process to establish and monitor its OM&A expenses. An IFF target is established through a top-down process whereby submissions are made to MH's Executive Committee for review and assessment of the amount of operating costs required to operate the utility.

The Executive Committee reviews requests and makes submission to MH's Board of Directors for approval of a final budget. Once approved, target levels are allocated to the business units, and business units prepare detailed operating plans. Business units are expected to review opportunities for both cost increases and decreases in their detailed budgeting process, and are required to submit that information to the Executive Committee to assist with the next year's target-setting process. Variance analyses are performed monthly to evaluate the performances of the business units.

MH advised that its forecast for annual OM&A incorporates a 1% productivity factor to its otherwise expected labour costs in each of the years. Labour costs represent approximately 75% of MH's OM&A costs.

In Order 07/03, the Board stated:

> "Corporate performance measures, such as the operating and administration costs per customer or per kW.h targets, are of great assistance in assessing the performance of MH's cost control initiatives compared to other utilities. The Board recommends MH aggressively pursue meeting its operating and administration costs-per-customer target while finding ways to increase productivity. The Board also encourages MH to continue to participate in benchmarking initiatives to help identify and implement further efficiencies and enhancements in its operations as compared to other utilities."

In its last three Corporate Strategic Plans (CSP), MH has outlined various strategies for improving productivity, including process benchmarking and the development of corporate and business unit performance targets. In the 2005/06 CSP, MH outlined two strategies for improving corporate financial strength: "leverage technology to reduce costs and the benchmarking of key corporate processes."

In the 2006/07 CSP, MH again outlined strategies for improving corporate financial strength, citing intentions to "leverage technology to reduce costs" and "benchmark against recognized service leaders". Yet, MH indicated at this GRA that it had not recently participated in any benchmarking exercises comparing its costs with those of comparable utilities.

In updating the Board on the status of these initiatives, MH stated that terms of reference and/or work plans have yet to be developed. MH conceded that work needed to be done in the area but stated that staffing resource limitations affect projects to be prioritized, and that benchmarking of processes was not of the highest priority level.

5.7 Intervener's Positions

The Coalition

The Coalition questioned whether MH had done what it said it would do to improve corporate financial strength. Mr. William Harper, a Coalition witness, expressed concern as to whether MH is undertaking everything it can do to identify and pursue productivity and efficiency improvements. Mr. Harper noted MH is forecasting an average annual increase in OM&A expense of 3.9% for the two year period fiscal 2007- 2009. Mr. Harper observed that the OM&A forecast of growth for this period was higher than reported in previous financial forecasts for the same period.

Mr. Harper further noted that the historical growth in OM&A over the last four years was 4% per annum. Looking forward, he noted that MH is forecasting annual customer growth of 0.6% per year, down from 0.9% historically, while wage and salary increases per FTE are also forecast to move down from 3.8% to 2.6%. Mr. Harper stated these two factors alone would suggest that OM&A spending over the two year period should be increasing significantly less than the 4% experienced historically, and less than the 3.9% increase proposed in the application.

Mr. Harper indicated that the potential annual savings related to a change in the expense growth factors would be $7 million in fiscal 2007/08 (the year finished before the hearing concluded) and $14 million in fiscal 2008/09, representing approximately a potential 1% reduction in rates.

Harper opined that overall projected OM&A cost for the periods through fiscal 2008/09 are too high and that a growth rate of 3% per annum (as opposed to the 3.9% forecast) would be more in line with the underlying cost drivers. Mr. Harper recommended the Board direct a reduction from the proposed rate increase of 2.9% (to 1.9%) to reflect this factor.

During the 2003-2007 period, MH's annual productivity improvement was reported to have been in the order of 1% per annum. However, during this period actual OM&A costs (when normalized on a per-customer basis) were generally higher than earlier forecasts and also higher than the annual CSP targets. Mr. Harper suggested that the evidence called for more discipline in the management of costs. Mr. Harper further stated that MH has consistently missed its CSP performance targets related to electric operations OM&A cost-per-customer. The OM&A cost-per-customer target for fiscal 2007/08 was $640 per customer; he suggested setting rates to match this target would reinforce the message that OM&A must be managed within expectations.

Mr. Harper suggested that productivity improvements cannot occur without action, and that what was required is an environment where opportunities for such improvements can be identified and staff encouraged to aggressively pursue them.

Mr. Harper noted that while appropriate strategies have been articulated in the CSP (such as leveraging technology to reduce costs and benchmarking key corporate processes against recognized service leaders), these steps have not been undertaken, and with respect to benchmarking, Mr. Harper noted that MH has indicated not having participated in any formal benchmarking exercises comparing its costs to those of comparable utilities. And similarly, that there has been no formal benchmarking process undertaken, even though the strategy has been articulated in prior corporate strategic plans over the last few years.

In the area of corporate and business unit performance measures, the Corporation has yet to develop a term of reference of work planned for this initiative, and Mr. Harper stated that MH should be encouraged to follow through on the strategies with a view of ensuring that the 1% per annum productivity improvement is actually achieved, if not exceeded.

The Coalition stated that given the large number of pending major new projects, it would be difficult for MH to balance priorities. The Coalition stated it was important for MH to get the “fundamentals” right, and that benchmarking has not been seen as a high enough priority for the Corporation.

The Coalition also cited the concerns raised by Mr. Bowman, a witness for MIPUG, about the divergence between forecast and actual OM&A results, a divergence that undermines the achievement of financial targets. The Coalition noted Mr. Bowman’s’ observation that systematic increases in OM&A spending have been a consistent and compounding reason underlying MH’s failure to achieve the debt:equity target of 75:25.

The Coalition noted an example from its review of IFF05-1, where the forecast cost per customer in fiscal 2009 was $338 and that by IFF-07-1 the forecast costs per customer for the same year had increased to $360. The Coalition seconded Mr. Bowman’s observation that this negative trend threatens to undermine the achievement of MH’s financial targets.

With respect to the upcoming adoption of IFRS, the Coalition supported MH’s position that it was premature to reach any conclusions on the impact at this time.

In supporting Mr. Harper’s recommendation for the Board to reduce MH’s requested revenue increase by 1%, the Coalition observed that while, at least in the short term, granting less than the requested rate increase might appear to be counter-productive to the goal of achieving financial targets, for the Coalition the short-term “pain” would likely prove beneficial in the longer term.

Reducing the requested rate increase would still leave the option for MH to put forward an application in 2009 or 2010 demonstrating improvements in cost control, and seeking increases in the revenue requirement once new capital expenses are projected and the Corporation has more certainty about the financial impact of the adoption of IFRS.

Mr. Harper suggested OM&A expenditures be evaluated on four criteria.

1. A review of cost elements, focusing on those that have changed significantly from one year to the next, to test the reasonableness of the underlying changes.
2. Evaluation of key cost drivers; with variations to be explained on the basis of unique or one-off requirements.
3. Benchmarking of the specific activity costs of the Utility against other utilities of similar characteristics.
4. Review of utility spending plans and priorities, incorporating an evaluation of an Asset Condition Assessment, to support any proposed increased spending. An Asset Condition Assessment (ACA) would, according to Mr. Harper, provide a “snapshot of the utility’s assets, noting the degree of degradation and need for rehabilitation and replacement”. For Mr. Harper and the Coalition, MH should be required to demonstrate that the condition of the assets has changed such that additional spending is required.

MIPUG

MIPUG also noted that MH's OM&A forecasts have progressively increased since the 2002 Status Update review, and that the Corporation's actual spending also routinely exceeds forecasts.

MIPUG noted that the growth in the level of OM&A spending has occurred despite prior Board directives for MH to consider cost control initiatives, citing that recently the Board noted in its decision with respect to MH's interim 2007 rate increase that it "…relies on MH's Board of Directors and senior management to continuously strive to operate the utility efficiently and incur no material costs that are not warranted from the perspective of sound business practices".

MIPUG submitted that MH's evidence in the proceeding did not support the conclusion that MH's OM&A spending is at levels consistent with an efficient operation. For MIPUG, this is particularly true when viewed in the context of forecasts prepared in recent years, as noted in some detail in the evidence of the Coalition's witness Mr. Harper which indicates increasing levels of spending.

MIPUG's witnesses Mr. Bowman and Mr. McLaren demonstrated that MH's OM&A forecasts generally trend higher, and have been doing so in each successive forecast since IFFO2-1, with IFFO7-01 being the latest of the series. Mr. Bowman and Mr. McLaren further observed that actual OM&A expenses have consistently been above the rising forecasts. In comparing the forecast period fiscal 2003 through 2013 with the forecasts in IFF 02-1 and IFF 07-1, Bowman and McLaren indicated a cumulative increase in OM&A of 10% as a consequence. MIPUG submitted that the Board should develop instructions and measures to better ensure MH applies effective cost control in the future.

MIPUG further suggested that the Board direct MH to provide full benchmarking information comparing its operations with other utilities, for review in a future GRA. MIPUG also suggested the Board direct MH to provide OM&A actual and forecast expenses by major function (Generation and Transmission, distinct from Distribution, Customer Service, and Administration). This request focused on the rationale that Generation and Transmission costs are not driven by the number of customers and, as such, a "cost/customer" ratio is of "no meaning".

For MIPUG, OM&A cost-per-customer ratios should be restricted to the distribution, customer service and administration functions.

In discussing the implications of the approaching adoption of IFRS, MIPUG stated there was insufficient information to make meaningful determinations on potential impacts on MH at this time. MIPUG urged the Board to direct MH to include with its next GRA filing an IFRS transition plan, including copies of reports produced for MH's consultants, and a summary of potential financial impacts.

With respect to adopting regulatory accounting to counter any negative implications of IFRS (in short, the construction of a set of financial statements prepared on a different basis than IFRS GAAP), MIPUG stated it was premature to consider whether such a step should be undertaken. MIPUG noted that regulatory accounting is an acceptable process currently being utilized by the Ontario Energy Board (OEB). MIPUG opined that there are an increasing number of issues that may lead to such an approach becoming justified in future, and in that event, the Board should not be averse to adopting the approach if needed.

As to MH making charitable donations, MIPUG opined that charitable donations, sponsorships and general economic development expenditures should not be reflected in rates, if material. However, MIPUG stated that there is no reason to exclude such costs in determining rates when such costs are not of material consequence to MH's financial results and forecasts. MIPUG opined that the current level of donations, as disclosed by MH in the GRA, should not be disallowed for reflection in rates, because the amounts involved are not material.

MKO

MKO agreed with the other interveners that MH should do more to restrain OM&A expenses, and also opined that MH's capital cost forecasts do not appear to be reasonable in light of the experience of actual costs. MKO also noted that MH's OM&A forecasts have generally trended higher in each successive forecast since IFF 02-1, with IFF 07-01 being the highest to date. MKO also demonstrated that MH's OM&A expenses have, in most cases, exceeded targets, and questioned MH's achievement of productivity gains.

MKO supported MH benchmarking costs against other utilities, and requested MH report to the Board why MH's costs deviate from the statistical average of benchmarked utilities.

MKO supported the suggestion of other Interveners that the implications of IFRS be considered in a future proceeding, at which time additional evidence would be required of MH and be tested by the Board and interested parties.

MKO recommended that MH revenues should ordinarily not be used for charitable purposes without specific direction from government. MKO suggested that MH had paid the Province $198 million in fees and capital taxes in 2007, and suggested that with provincial earmarking of such contributions for charitable purposes, the donations should be made directly by government, as that would be, in MKO's view, more appropriate.

MKO also recommended that MH and the Board clearly distinguish MH's necessary and appropriate costs (expenditures and investments related to operations, mitigation and agreement obligations) from "charitable donations". MKO suggested that endowments funded by MH's net export revenues (intended to benefit "MH Affected Communities", such as for regional economic development, community infrastructure and the enhancement of fish and wildlife) should not be "charitable donations".

5.8 Board Findings

The Board remains concerned with the growth of OM&A expenses, particularly the level and growth of these expenditures <u>prior</u> to deferrals, capitalization and allocations to subsidiaries.

As stated in Order 101/04:

> "The Board will expect MH to maintain vigilance over its costs, so that the additional revenues [from PUB approved rate increases] contribute as they are intended to move towards achieving the debt to equity target more quickly than suggested in MH's 2003 Integrated Financial Forecast."

Expectations from past recommendations related to OM&A expenses have not been met. The Board expects MH to control OM&A expense levels to assist in meeting its financial targets. Further control of OM&A costs is vital given the planned major capital expansion, and in light of the fact that MH will not meet its debt to equity target over the current forecast period.

And, in this Order, the Board continues to be concerned with MH's "aggressive" capitalization and deferral policies with respect to OM&A expenses. While there is an argument for the practice, the net result is that costs now being incurred are not reflected in rates until years, in fact decades, later, meaning the current generation of ratepayers leave the results for the generations that will follow to meet.

The following concern, from Order 143/04, echoes past concerns raised by the Board with respect to the capitalization policies followed by MH. The Board then stated:

> "The Board is concerned with the range and level of costs being capitalized by MH. While the Board understands that many of the projects undertaken by MH are long-term in nature, both from a benefit and cost perspective, aggressively capitalizing costs and selecting long amortization periods increases the rate risks to future generations of electric customers. If the Board questions whether aggressive capitalization policies are prudent...... The Board does not dispute that MH's accounting is based on GAAP, only that GAAP also provides for a more conservative capitalization approach."

In Order 117/06 the Board further stated:

> "The Board is concerned with MH's present capitalization and notes MH's comment that net export revenue represents a form of "windfall" which cannot be guaranteed to continue at recent levels. Even though net export revenues have been significant over the past decade, progress towards the debt:equity target of 75:25 is slow."

The Board notes MH defends its level of OM&A expenditures on the basis of 'need' and has argued that it has successfully 'controlled OM&A cost per customer account'. The Board is of the view that this premise will remain not fully substantiated, given the enormous amount and percentage of total OM&A costs that have been and are forecast to be capitalized, at least until adequate peer benchmarking has been performed and the results reviewed.

As expressed in past Orders, for two decades MH's annual net income result has been assisted/increased by its deferral and capitalization process. If non – direct construction costs (an allocation of the salary of staff in contracts not involved in actual construction but more in planning in supporting roles) had been expensed in the period incurred, rather than capitalized or deferred, annual net income would have been considerably lower, and possibly negative in many years; OM&A cost per customer account would have been much higher; rate pressure would have been considerably greater than has been demonstrated to date; and retained earnings would be much lower.

As indicated, while there is an argument for MH’s current approach (to expense costs in the current period and reflect them in current rates, when the costs relate to projects not expected to provide benefits until the future, would mean charging the current generation of MH’s customers for costs that could arguably be met by future generations), MH’s rate structure and rates, even including the increases directed and indicated in Order 90/08, is premised on past and future OM&A cost deferrals and capitalization. If the approach was to change (a distinct possibility with the upcoming adoption of IFRS), costs now capitalized in the current period would be expensed. This would, again as previously noted, result in current and future ratepayers being billed for costs reflective not only of current costs but also cost burdens avoided by past ratepayers as a result of the current process of deferral and capitalization.

The Board does not believe OM&A should be adjusted based on the corporate strategic plan target of $640 per customer as suggested by the Coalition. The Board is not convinced the benchmark is completely relevant, given the level of expense deferrals and capitalization impacting the current result. Once more stringent capitalization requirements are put in place with IFRS such a metric may have more value and use in the establishment of rate requirements.

To arbitrarily direct, as some interveners have suggested, that a significant amount of expense not be reflected in rates, as a way of sending a message to

MH that it is spending too much on OM&A, would be irresponsible given what the Board and the recent process has revealed.

This Board must rely on the public GRA process to provide opportunities to assess OM&A, and while the Board continues to express concern, there is nothing on the record sufficiently concrete to justify not accepting the costs in rates.

IFRS

The Board notes the coming adoption of IFRS is likely to have a material impact on MH's financial reporting and results. The Board further notes that AcSB has, in advance of IFRS, established a new reporting standard with respect to accounting for intangible assets [including goodwill, deferred charges and capitalized expenditures].

These new requirements are effective for fiscal years beginning on or after October 1, 2008 and could have an impact on MH's fiscal 2009 - 2010 accounts. However, the Board is aware that MH is looking to U.S. Federal Accounting Standards Board (FASB) accounting standards in support of its continuing its present accounting practices in the short term.

The Board's primary concern is not accounting for the short-term, but the long term, particularly with MH's massive capital expenditure plans.

The Board notes in The FASB Handbook section 71.34 (in part), Accounting for the Effects of Certain Types of Regulation, reads as follows:

> "The regulator's action provides reasonable assurance of the existence of an asset (paragraph 9). Accordingly, the regulated enterprise would capitalize the cost and amortize it over the period during which it will be allowed for rate-making purposes."

The Board notes that interpretation of the above standard, which suggests continuing the current accounting practices of MH until IFRS is in place, will require the continued support of this Board.

Given MH's reliance on a U.S. accounting standard, the question is - if the Board were to develop its own regulated retained earnings, net income and debt:equity ratio approach (ahead of mandatory IFRS adoption), one that is more "conservative" and has the effect reflecting in expenses and rates, more current period expenses, would regulatory accounting, in effect "two sets of books", be in the public interest?

At the hearing, MH's witness Mr. Derksen dismissed changes to rate regulated accounting at this time, noting that the CICA had deferred the matter awaiting a future conversion of Canadian GAAP to IFRS. Under US GAAP, exemptions from normal GAAP for rate regulated utilities depend upon the regulator directing the accounting treatment and are premised on the regulator effectively guaranteeing the utility future cost recovery of expenses then to be deferred through higher rates later on.

If the Board took the position that current capitalization and deferrals should not occur, perhaps reflecting its assessment of IFRS guidelines, MH would lose the ability to defer such items in its accounts, and this would affect total current expenditures, net income and, likely, rates.

The Board remains concerned with the Corporation's ongoing aggressive deferral and capitalization accounting practices, and recommends that MH consider early adoption of IFRS standards. The Board further recommends that the Board's prior concerns as well as its current views as expressed in this Order be brought to the attention of both MH's external auditors and also, its independent consultant to assist the Corporation with its IFRS transition strategy.

In any case, with the reflection of IFRS in its accounts, intangible assets now on MH's books may have to be expensed. .

The Board further notes that MH has not adjusted its current forecast (IFF 07-1, which, as previously reported extends to fiscal 2017/18) to reflect the implications and impact of the new accounting standards. The Board accepts that such an adjustment, at least in a formal final sense, may be premature as the true impact and implications have not yet been resolved. Nonetheless, the Board is concerned with the impact on MH’s financial statement of the transition to IFRS. The Board needs to be made aware of the implications to arise from the adoption of IFRS so as to be in a position to consider its regulatory options relative to the Board's jurisdiction.

Accordingly, the Board will direct MH to provide it a report by February 1, 2009, to be prepared by an independent professional accounting firm.

The Board will require MH to file, by January 15, 2009:

a) A report explaining and quantifying the proposed transition to IFRS.

b) A copy of MH’s consultant’s report indicating the projected impact of the adoption of IFRS on the Utility, specifically with respect to MH's current deferral and capitalization approaches, and as to the likely status of goodwill now recorded in its accounts.

c) An articulation of the new proposed MH accounting policies detailing how they comply with IFRS

d) An explanation of any changes to the internal operations of MH which may be planned or contemplated to offset any increased annual expenses expected as a result of the adoption of IFRS; MH’s and its consultant’s views of the Board’s regulatory options, including a review of the pros and cons of special purpose financial reporting for utilities for rate-setting purposes.

e) Updated IFF and CEF forecasts, covering the years 2008 to 2028, reflecting the expected impact of the new standards and assumptions of related operational changes as may be planned or contemplated by MH.

MIPUG recommended that regulatory accounting be considered as an acceptable deviation from GAAP for rate-setting purposes, following IFRS being implemented and assuming the implementation will have major implications for annual expenses, net income, retained earnings and, quite possibly, future rates.

MIPUG noted that regulatory accounting is prevalent in Ontario, and is a practice followed by OEB. However, the Board further notes that the OEB regulates natural gas utilities and 80 electric distribution companies, with varied ownership structures. In the Board's view, the use of regulated accounting by the OEB may be due more to the fact of the number of electric utilities it regulates and a perceived need to account for results on a consistent basis, rather than a desire by the OEB to depart from GAAP for rate-setting purposes. There is only one electric utility in Manitoba, MH, and it is regulated by this Board.

The Board notes the importance that MH and its financial position, plans and results has in the considerations of debt-rating agencies regularly assessing the financial strength and debt rating of the Province. The financial statements of MH are currently prepared in accordance with GAAP. IFRS will be the new GAAP required by all utilities, including MH. Any deviation from GAAP for rate-setting purposes may not be viewed in a positive light by debt-rating agencies, and a negative view could have negative implications on the credit rating of the Province, potentially limiting the source of capital and increasing the cost of borrowing for both MH and the Province.

Accordingly, the Board currently does not believe that separate regulatory accounting should be considered at this time, an approach that would involve deviating from GAAP and, in a sense, establishing a second set of books for MH rate-setting purposes. The Board further believes that a change to regulatory accounting, even if a case for it is established and found valid by the Board, is premature at this time.

The potential for adopting separate regulatory accounting standards that deviate from GAAP (after the adoption of IFRS) will be considered by the Board only once the Board has more information on the potential impact of the accounting changes on MH arising from IFRS, the implications of adopting regulatory accounting, and the potential implications of staying with GAAP or moving to regulatory accounting for rate-setting for the Utility's customers.

Staffing Levels

MH's personnel complement (measured in EFTs - equivalent full-time positions - and based on hours worked as recorded by MH) has soared since 1999, the first large increase accounted for by the additional staff added to the complement following the purchase of Centra Gas, followed up in 2002 by another major influx of personnel upon the purchase of Winnipeg Hydro (WH).

Even taking into account the additional personnel associated with those purchases, and after acknowledging MH's claims of synergistic savings resulting from one employer of all staff, it remains evident that considerable additional personnel growth also occurred, and this is ahead of the actual start up of construction (other than site preparation and roads at Wuskwatim) of Wuskwatim, Pointe du Bois, etc. (an increase of a few hundred additional personnel relates to new trainee positions associated with the Wuskwatim project).

Staffing levels are projected to further increase as the capital expenditure plan develops and is implemented. That said, and some growth explained, the Board remains of the view that MH should develop enhanced analytical tools to allow for a better understanding of the reasons for staff increases over the years. It is important to understand that staff costs represent the vast majority of OM&A expenses. Such staffing analytical tools should be developed and incorporated in the benchmarking analysis which the Board will direct be undertaken in this Order.

Cost Control Measures

The Board notes that staffing levels (EFT) is an important metric, though only one among others that should be further developed. The Board further notes that while the development of performance benchmarks and metrics has long been established as a performance goal of the Corporation, due to prioritization it, regrettably, is yet to be acted on.

The Board agrees with the Coalition that MH should develop performance benchmarks just as the Corporation has indicated it has planned to do for several years in a succession of corporate strategic plans. Given OM&A expense growth in prior years and forecast for the future, MH should assist GRA proceedings by providing the Board better tools to assess the appropriate level of OM&A for rate-setting.

Accordingly, the Board will direct MH to undertake and file with the Board, by June 30, 2009, an independent benchmarking study of key performance metrics, using the most currently-available data and including:

a) Primary key drivers of OM&A in each operational division [Board preference is to allow for a comparison with a greater number of other utilities].

b) Comparable other Canadian Utility data for each of the drivers.

c) Key comparison indicators including staffing levels.

d) A comparison with and discussion of industry best practices.

e) Potential improvement areas.

The Board expects to be apprised of the scope of the study in advance of it being undertaken, and will anticipate being provided the opportunity to provide direction.

The Board is convinced that both the Province and ratepayers will benefit from the developments of appropriate metrics to assess the reasonableness of the level of current and future OM&A expenses, in advance and particularly because of, the proposed major capital expansion program.

MH’s justification for the level and growth of OM&A expenditures includes an indicated need for increased maintenance and/or replacement of aging capital assets to maintain the safety and integrity of its electrical system. Recently this assertion is difficult for the Board to evaluate, as the Board lacks jurisdiction over MH’s capital expenditures, yet capital expenditures are the major driver of rates.

One item that is lacking is sufficient support for the level of maintenance and upgrades to the existing capital assets of the Corporation. The Board notes Mr. Harper’s suggestion that as a best practice, MH should undertake an Asset Condition Assessment, and his view that such a study will provide information on the degree of degradation of existing assets and the need for rehabilitation and/or replacement of capital assets.

Despite prior cautions from the Board, MH intends to spend, on average, $385 million a year on capital construction through to and including 2017/18, capital expenditures that are not related to major generation and transmission projects, which are accounted for separately. In an effort to better justify and demonstrate the necessity of such normal capital expenditures, the Board agrees with interveners on the need for a periodic Asset Condition Assessment Study.

The Board agrees that a study of this nature, done at reasonable intervals, will assist in evaluating MH's progress in maintaining the electrical system, and should also provide additional support for the level of OM&A being incurred and forecast. The Board believes it's appropriate that MH undertake such a study, and will so direct MH to undertake and file with the Board an Asset Condition Assessment by June 30, 2009, that defines:

a) major assets and categories of assets;

b) the estimated remaining economic life of each major asset and category of asset;

c) an indication of the implications for OM&A costs related to maintaining required and scheduled maintenance;

d) a listing of scheduled, planned or anticipated major upgrading/decommissioning of major assets and/or categories of assets;

e) forecast expenditures for planned renovations and/or replacements with respect to now-available energy supply and transmission; and

f) Dam Safety Condition Assessment and Maintenance requirements.

In advance of the commencement of the Asset Condition Assessment Study, MH is to file with the Board detailed Terms of Reference containing the scope for undertaking such a study and a definition of the resources to be employed, on or before January 15, 2009.

New Head Office

With respect to MH's head office project, which is currently expected to involve capital expenditures in the range of $280 million (approximately 1/5th of the Corporation's retained earnings), the Board remains concerned that MH's savings from operating synergies and abandoned current leases may not develop sufficient overall savings to avoid a rate impact arising from the project.

MH suggested that there would be no increase in rates to pay for the new corporate head office, and that the Corporation expects the financial benefits of productivity improvements, and lapsed lease payment requirements, to offset the approximate $20 million of annual additional costs associated with its new building.

The Board has heard MH suggest it will target headcount (EFT) reductions and lease lapses to help offset the increased costs expected to arise with the new head office (depreciation, property and capital taxes, interest, operating costs, etc.), but also heard doubts expressed as to whether such savings would fully materialize.

The Board will direct MH to file a report with the Board by June 30, 2009, detailing the final all-inclusive capital cost of the corporate head office project including such things as construction cost, furniture and equipment, telecommunications, equipment leases and the contemplated or planned operating actions to recover incremental costs related to the new head office. The Board reaffirms that no additional incremental costs are to accrue or be allocated to Centra as a result of the new MH head office.

The Board reminds MH that the Corporation has already been directed by the Board, through an Order arising out of a Centra GRA proceeding, that no additional costs are to accrue or be allocated to Centra as a result of the new head office. The head office came about as a condition of MH's purchase of WH; it had nothing to do with Centra.

6.0 Depreciation & Amortization

6.1 General

Depreciation and amortization expense was $276 million in fiscal 2003/04, rose to $314 million in fiscal 2006/07, and is forecast to further increase to $332 million for fiscal 2007/08 and $347 million for fiscal 2008/09.

MH attributed $6.5 million of the $18 million increase expected in fiscal 2007/08 (from fiscal 2006/07) to new depreciation rates, while the balance was attributed to normal amortization on increased capital assets.

MH instituted new depreciation/amortization tables as of April 1, 2007, flowing from a study that resulted in a forecast annual overall 2.2% increase in depreciation/amortization expense. The new study replaces the previous study that was undertaken in 2002; MH updates its depreciation/amortization studies every five years.

At the GRA, MH advised that it had revised the annual depreciation rate for the Pointe du Bois Generating Station from 1.94% to 11.65% to allow for the full amortization of the unamortized capital cost of the existing and old generating station over its estimated remaining life of nine years (a new generating station is planned to be constructed on the site, one with a higher capacity). As a result, the annual depreciation expense related to the existing facility increased by $1.9 million annually. MH plans on decommissioning the existing generating station effective March 31, 2015.

Depreciation and amortization is forecast to grow to $453 million by 2017/18, due to planned major increases in capital assets.

6.2 Board Findings

The Board agrees with the new depreciation rates, including the acceleration of the depreciation of Pointe du Bois to recognize that the existing asset is to be decommissioned and replaced. However, the Pointe du Bois upgrade and forecast work on the Slave Falls G.S., coming relatively shortly after the purchase of WH, raises a question as to the adequacy of present depreciation and amortization rates in use for the other generating, transmission and distribution assets acquired when WH was purchased, notwithstanding the five year review of such rates.

The Board further notes the provincial plan for curtailing Brandon Coal Plant generation [MH has estimated reducing the use of the plant to emergencies only will reduce its annual net income forecasts by $10 to $20 million dollars]. When the IFF is updated to reflect IFRS and other changes and issues raised in this Order, the decision to reduce the output of the Brandon Coal Plant should be reflected. And, if there is a decision to close the plant, this asset should be subject to an accelerated depreciation similar to that now in place for Pointe du Bois.

Accordingly, the Board will require MH to file a report by January 15, 2009 with the Board, indicating whether the current depreciation rates for the Generation, Transmission, Distribution and other assets purchased from Winnipeg Hydro, including Slave Falls, and the Brandon Coal Plant remain appropriate and the related proposed capital replacement, expansion and decommissioning costs.

The accelerated write-off of the existing Pointe du Bois facility also brings into question the price paid for Winnipeg Hydro, a price that also included a requirement to build the new head office, the cost of which is now roughly four times the original “placemarker” for the project reported by MH at the 2004 GRA.

The Board has concerns with the planned growth in capital expenditures and the related forecast increases in depreciation and finance expense, and comments further on this topic in other sections of this Order.

7.0 Payments to the Province

As a Crown Corporation, MH is not subject to corporate income tax, and it is neutral as to the federal Goods and Services Tax (GST), since GST paid for its purchases are refunded. While these exceptions are of considerable value to the Corporation, and, by extension, to its customers, MH does pay the Provincial Retail Sales Tax on its purchases, and, as well the Corporation Capital Tax, a tax that is to be deleted for private companies. The Province of Manitoba also levies a number of other fees on MH.

At the 2004 GRA, reported annual payments made to the Province from MH for fiscal 2003/04 were $175 million. The aggregate payment increased to $219 million in fiscal 2006/07 and was forecast to increase further to $230 million in 2007/08 and $223 million in 2008/09.

Total payments to the Province either made or forecast to be made from 2002/03 through 2008/09 are summarized as follows:

Payments to the Province ($millions)

	Actual					IFF 07-1	
Fiscal Year	2003	2004	2005	2006	2007	2008	2009
Corporation Capital Tax	33	35	35	36	37	38	40
Payroll Tax	6	6	7	7	8	8	8
Water Rentals	95	62	104	124	106	114	103
Debt Guarantee Fee	70	67	68	66	68	70	71
Sinking Fund Admin Fee	1	1	1	1	-	-	1
Special Payment	200	4	-	-	-	-	-
Total Payments	**405**	**175**	**215**	**234**	**219**	**230**	**223**
Retained Earnings	1135	707	845	1,265	1,386	1,650	1,774
Retained Earnings including Payments to the Province [1]	1,540	882	1,060	1,499	1,605	1,880	1,997
Total Payments as a % of Retained Earnings - Return to Shareholder[2]	28.8%	14.5%	22.1%	18.3%	14.1%	12.2%	11.2%
Total Payments as a Percentage of Gross Revenue	30.3%	13.6%	14.3%	12.8%	13.4%	13.8%	13.9%

Note 1. Approximates what retained earnings would have been at the end of the year if no payments to the Province were made.

Note 2. The Return to Shareholder is based on the payments to the Province over average Retained Earnings in each year (including the 2003 and 2004 special payments to the Province)

Overall, MH's payments to the Province have represented, excepting for 2003, a return on overall electricity sales to the shareholder in the range of 14%. While the concept of summary budgets results in the net income of MH also being recognized as income for the Province, that income is not available to the Province for its departmental spending unless paid in the form of a fee or dividend. Previously, this Board has recommended that no dividends be paid by MH to the Province until such time as MH has achieved and is expected to hold to its 75:25 debt:equity ratio target.

While MH pays Corporation Capital Tax to the Province based on its invested capital, which is a function of the level of capital employed, both debt and equity, Corporation Capital Tax is being phased out for all private corporations at the end of 2010. MH will remain subject to Capital Tax beyond 2010.

Water rentals relate to the use of provincial water resources, and the fees are paid to the Province on a monthly basis based on hydraulic generation. When, about a decade ago, MH was transferred certain northern liabilities of the Province, water rental rates were frozen to 2001.

The Provincial Debt Guarantee Fee is 1.0 % of the sum of MH bonds, provincial advances to MH and provincial short-term debt outstanding related to MH at MH's year-end. The fee was increased from 0.95% to 1.0% effective for fiscal 2006/07, and the level remains unchanged in MH's forecast for the full forecast period of IFF07-1. The Sinking Fund Service Charge is 0.075% of the amount of the sinking fund balance, and is paid to the Province for its managing of MH's sinking fund investments. MH's sinking fund is a covenant related to its bond issues.

A now expired legislative amendment to the MH Act provided for a special payment to the Province (dividend), which was made through a first instalment of

$200 million in 2002/03, followed by a remaining instalment of $4 million in 2003/04. For the purpose of comparison, dividends are regularly paid, and on an annual basis, by Hydro Quebec and B.C. Hydro to their respective provincial government owners.

The Province recently announced an intention to introduce new carbon legislation towards reducing Green House Gas emissions (GHG) in the province. MH stated that if it continued to operate the Brandon coal generating station at current production levels, the cost of the expected emissions tax on coal would be in the order of $5 to $6.5 million per year, commencing in 2011. However, it is expected that the generating station will, in the near future, be operated under very restricted conditions (for emergencies), which would reduce the emissions tax considerably. Nonetheless, the loss of the current level of average annual coal generation is forecast by MH to be $10 to $20 million annually – the operation of the plant has been profitable for the Corporation.

In addition to the payments to the Province, MH makes Grants in Lieu of Taxes (GILT) to municipalities with respect to MH buildings and structures that are located throughout the Province. In 2006/07, MH made $10 million in GILT payments, and the payments were forecast to increase to $15 million in 2008/09, the increase primarily the result of the new Corporate Head Office being added to Winnipeg's tax rolls. MH is currently negotiating with the City of Winnipeg and has estimated the annual property and business tax bill for its new head office will be in the range of $5 to $7 million dollars, the full effect to occur from 2009/10.

7.0 Payments to the Province

7.1 Interveners' Position

The Coalition noted that the special payment to the province of $204 million then-increased the debt to equity ratio by 3% and the debt component to 85% vs. 82%. By MIPUG's calculation, for 2008/09, the impact of the earlier payment remains at three percentage points.

The Coalition noted that payments to the province represent a significant benefit to the province.

7.2 Board Findings

The Board accepts that the projected payments to the Province represent a return to the Province of approximately 14% per annum of MH's overall electricity revenues. The Board understands that the Province employs these receipts to support health, education, social and other programs, for the benefit of all Manitobans.

MH is a prominent contributor to the overall economic well being of the Province, assisting in a variety of ways:

- Annual payments in excess of $200 million for water rentals debt guarantee fees, payroll taxes, capital taxes and other miscellaneous fees;
- Sales taxes, personal and corporate tax revenues with respect to staff and contractor complements and activities;
- MH's Annual net income, (projected to average $161 million per annum through 2017-18), which is included in the overall accounts of the Province;

- Mitigation payments to First Nations and Northern Communities related to the northern flood agreement and related pacts, amounting to in excess of $600 million on a cumulative basis, which has greatly assisted northern First Nations communities;
- Partnership agreement with NCN with respect to the Wuskwatim G.S. development, and potential pending relationships with other First Nations with respect to Conawapa and Keeyask;
- Targeted training and employment of northern and first nations residents;
- Grants in lieu of taxes payments to Manitoba's municipalities ;
- DSM expenditures towards the environmental objectives of the Province;
- Investment in wind generation, furthering provincial environmental objectives and rural community development;
- DSM low-income programs, to assist in sustaining low-income households;
- Planning for Bipole III to be constructed on the west side of the Province rather on the east side of Lake Winnipeg, to support the Province: object of protecting the boreal forest;
- Uniform rate design, (all communities and customers on the provincial electricity grid are subject to the same rate schedule, assisting with the economic and social development of rural and northern communities); and
- Export/import arrangements with American utilities within the MISO market and the provincial utilities of Ontario and Saskatchewan, which assist in increasing electrical reliability and the overall reduction of GHG emissions.

A further benefit to the City of Winnipeg has been the building of a new Corporate Head Office in downtown Winnipeg, a component of MH's agreement to purchase Winnipeg Hydro. The new head office will result in approximately 2,000 MH employees relocating to the new head office and contributing economically to local businesses and the further revitalization of the Winnipeg downtown.

The acquisition of Winnipeg Hydro has also provided the City of Winnipeg with an ongoing stream of revenue as a component of the sale agreement and saved the City and its ratepayers from the otherwise required massive expenditures to upgrade and maintain aging WH assets, such as Pointe du Bois G.S. Finally, with respect to the benefits provided to the City of Winnipeg, MH has expended over $13 million to upgrade the energy efficiency of the City's operations, the result to have an ongoing and substantial benefit to the City.

8.0 Financial Targets

8.1 Background

In September 1995, MH adopted the following financial targets, which were subsequently reviewed by this Board at the 2002 Status Update Hearing and, most recently, at the 2004 General Rate Application.

MH's current financial targets are as follows:

1. To achieve and maintain a minimum debt to equity ratio target of 75:25;
2. To achieve and maintain an annual gross interest coverage ratio of 1.20 annually; and
3. To fund all new capital construction requirements, except major new generation and/or major new transmission facilities (which include the new head office), from internal sources.

MH's financial targets have varied over the years, due to changing circumstances and priorities. Financial targets have been as follows:

Year	**Financial Target**
1995	75:25 debt equity ratio by 2005/06, interest coverage ratio of 1.20 to 1.35 and fund all capital expenditures, except major new generation and transmission facilities, from internally-generated funds
2001	75:25 debt equity ratio by 2005/06, minimum interest coverage ratio of 1.20 and fund all capital expenditures, except major new generation and transmission facilities, from internally-generated funds
2002	75:25 debt equity ratio by 2011/12, minimum interest coverage ratio of 1.10 and fund all capital expenditures, except major new generation and transmission facilities, from internally-generated funds
2007	75:25 debt equity ratio by 2011/12, minimum interest coverage ratio of 1.20 and fund all capital expenditures, except major new generation and transmission facilities and new head office building and DSM, from internally-generated funds

In 1995, MH moved to more aggressive financial targets to achieve a balance between fiscal responsibility, competitive positioning and customer bill affordability. MH expected that attaining the updated targets would result in lower debt, thereby reducing interest costs and ultimately assisting in rate restraint and competitiveness.

As at March 31, 2002, MH had a debt:equity ratio of 77:23, and appeared well on its way to meeting the 75:25 target. While the dividend to the Province represented an addition of 3 points to the debt element, the target was largely missed as a result of the 2003/04 drought.

The drought resulted in an approximate $600 million reduction to net export revenues relative to a normal flow period, and this, coupled with the $204 million special payment to the Province (planned and implemented before the drought), increased the debt ratio 10 percentage points in two years, severely impeding MH's progress toward its financial target.

Subsequently, the target year to reach a 75:25 debt equity ratio was changed from 2005/06 to 2011/12 to allow for a more gradual rate impact on customers. Since then, with major new capital construction in process and planned, requiring extensive new borrowings, there is no current expectation for the target to be met.

8.2 Debt to Equity

The debt to equity ratio measures the relationship of long and short-term debt (less short-term investments and sinking fund investments) to equity. The ratio is used by bond rating agencies and the Board, among others, to assess the financial risk MH represents.

Subsequent to reviewing the level of debt issued by the Corporation in relation to the amount of equity held in the form of retained earnings, there is no expectation that the Province will make equity injections into the Corporation; it is to manage its affairs such as to avoid such a requirement. MH established a debt to equity ratio target of 75:25.

MH's actual and forecast debt to equity ratios for fiscal 2003/4 to 2008/09, as compared to the forecasts of IFF03-1 presented at the last GRA, were and are as follows:

Debt to Equity Ratio Comparison Actual/IFF07-1 to IFF03-1

	Actual				Forecast	
Fiscal Year	2004	2005	2006	2007	2008	2009
Actual/IFF07-1	87:13	85:15	81:19	80:20	77:23	77:23
IFF03-1	85:15	85:15	86:14	86:14	87:13	87:13

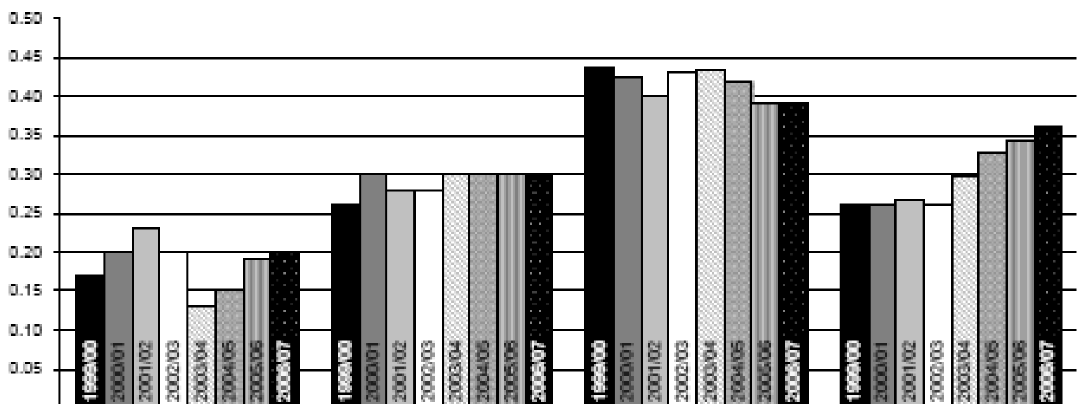
MH has made a marked improvement in its movement towards the 75:25 debt to equity ratio target since the 2003/04 drought. The Corporation's improved financial position relates to higher than expected extra-provincial revenue in fiscal 2005/06 and 2007/08, and rate increases granted by the Board in 2004 (5%), 2005 (2.25%), 2.25% (granted on an interim basis April 1, 2007 and finalized by Order 90/08), and 5% as of July 1, 2008 (Order 90/08). The 5% increase granted July 1, 2008 (Order 90/08) should assist.

8.0 Financial Targets

At the recent hearing, MH stated that its proposed 2.9% rate increase would assist MH in pursuing its debt:equity target, while being sensitive to the impact that electricity rate increases have on customers. The Corporation advised that it did not expect to reach the target debt to equity ratio within its latest long-term forecast period, that is, through 2017/18.

Compared to other Canadian utilities, MH has a higher debt to equity ratio:

Equity Ratios Comparison to Other Utilities



	Manitoba Hydro (Mar 31)	BC Hydro (Mar 31)	SaskPower (Dec 31)	Hydro-Quebec (Dec 31)
■ 1999/00	0.17	0.26	0.44	0.26
■ 2000/01	0.20	0.30	0.43	0.26
□ 2001/02	0.23	0.28	0.40	0.27
□ 2002/03	0.20	0.28	0.43	0.26
□ 2003/04	0.13	0.30	0.44	0.30
■ 2004/05	0.15	0.30	0.42	0.33
■ 2005/06	0.19	0.30	0.39	0.34
■ 2006/07	0.20	0.30	0.39	0.36

MH's current forecast IFF07-1 does not foresee MH meeting its 75:25 debt to equity target, neither by 2011/12 nor over the remainder of the IFF07-1 forecast period to March 31, 2018. MH forecasts a debt to equity ratio of 77:23 in fiscal 2017/18, the same as forecasted for fiscal 2007/08, even with cumulative rate increases of 33% assumed over the forecast period.

MH indicated in addition to the 2.9% rate increase it was seeking at the recent GRA, that (hypothetically) consecutive increases of 6.60% in fiscal years 2010, 2011 and 2012 would be required to reach the debt to equity ratio target of 75:25 by fiscal 2011/12.

Achievement of the 75:25 debt to equity target without larger rate increases appears to be virtually impossible due to the planned major increases for capital spending initiatives on New Generation, Major Transmission and the new office building, because of the corresponding increased debt levels to fund such construction.

As well, there is an increasing statistical probability that a new drought will set the Corporation back, and the losses from a serious drought could more than eliminate the current retained earnings balance. Other risks, including currency, interest rates, accounting standards changes, increased domestic loads and higher than now-projected capital expenditures also increase MH's risk status.

As suggested, changes in GAAP to come with the move to IFRS in fiscal 2011 can be expected to further hinder MH's progress to its debt to equity target, if not place even more pressure on rates going forward. A discussion of the IFRS changes is provided in other sections of this Order. As in previous Orders, the Board questions MH's cost deferral and capitalization practices which now have the effect of increasing annual net income and retained earnings and assisting in progress towards the stated debt:equity ratio.

8.3 Interest Coverage Ratio

The Interest Coverage Ratio is calculated to measure the degree to which net income before interest exceeds finance expense. MH's interest coverage ratios, actual or projected, for 2003/04 to 2008/09 are as follows:

Interest Coverage Ratio Comparison Actual/IFF07-1 to IFF03-1

	Actual				**Forecast**	
Fiscal Year	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**
Actual/IFF07-1	0.12	1.27	1.83	1.24	1.56	1.30
IFF03-1	0.29	1.08	1.05	1.05	1.03	1.04

The improved interest coverage ratio, relative to IFF03-1's actual and forecast, is due to higher than forecast net income and lower interest costs than forecast in IFF03-1. The actual ratio for fiscal 2003/04 was due to the drought and the loss incurred in that year. In the current IFF07-1, the interest coverage ratio target is achieved in all years of the forecast except for minor shortfalls from fiscal 2010 to 2014.

Again, achievement of the target in recent years has been assisted by MH's cost deferral and capitalization practices, which will change with IFRS. And, of course, there are the myriad of other risks that could lower annual net income and put the achievement of this target at risk.

8.4 Capital Coverage

The Capital Coverage, as formally stated, measures MH's ability to make "normal" non-major capital purchases without taking on additional borrowings. MH's actual or projected capital coverage ratios for 2003/04 to 2008/09 are:

	Actual				**Forecast**	
Fiscal Year	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**
Actual/IFF07-1	(0.42)	1.20	2.52	1.12	1.74	1.07
IFF03-1	(0.21)	0.54	0.50	0.41	0.48	0.56

Again, the actual results for fiscal 2003/04 were due to the drought, and the improved results since to improved water flow conditions and resultant higher exports, and with the continued exception of capital spending on major projects from inclusion in calculating the ratio.

MH's current practice is to exclude major capital expenditures when determining the capital coverage ratio. When major capital expenditures are included, the resultant capital coverage ratio indicates that MH must finance its major capital expenditures with debt, as opposed to the intended internally-generated cash flows.

8.0 Financial Targets

Comparison of MH Capital Coverage Including Major Capital:

	Actual				Forecast	
Fiscal Year	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**
Actual/IFF07-1	(0.42)	1.20	2.52	1.12	1.74	1.07
Including Major Capital and Head Office	(0.35)	0.86	1.64	0.70	0.58	0.34

Comparison of MH Capital Coverage Including Major Capital IFF07-1:

Fiscal Year	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Actual/1FF07-1	1.74	1.07	0.69	0.76	0.84	1.13	1.03	1.1	1.22	1.21	1.40
Including Major Capital and Head Office	0.58	0.34	0.3	0.34	0.41	0.46	0.29	0.31	0.31	0.28	0.36

As previously indicated, the deterioration in the capital coverage ratio in 2003/04 was due to the drought; it led to MH's largest and a very major loss. The improvement since 2003/04, relative to the forecast in IFF03-1, is related to higher than forecast income due to excellent water conditions, providing for higher than expected export revenue, and a succession of Board-approved rate increases.

MH's capital coverage is forecast to decline in 2008/09 from that forecast for 2007/08 due to increases in capital spending. In the current IFF07-1, the target is met in all years except fiscal 2010 to 2012, those missed target years being due to increases in capital spending on new generation and major transmission projects.

Again, IFRS and the myriad of other risks faced operationally and financially by MH could reduce the net income now forecast for future years and further worsen the capital coverage ratios.

8.5 Reserves

The concept of MH establishing specifically defined reserves to meet risks associated with a drought or another calamity was suggested by MIPUG's witnesses.

The suggestion was that a reserve fund would be established out of retained earnings and future net income and, when deemed adequate, would be utilized to avoid what otherwise might be judged "excessive" rate increases, which, in the absence of adequate reserves, could be required.

With an adequate reserve in place, annual rate changes would be decided based on a judgment as to the sufficiency of the reserve funds in place to meet the risks of the Corporation, utilizing net income to build the fund during normal years and providing for a gradual recovery of a depleted reserve following a calamity that had resulted in the use of the reserve to prevent an "excessive" rate increase.

If MIPUG witnesses' advice and the intervener's recommendation was taken and such a reserve or reserves established, this approach would supplant the current reliance on retained earnings and the now-required or goal of meeting the 75:25 debt to equity target (as the means to avoid "excessive" rate increases driven by a calamity).

MH did not agree that a specific rate-protection reserve or reserves should be established, and considered the idea of segmented or restricted reserves to represent an outdated concept, and one abandoned by MH in 1992. Specific purpose reserves would, for Hydro, be inconsistent with contemporary principles of Enterprise Risk Management, in which the interdependence of risks is to be managed in a coordinated way across the Corporation.

In short, MH prefers to keep the 75:25 debt to equity ratio as its target "buffer" against all financial risks, and to forego the development of specific reserves to meet specific risks.

8.6 Interveners' Positions

Coalition

Mr. Harper opined that MH established a target debt to equity ratio for two primary reasons: first, to demonstrate to the financial community that MH is a financially sound Corporation (important because the perception of MH's financial integrity in the financial community affects the borrowing rate not only for MH but also for the Province of Manitoba, which guarantees the Corporation's debt), and the second, that maintaining a satisfactory level of equity provides a means of stabilizing rates under particularly adverse events such as a drought.

In meeting the financial impact of a drought (which brings losses and increased debt to equity ratios) what is important for Mr. Harper is the overall level of retained earnings and how it compares with the level of losses that might occur under various types of adverse events.

Establishing an appropriate level of reserves within this context involves more than estimating the cost of a five-year drought. Mr. Harper stated that more work needs to be done to assess MH's risks if the Board wants to establish an appropriate target reserve, even if the reserve is to continue to be expressed as retained earnings.

Mr. Harper stated that a proper determination of an appropriate level of reserves for MH would entail:

- Identification and quantification of the risks faced by MH;
- Identification of ways to manage these risks and, in particular, identification of those risks that would be managed through maintaining financial reserves as opposed to other approaches such as insurance, financial hedges and rate increases;
- A determination of the likelihood of occurrence of the various risks that are to be managed through reserves, and the extent to which individual risks are either independent or interdependent;
- A determination of the degree of a risk MH is willing to accept; and
- A quantification of the resulting reserves required.

Mr. Harper noted that the development of an appropriate reserve target should be an iterative process, as the degree of risk MH is willing to accept is dependent upon the level of reserves required and the cost of achieving such reserves, the cost being measured in the magnitude of possible rate increases.

Mr. Harper stated that forecast capital spending in 2007/08 and 2008/09 is considerably higher than historic averages, mainly due to expected higher spending on New Generation and Transmission, and noted that this spending is putting noticeable pressure on MH's debt to equity ratio. As of March 31, 2007, spending on major new generation and transmission projects was estimated to have increased the debt ratio by 2%, and by March 31, 2009, 5%.

MIPUG

MH's total capital – debt plus equity - is the denominator in the debt: equity ratio, and is expected to increase massively as the planned major new projects proceed. With domestic load expected to continue to increase, average export sales volumes can be expected to decline until new generation comes on stream. And, when new generation does come on stream, MIPUG noted that the experience has been that each new plant experiences a few years of marginal or loss years, placing pressure on annual net income levels and the debt to equity ratio during those years.

Thus, and for MIPUG, in the absence of annual and material domestic rate increases the current debt to equity target of 75:25 should not be expected to be reached in the foreseeable future, that is for more than a decade. Hence the problem, assuming the debt:equity target ratio of 75:25 is important and required to be met. If the target ratio is to be met, for MIPUG, ratepayers should expect annual rate increases, the only question being the magnitude of the increases.

To a large degree, the magnitude of the needed increases is, as MIPUG stated, necessarily related to major new capital projects and the new debt taken on to allow those plans to be realized. MIPUG thus linked future rate increases with projects to be advanced earlier than needed for domestic purposes, i.e. for export reasons, and claims that such rate increases would be contrary to "clear policy objectives" for these projects.

As such, for MIPUG, the debt:equity target (even if accepted as a valid target for assuring the Corporation's Board of Directors) is much too coarse to use as an analytical tool for the purposes of setting rate levels.

With the potential for further billions of dollars for additional capital projects in the years following the current IFF horizon, bringing debt up to, say, $20 billion by 2022, for MIPUG it is apparent that a 75:25 debt to equity ratio could only be achieved with unprecedented additions to net income by way of rate increases on top of the forecasts contained in IFF 07-1.

As to how much additional net income would be required to allow retained earnings to increase sufficiently to attain and hold to a 75:25 debt:equity ratio, MIPUG asserted up to an additional $2.5 billion in additional net income would be required, depending on the level of capital expenditures, above and beyond the net income forecast to come from annual 2.9% rate increases and net export revenues as currently forecast.

Reserves are required for the goal of protecting ratepayers from the risk of large rate increases driven by the actuality of a major risk. MIPUG's witnesses opined that MH's projected levels of retained earnings will be ineffective for this purpose, as the level of retained earnings is not directly overseen by this Board and does not provide the Board with a sufficient level of control.

MIPUG recommended that the Board should establish a reserve to cushion ratepayers from rate increases due to the risks faced by the Corporation, and discard further reliance on the debt:equity target ratio. And, per MIPUG, ahead of establishing the reserve to be required, the Board should direct that a major review of alternatives to the establishing of appropriate reserves be undertaken, as may be permitted within the appropriate legislation.

MIPUG urged the Board to consider the need for a focused debate on issues and options regarding establishing secure reserves. In such a review, consideration should, for MIPUG, extend to the determination of the appropriate levels of these reserves, alternatives for maintaining the reserves fully under the Board's jurisdiction and oversight, and, as well, measures for calculating, in any given year, the necessary level of appropriation to or withdrawal from, the reserve accounts – to affect the rate increase to follow.

8.7 Board Findings

Notwithstanding MIPUG's concerns and the hypothetical value the intervener claims for leaving the current method of determining the adequacy of MH's reserves, i.e. reliance on a debt to equity target, for specific reserves, the Board remains concerned that MH is not making sufficient progress in meeting and assuring holding to maintaining its current debt to equity target once met.

The Board is further concerned that during particular fiscal periods of the current forecast to and including fiscal 2017/18, MH does not expect to maintain either or both of its other financial stability targets, that being its interest and capital coverage ratio targets. The three measures of financial health and stability (debt to equity, interest coverage and capital coverage) are taken seriously by debt rating agencies and others, and while the ratios may not be expected to be maintained throughout the whole forecast period due to the effects of the expanded capital program, they still remain important.

Financial targets are set to be met, and to secure the future financial integrity of the Corporation MH also must, logically, take into account the upcoming adoption of IFRS, the possible future effects of continuing if not increased Canadian dollar appreciation and rising interest rates, and the rising cost of constructing new assets. The Board suggests MH consult with bond-rating agencies and government over what would represent an acceptable deviation from the existing financial stability targets during periods of considerable capital expansion, all to be financed by debt and rates.

The Board further notes that, cumulatively to March 31, 2009, and including the 5% established by Order 90/08 from July 1, 2008, approximately $400 million of additional revenue will have been generated from recent (since 2004) rate increases, following a decade of no domestic rate increases. However, despite these revenues and the on-going effect of these rate increases, with its current capital program plan and with ongoing increases in OM&A expenses, MH still does not expect to meet its debt to equity target within the current forecast period ending March 31, 2018.

The Board understands an argument can be made that current rate increases are due to capital expenses advanced for export purposes ahead of domestic load need, and that this may be considered to involve a degree of inter-generational inequity. However, the Board finds it unreasonable to expect current ratepayers to avoid any rate implications of plans now being made and implemented that contain not only opportunity but also increased risk for future generations.

The Board observes that this current generation of ratepayers may reasonably expect to gain from the economic activity associated with the Corporation's current capital plans, even ahead of those plans yielding any new export or domestic generation sales, and seeks a balance of interests.

That said, MH needs to provide the Board more assurance, through more detailed analyses and external assessments, that the risks now being taken on are reasonable and that the intended new projects will benefit not only current generations but future ones as well.

The Board notes that MH has a growing and significant level of non-revenue producing assets (intangible assets, such as deferred charges, goodwill and capitalized OM&A expenditures, the new head office building; and construction in progress, which includes large accumulations of capitalized OM&A). MH's current and forecast Retained Earnings through to 2017/18 is fully accounted for by these non-revenue producing assets, bringing into question the adequacy of a 75:25 debt:equity target with the current accounting approach - and this does not include reflection of IFRS.

The Board notes recent major export contracts being entered into since the filing of the GRA, though briefly reported on during the proceeding, are expected to require additional generation and transmission not yet included in the Corporation's capital expenditure forecast, projects that will push MH's debt closer to $20 billion by 2022 (assuming the forecast of the cost of these projects does not further increase materially).

It is the Board's view that, given the ambitious capital program and related increasing growth in debt, it is unrealistic to anticipate that MH will meet its debt to equity ratio of 75:25 even by the end of the current forecast period, 2017/18. Such a target has become seemingly impossible to attain given that the major capital expenditures contemplated are to be financed by debt, without truly significant rate increases.

The Board notes the Coalition's inference that Hydro's debt:equity ratio could be 80:20, and that such a change would be without risk as such a ratio is comparable to B.C. Hydro's new government-set target. However, BC Hydro does not have the same approach for deferral of expenditures as MH, and may not have the same OM&A capitalization policy as well. Furthermore, while BC Hydro’s total long-term debt may be similar to MH’s, BC Hydro has an annual revenue stream that is almost three times that of MH, providing a greater ability to service debt.

Furthermore, the degree to which B.C. government's debt ratings are dependent on B.C. Hydro is considerably less than the case with MH and Manitoba. It is the Board’s understanding that rating agencies look prominently at MH’s financial strength in assessing the credit rating of the Province. A weakening of the financial strength of MH would not be viewed favourably by those credit rating agencies and may have implications impacting the credit rating of the Province, making provincial borrowing more expensive. Such a development would not be in the pubic interest.

It is the Board's understanding that private utilities would have difficulty raising debt with a debt:equity ratio greater than 60:40, and that new projects would proceed only with the assumption of injections of additional capital. In MH’s case, the assumption is that retained earnings represent the Utility’s capital and that capital increases only by means of net income, derived from domestic rates and export profits.

If the Board were to implement, at least for rate regulation purposes, the Rate Stabilization Reserve model (RSR) proposed by MIPUG, it would be expected to deem certain earnings to contribute to the RSR while "unapproved" costs would "fall back" to MH and its sole shareholder, the Province. Under MIPUG’s suggested approach, if the Province did not reimburse MH directly for such “unapproved costs”, the Utility would be further at risk of missing vital financial targets.

As to MH's opposition to the RSR proposed by MIPUG, it is only partially valid. Put in the proper context, the RSR could be restricted only in the sense that it could only be used for identified operating "disaster" conditions. Under such an approach, deemed excess spending would not be reflected in rates by the Board, and would fall to the shareholder through the unrestricted retained earnings balance. However, if the Board were to adopt such an approach, a process would need to be developed to determine an appropriate level of the RSR.

What would represent an adequate RSR? Previously, the Board has requested that MH file a quantified analysis of its major risks and analysis that would put numbers to the major risks that have been identified. Not only would the risks associated with a five-year drought be quantified (MH has suggested that such a drought could result in losses of over $3 billion), but also the risks associated with the failure of major infrastructure, interest rate increases, further currency changes and, for any reason, the loss, even if temporary and for whatever reason, of the export market. In the absence of much more rigorous analysis, the Board is uncertain whether such an analysis would arrive at a RSR lower or higher than the current level of retained earnings required under a 75: 25 debt to equity target. The Board is concerned that there may be a case for establishing a higher reserve requirement, one that would further push rates.

On balance, the Board is of the view that a regulated RSR, i.e. the adoption of MIPUG's specific reserve proposal, is currently premature, at least ahead of MH identifying and properly quantifying its risks, as has been requested in past orders. Such quantification is vitally important given the increased risks that will accompany a debt level that may reach $20 billion by 2022.

Given the increase in capital spending, and recognizing MH no longer forecasts achievement (by 2012 or even 2018 for that matter); a 75:25 debt:equity ratio, it is time for MH to re-evaluate the equity target and set a new date for achievement.

Accordingly, the Board will require of MH a detailed, comprehensive and quantified Risk Review. The Board will withhold its final judgment on the development of reserves designed to meet the risks faced by MH until such a review has been placed before it and reviewed at a subsequent GRA. At least until then, the current financial targets stand.

.

9.0 Capital Expenditures

9.1 General

MH's CEF 07-1 is a projection of MH's capital expenditures for new and replacement facilities to meet the electricity requirements in Manitoba, as well as expenditures to meet firm sales commitments outside the Province.

CEF 07-1 summarizes an eleven-year program of capital expenditures totalling $11.3 Billion to fiscal 2018, ranging from $831 Million in fiscal 2008 and increasing to $1.1 billion in fiscal 2018. Spending for New Generation, Transmission (and the New Head Office) total $7.5 billion, with the balance of $3.8 billion representing an ongoing capital program of, on average, $345 million per year. This represents a ten-year increase of $930 million in anticipated new capital costs, from that previously forecast in CEF 06-1.

New Generation and Major Transmission forecast in CEF07-1 was:

New Generation & Major Transmission Capital Expenditures CEF07-1 ($ millions)

Fiscal year	Project Cost	2008	2009	2010	Culmulative to 2018
Wuskwatim Generating Station	1,274.6	147.1	287.4	293.9	1,080.4
Wuskwatim Tansmission	319.8	79.2	107.9	47.1	280.0
Keeyask Generating Station Licencii	325.3	50.5	63.4	-	113.9
Conawapa Generating Station	4,978.4	32.6	57.8	54.7	2,162.1
Kelsey Improvements/Upgrades	183.9	36.1	30.6	28.4	123.0
Point du Bois Rebuild	900.5	13.5	23.3	35.0	896.0
Bipole III Western Route	2,447.8	1.9	2.9	9.3	2,237.0
Other	305.0	7.3	13.6	46.2	253.5
Demand Side Management		40.4	43.1	34.2	338.4
Total		408.6	630.0	548.8	7,484.3

9.2 Comparison of CEF03-1 to CEF07-1

At the 2004 GRA, MH filed CEF 03-1, which reflected capital spending of $5.8 billion over the eleven-year period from 2003/04 to 2013/14. Over the same eleven-year period, MH's actual capital expenditures for 2003/04 to 2006/07 and projected expenditures for 2007/08 through 2013/14 is now forecast at $8.5 billion, $2.7 billion greater than that forecast in CEF 03-1, as illustrated in the following table:

Capital Expenditures ($millions)

	Actual				Forecast				11-Year
Fiscal Year	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011-14**	**Total**
Actual/CEF07-1	455	485	504	634	801	1,016	958	3,648	8,502
CEF03-1	481	583	622	748	748	641	598	1,405	5,826
Difference	(26)	(98)	(118)	(115)	53	375	360	2,244	2,676

The major increase since 2004 is attributable to additional new Major Generation and Transmission, the new head office and cost escalations above the rate of general inflation on capital projects, expanded DSM programs, and increased maintenance on existing infrastructure.

9.3 New Generation and Major Transmission

There has been a significant increase in the costs of new generation and Major Transmission projects since 2004. MH cited the increase is due to inflationary pressures on labour, contract services and materials, the latter representing a condition of hyper-inflation, as well as other considerations. A comparison of significant projects cost changes between CEF 04-1 and CEF07-1 follows:

New generation and Major Transmission CEF04-1 to CEF07-1

($ millions)	CEF 04	CEF 05	CEF 06	CEF 07	$Increase 04-07
Wuskwatim G.S.	846	935	1094	1,275	429
Wuskwatim Transmission	199	200	257	320	121
Wuskwatim Total Project	1,045	1,135	1,351	1,595	550
Herblet Lake Transmission	55	54	54	95	40
Bipole III(1)	388	1,879	1,879	2,248	1,860
Pointe du Bois	288	692	834	900	612
Conawapa G.S. & licensing	4,050	4,516	4,978	4,978	928

Note 1: CEF-05 assumed Bipole III would be build east of Lake Winnipeg, the current intention is a western route.

MH indicated a significant escalation in capital costs for its projects that relate to many market factors beyond its control. Utility industry construction costs have risen and are expected to remain elevated for some time, reflecting underlying trends for cost increases for steel, copper and concrete due to high global demand and, as well, increased production and transportation costs due to much higher fuel costs. Another factor is a shortage of skilled workers that has driven costs higher for utility construction services.

9.4 Wuskwatim Generating Station (Wuskwatim)

9.4.1 General

The Wuskwatim Generating Station represents Manitoba's first new hydroelectric development since the late 1980s, and the first in Manitoba structured as a partnership (MH and the First Nations Nisichawayasihk Cree Nation (NCN). In approving the project the CEC recommended that:

> "The Government of Manitoba grant The Public Utilities Board jurisdiction to review, on an ongoing basis, as part of Manitoba Hydro's future General Rate Applications, the actual revenues and costs of the projects relative to forecast, along with the impact of the Projects on Manitoba Hydro's financial stability and its domestic rates."

This application represents the Board's first review of the Wuskwatim project as it now stands.

At the CEC hearing, MH justified Wuskwatim on the basis that the new generating station would be built to serve export markets, and stated that the power from the station would not be required for domestic consumption until 2019. Now, given current firm export contracts and an increase in forecast domestic load, MH indicates the power generated from Wuskwatim will be required by 2012 to meet domestic needs and firm export contracts.

9.4.2 Capital Cost of Project

At the outset, the capital cost of the Wuskwatim project, as presented to the CEC, was estimated at $900 million. The updated cost estimate now indicates a project cost of approximately $1.6 billion, an increase of $700 million since the CEC hearing in 2004, and an increase of $550 million since CEF04-1.

MH attributed the increase to inflationary pressures on labour, contract services and materials. The estimate also increased to account for both the deferral of the in-service date, from 2010 to 2012 and to account for increases in licensing costs.

MH also reported that the Wuskwatim Project Development Agreement allocates MH's overhead costs at a rate of 21% as opposed to the "normal" 29%, this reduction allowing for the exclusion of a share of costs related to Winnipeg facilities and computer systems not expected to be utilized by the project.

9.4.3 Wuskwatim Power Limited Partnership (WPLP)

The project is to be developed by the Wuskwatim Power Limited Partnership (WPLP), an equity partnership between NCN and MH. The project is unique, and represents the first time MH has entered into an equity partnership on a generating station project. MH suggested that the experience gained through the WPLP may be used in structuring agreements for future northern Generation projects, including the now-expected development of Keeyask and Conawapa.

The two Limited Partners are to invest equity in the project by subscribing for ownership units to represent 25% of the total capital cost of the project. The WPLP agreement allows for NCN, through its wholly owned Taskinigahp Power Corporation (TPC), to subscribe for up to a 33% stake in the Equity Partnership Units. MH, through a holding company (General Partner), would have a 0.01% interest, with MH, as a Limited Partner, holding the balance of 65.99%.

The assets of the Partnership are to consist of the Wuskwatim G.S. and required working capital. MH is to lend WPLP the funds required to build the generating station. Based on the Corporation's current estimated cost of constructing

Wuskwatim, excluding the transmission component, MH projects lending the partnership $927 million to build the generating station, representing approximately 75% of the cost of the project (the remaining funding to be through the Equity Partnership Units).

MH assumes TPC will subscribe for 33% of the ownership interest, i.e. 33% of the 25% equity component. Based on the current construction cost estimate for the generating station, TPC's cost for the partnership units would be $102 million. According to the agreements, TPC will invest up to $34 million of its own capital and borrow up to $68 million from MH to fund the balance.

Revenues generated from the project are to be allocated to the partnership from MH's overall revenues, based on an agreed-to (between NCN and Hydro) formula utilizing average export prices for peak and off-peak sales. Revenues are to be adjusted as changes in export prices are experienced and realized, and are to be based on the actual output of Wuskwatim G.S., reduced by the average system line loss rate for the MH system (currently 10%). WPLP is to pay MH 3% of the partnership's gross revenues, to contribute towards the marketing and transmission costs and risks borne by the Corporation.

MH will be fully responsible for the operations of the generating station and related transmission facilities, and will charge WPLP for its incremental operating costs. MH will make no cost allocation to WPLP for system generation and transmission. Control Center costs will not be directly charged to the project but be included in the overhead charge to the project. Finance costs incurred by the Corporation, related to the loans it will take on to allow it make loans to the partnership to build the generating stations, are to be recovered, at cost, from WPLP. The financing cost related to loans to WPLP has been estimated at 7%

interest, based on MH's expected long term-cost of borrowing of 6% plus a 1% Provincial debt guarantee fee.

The proposed Development Agreement requires that WPLP maintain a 75:25 debt to equity ratio, except for the first 10 years of operations where an 85:15 debt to equity ratio will be allowed (to account for anticipated initial losses in the operation of the facilities, losses are expected for the six-year period from fiscal 2011/12 to 2016/17).

If the partnership's debt to equity ratio falls below the above parameters, there is a requirement for further cash contributions from WPLP partners based on their ownership interest in the partnership.

The agreement between Hydro and NCN also allows for advances on dividends to NCN, even during loss years and/or when the equity threshold test has not been met. MH indicated that dividend advances are to be limited to 5% of the actual cash invested by NCN, and are to be repaid by NCN out of forecast future distributions.

9.4.4 Wuskwatim Transmission

In addition to the generating station, Wuskwatim requires incremental transmission facilities. MH is to build the required transmission facilities at an estimated cost of $320 million. The cost of incremental Wuskwatim transmission is to be recovered from WPLP by way of repayment over 50 years, the payments to include principal and interest.

Repayment of the loan is to commence upon Wuskwatim's in-service date, and MH stated that the blended principal and interest payment required will be the equivalent to having the transmission asset and offsetting debt on the books of the partnership and expensing depreciation and interest. In addition, the operating costs of the transmission facilities will be charged to WPLP.

9.4.5 Project Economics

In justifying the Wuskwatim project to the CEC, MH advanced many assumptions. Based on the then-projected construction costs of the project the levelized cost of the energy was to be 6.6¢ per kW.h (costs forecasted before the CEC). Given the escalated cost of the project, the Corporation's revised estimated cost of energy has increased to 7.2¢ per kW.h.

Before the CEC, and in forecasting export prices to be realized by Wuskwatim, MH utilized a USD/CDN exchange rate of 1.35. Based on its most current forecast in 2007, the exchange rate utilized in the Corporation's forecasts as for when Wuskwatim comes in-service in 2012 was 1.14, and this appreciation of the Canadian dollar from the original projection was forecast to result in a 5% reduction in forecast export revenues.

However, if the Canadian dollar remains near par with the U.S. dollar, MH projects export prices will be 17% lower than now forecast, a result that would further negatively impact the economics of Wuskwatim.

At the CEC Hearing, and in the Corporation's justification of the project, MH calculated that the Internal Rate of Return (IRR) would be 10.3%, based on generation being sold as exports. As a result of the escalation in the cost of the project and employing the same type of financial analysis as was presented to the CEC, the IRR has reduced to 7.8 %, excluding sunk costs, and to 6.5% including sunk costs. And, even this revised IRR would be further materially reduced if the Canadian dollar remains at par.

MH cautioned that recalculating the IRR on a similar basis to that presented at the CEC hearing, as reported on above, neither reflects the decision now required nor is consistent with engineering economics. MH's rationale for this view is based on Wuskwatim being built for domestic load purposes, and a comparison of the projected cost of energy to arise from Wuskwatim with the cost expected if that amount of generation arose from with operation of a MH combined cycle natural gas turbine. On that basis, for MH, Wuskwatim is expected to result in $14 million in annual savings over the next 30 years (providing $153 million of net present value).

9.5 Bipole III

Bipole III is to be a 2,000 MW, high voltage direct current (HVDC) transmission line from Gilliam, Manitoba to The Pas, and then down the west side of the Province to Winnipeg, Manitoba. In CEF 07-1 MH budgeted for a West Side Bipole III to be in-service in 2017 with a total cost, including escalation and interest during construction, of $2.247 billion.

The new HVDC line and associated converters (at Henday and Riel) is being advanced for domestic and export transmission capacity and reliability reasons. The recently-announced power sales to Minnesota Power and Wisconsin Public Service, (again not reflected in MH's forecasts as filed at the proceeding) if finalized, will also advance the need for Keeyask and Conawapa generation. On this basis, the new Bipole III line, with its converters, will be required to meet firm export load, as well as strengthen the domestic transmission system.

Due to provincial environmental and societal considerations, MH is proceeding with a West Side of Province routing for Bipole III, rather than the originally planned shorter routing on the East Side of Lake Winnipeg. MH provided a cost-benefit comparison of a West Side Bipole III as opposed to an East Side Bipole III, and identified a $400 million capital cost differential and a line loss differential of up to a further $181 million (in favour of an East Side Bipole III).

MH identified the potential for further significant price increases for construction as a whole, and power generation and transmission in particular. And, if this concern is realized, a further significant increase in forecast Bipole III costs could result.

Evidence presented at the recent hearing suggested that a repeat of the September 1996 failure of Bipole I and II, once Bipole III is in operation, built on the west side of the Province, would have more serious consequences if the interruption occurred during peak load. While an East Side Bipole III could function in parallel with existing Bipoles I and II, and in the event of the outage of both, make use of Bipoles I and II converters as well as the new Bipole III converters to provide 3,000 MW to the south, a West Side Bipole III would be limited to using only its own converters and thus could only provide the South with 2,000 MW in such a situation. MH advised that an outage of Bipoles I and II during the summer season could result in an additional cost to the Corporation of $160 million over the cost that would be incurred if Bipole III were built down the east side, the extra costs due to a requirement for additional imports to make up for the 1,000 MW differential.

In short, during a major outage of both Bipole I and II, an East Side Bipole III could serve both domestic and firm exports, while a West Side Bipole III would require significant additional needs and presumed expensive imports to meet domestic needs and firm exports.

9.6 Other Generation

Pointe du Bois Generating Station

MH is moving forward with its approval process for construction of a new generating station to replace an aged Pointe du Bois G.S. This $900 million replacement project is viewed to be an economically superior option to upgrading the existing plant.

In the 2005/06 Power Resource Plan, MH compared the capital costs of various scenarios as follows:

Capital cost scenarios ($ millions)

Capital Expenditure	Cost Estimate	Timeframe
Decommissioning	$125	By 2014
Rehabilitation	$358	By 2021
Repowering	$562	By 2017
Redevelopment	$615	By 2013

On the basis of subsequent economic, technical, environmental and socio-economic evaluations, MH concluded that the redevelopment of the Pointe du Bois G.S. was the more attractive alternative, with an in-service date of 2015/16. The capital cost estimates based on further analysis were refined and updated to reflect current conditions.

It is not clear whether this new capital requirement was taken into account during negotiations for the acquisition of WH.

Kelsey Generating Station

MH is upgrading the Kelsey G.S., at a forecasted cost of $123 million, by re-runnering the turbines. The intent is to increase plant capacity and gain additional energy output under average flow conditions. MH advises there was no expected gain in dependable flow generation from the enhancement.

Keeyask & Conawapa Generating Stations

In January 2008 after the GRA had been filed with the Board, MH announced it had signed a term sheet for a 250 MW power sale to Minnesota Power. And, at the hearing, MH stated that it had just signed a term sheet (an intent to sell) with Wisconsin Public Service (WPS) for 500 MW, the sale to start in the year 2018 for a 15-year term, with an expected value of approximately $2 billion over the term.

Occurring after MH had filed its GRA, the WPS sale was not considered in MH's filed Power Resource Plan. The sales, Minnesota and Wisconsin, are contingent on MH developing new hydro generation. New transmission inter-tie capabilities will be required by both MH and the counter-parties to the agreements, again to meet a condition of sale.

MH will require new transmission from Riel Station, on the East Side of Winnipeg, to the U.S. border, and estimated the cost of the Manitoba portion of the new transmission inter-tie to be approximately $30 million. Costs related to the new transmission line were not included in CEF07-1, and MH also suggested that additional Alternating Current (AC) transmission could also be required to optimize the new generation projects.

MH indicated it could have to develop Keeyask (620 MW) and Conawapa (1,420 MW) generating stations in close succession, (2018 and 2021, respectively) to meet the new export sales requirements. MH forecast that the cost of Keeyask, at approximately $4 billion, also not included in CEF07-1, and Conawapa, estimated to cost approximately $5 billion, of which $2.8 billion in capital cost are forecasted to be incurred after the current CEF07-1 forecast period of 2018, were not fully included in the latest IFF or CEF. (Recently, public statements have suggested that the cost of the Conawapa capital project could reach $6 billion.)

MH further stated that it may be required to build a combined cycle natural gas fired plant, at a cost of approximately $600 million, to meet projected energy deficits that could arise as early as 2017, ahead of Keeyask and Conawapa coming on stream. The cost of a new combined cycle natural gas fired plant was not incorporated in the current capital forecast, or in the latest IFF.

In short, the impacts expected to arise from the two new power sales are not fully incorporated in MH's forecasts; and IFF07-1 and CEF07-1 are to be revised by MH, with a copy to be filed with the Board.

9.7 New Head Office

As a condition of the purchase agreement entered into when WH was acquired, MH agreed to build a new Corporate head office in downtown Winnipeg. The building was originally forecast in CEF 03-1 at a cost estimate of $75 million, the amount then cited as a 'place marker' subject to design changes and cost revisions.

The new building is to accommodate approximately 2,100 employees and to be ready for occupation by 2009, and come at a projected revised cost of $278 million. Issues related to MH's new head office were also reviewed by the Board in Order 99/07, wherein the Board noted:

> "Centra estimated that overall cost impacts of the new head office would be \$21 million per annum, to be offset by lease payment savings of \$5 million and annual productivity savings projected to be in the range of \$20 million annually. Centra assured ratepayers there would be no increase in rates".

The Board directed in Order 99/07, that:

> "Centra confirm to the Board that no incremental costs are to accrue to Centra's customers for MH's new head office;"

MH, on behalf of Centra, provided that confirmation in this GRA.

The incremental annual cost related to the new building was estimated at \$22.8 million in the first year of occupancy, with an annual cost of \$18.75 million thereafter. MH expects that productivity savings will be realized by bringing staff together at one location, allowing staff to work in closer proximity and in a more efficient environment, and that this will be sufficient to result in synergy savings of between 10% and 20% of otherwise head office payroll, to offset in part the incremental costs of the new building.

MH further stated that \$20 million in productivity savings, to also include lapsed leases for currently-rented facilities, will be realized and offset the increased costs from the new building.

That said, MH indicated it would be difficult to focus on the details of savings associated with the new head office at future hearings. MH recommended the Board focus on the review of costs and savings from an overall basis to ensure that costs are fair and reasonable, rather than focusing on the head office.

While the new head office is being constructed as an obligation made upon the acquisition of WH, moving to common facilities may benefit both MH and Centra in terms of more efficient operations and better customer service, to be achieved through enhanced collaboration opportunities. Given that the costs allocated to MH's electricity and Centra Gas natural gas operations are based upon the costs incurred, any productivity savings that are attributable to providing service to gas customers would flow to Centra through the normal cost allocation process.

MH opined that substantial benefits were flowing to Centra as a result of the acquisition of WH and the related move to common facilities, and recommended that continuing to allocate the actual costs of the work performed on behalf of each utility to each utility would be the best course of action. As such, for MH there should be no special allocation process implemented to ensure that the costs of the new head office flow only to electric customers.

9.8 Interveners' Positions

The Coalition

The Coalition commented that the interaction of MH and the Province has led to tremendous benefits for Manitobans, citing benefits that included rural interconnection, connection of remote communities in the north, the northwest transmission developments, and cooperation between MH and the province that has realized significant economic development and provided contributions to provincial finances. The Coalition also stated it was important to also recognize costs to the Province in terms of these developments, including mitigation expenditures related to the Churchill River diversion.

The Coalition also observed ongoing impacts on MH's revenue requirements and financial indicators that are a product of the interaction between MH and the Province. The Coalition mentioned the new head office and the west side vs. east side debate concerning Bipole III as issues with important cost consequences.

In terms of Wuskwatim, the Coalition noted that the development is placing pressure on MH's debt to equity ratio and on its revenue requirement. In addition, the Coalition noted that the intended closure of the Brandon Coal plant (that is except, for emergency use) is another important impact arising from provincial involvement in MH decision-making. The Coalition stated that MH is experiencing significant pressures on its financial results from a variety of government policy and other initiatives, though many of them have, in the past, been beneficial to Manitobans.

Mr. Harper noted that MH's capital spending for the two closest forecast years, 2007/08 and 2008/09, is to be considerably higher than historic levels, mainly due to higher spending on new generation and transmission. Mr. Harper stated the spending is in part to protect in-service dates and is being done to meet export commitments and goals, and that this spending is putting noticeable pressure on MH's debt to equity ratio.

As of fiscal 2006/07, Mr. Harper opined the impact of spending on major new generation and transmission projects has increased the debt ratio by 2 percentage points. And, by fiscal 2008/09, increased capital spending will drive up the debt ratio by 5 percentage points.

Mr. Harper submitted that in the near term, Wuskwatim will have the most impact on the change in outlook for capital spending, due both to cost increases and as a result of the advancement of the in-service date. The Coalition observed that MH's capital spending plans influence decisions about the level of net income and the level of rate increases.

As previously mentioned, Mr. Harper argued for a direction to Hydro to develop an ACA and described an ACA as a snapshot of the condition of a utility's assets, noting that it would include degree of degradation and need for rehabilitation and replacement. He suggested that ACA are usually undertaken at intervals of two to three years.

Mr. Harper claimed that an ACA helps a utility pull together, on a systematic and organized basis, an overall comprehensive assessment (for planning purposes) of work to be prioritized across its entire asset base. And, through a process of prioritizing assets by way of an ACA, MH can further prioritize work in areas of the company where there is a deficiency of a critical nature. Mr Harper stated an ACA provides a logical foundation to support OM&A and capital spending

Mr. Harper further recommended that MH undertake regular ACAs every 2 to 3 years, and that the preparation of such assessments over time will allow MH to determine whether its assets are improving or deteriorating, helping to substantiate where there is a need for increased spending.

Mr. Harper noted that MH's capital spending requirements for both base capital and new generation and transmission projects are growing, when compared with past spending levels. He indicated that while increased export revenues should benefit future customers, the capital expenditures to prepare for those exports are putting pressure on current rates and are one of the drivers for MH's requested rate increases (that now exceed inflation). For Mr. Harper, MH needs to be mindful of these pressures when developing its overall capital expenditure plans.

Mr. Harper opined that the advancement of Wuskwatim was a contributing factor to current rate pressures. In reaching this conclusion, Mr. Harper noted that a significant portion of the increases in capital spending to be experienced in the next few years relate to the development of Wuskwatim.

The Coalition stated that there were lessons to be learned from the Wuskwatim development, lessons best learned before entering the anticipated decade or more of major capital expansion. The Coalition cited submissions made by MH to the Wuskwatim CEC proceeding, that:

> "Temporary increases in MH's debt to equity ratio and decreases to the level of interest coverage which may occur in the early years of the project are judged to be manageable without impacting the Corporation's financial stability or requiring off-setting increases to domestic rates."

The Coalition further cited the CEC report which stated:

> "The Commission's support for the project is contingent on Manitoba Hydro being able to maintain its commitment that domestic ratepayers will not experience rate increases as a result of the project."

The Coalition noted that the project is now forecast to cost $ 1.6 billion, including transmission. Taking into account both inflation and the effects of the delay in-service date, the Coalition noted an increase of $418 million (in 2002 dollars) in the expected cost of construction, and that as a result, the IRR, based on the methodology employed in the submission to the CEC, has been reduced to 7.8% when sunk costs are excluded, and to 6.5% when sunk costs are included.

The Coalition submitted that the revised IRR of 6.5% is roughly equivalent to the Corporation's cost of debt, and suggested that the lesson to be learned from the deterioration of expected return is that the CEC hearing did not examine closely enough the capital expenditure forecasts of MH.

As to the new head office, the Coalition questioned whether synergies forecast by MH will be realized to offset the approximate $20 million increase in annual costs.

As MH enters into a decade of expansion, the Coalition recommended that MH employ an independent review of both its capital expenditure procedures for major projects and also for its OM&A expenditures, considering both in terms of forecasting and management best practices.

The Coalition also recommended that the Province provide the Board the legal jurisdiction to review MH's major capital expenditures.

MIPUG

MIPUG also expressed concern with the growth in MH's capital spending. Mr. Bowman and Mr. McLaren suggested that the increase in capital spending has contributed to a deterioration in MH's financial position and is one reason that MH's debt: equity targets have not been achieved. Mr. Bowman and Mr. McLaren mostly attributed the failure to meet the accepted targets to major new generation and transmission plans, including Wuskwatim.

Given that these new projects were to be pursued on MIPUG's understanding that they would not drive rates higher for domestic customers but would, over the long term, benefit domestic customers, the witnesses opined that the use of these capital projects as an implicit justification for rate increases should be of concern to the Board.

MIPUG stated that although MH had not indicated it was seeking rate increases to address the costs of bringing Wuskwatim into service, the net effect of retaining the 75:25 debt to equity ratio target requires rate increases from domestic ratepayers.

In assessing the level of MH's capital spending and its impact on the province, MIPUG suggested the Board should set rates that both reflect the cost of operating the Utility plus provide provisions or reserves for the maintenance, operation and eventual replacement of existing assets.

For MIPUG, there is no basis or regulatory convention allowing the Board to focus on the credit condition of the shareholder (the Province) in determining rate levels. For MIPUG, the Board's role is to focus on the financial condition of the Utility, solely for the benefit of its customers.

MIPUG also opined there was no basis to argue that rates should be increased for "balance sheet" reasons, i.e. to "pre-fund" the equity required for the coming phase of capital expansion (Conawapa, Bipole III, Keeyask, new cross-border transmission, Wuskwatim and Pointe du Bois).

MIPUG strongly opposed the Board taking into account concern for the Province's credit rating, and suggested that to do so would be roughly equivalent to raising rates in the 1950s to advance Grand Rapids, which came into service in the 1960s. MIPUG contended that such an approach would not have been necessary, as the Grand Rapids project, as a long-lived MH asset, has been able to cover its interest costs, repay all debt borrowed for the purposes of its construction, and provide cost-effective power for generations of ratepayers..

MIPUG cited prior Board Orders which expressed concern as to the implications of increased capital spending by the Corporation, noting from Order 143/04:

> "The Board continues to be concerned with the progress of substantial growth in capital expenditures and accompanying debt. The Board accepts that many of the capital expenditures are related to reliability and safety, and therefore are may [sic] be prudent to incur. The Board also recognizes that many of the forecast capital expenditures are related to or the equivalent of generation expansion, such as supply side enhancements, Wuskwatim, Keeyask, Conawapa, and may be justified individually when considering the each project purpose and forecast results over the long term. However, collectively these projects negatively impact MH's debt to equity ratio of and

> net income in the initial years, placing increase strain on the financial stability of the MH and adding additional risk for existing ratepayers. The Board is concerned that MH has not developed a threshold for capital expenditures and associated debt growth that considers all projects, together with the health and financial stability of the company."

MIPUG noted that MH's normal capital program has not been reduced, despite the Board's "strong" directives of Orders 7/03 and 143/04. MIPUG argued for greater regulatory scrutiny of capital spending, and urged the Board to continue to seek the necessary legislative amendments, as sought in past Orders to provide for Board oversight of MH's capital expenditures, an oversight that, for MIPUG, would be consistent with the objectives of *the Public Utilities Board Act*.

Mr. Bowman and Mr. McLaren cited CEF 07-1 as indicating that MH will be spending approximately $4.1 billion on <u>normal</u> capital programs to 2017/18, an average of $375 million per year. When compared to CEFO2-1, where normal capital spending was forecast to be $3.1 billion, an average of $285 million per year, the witnesses expressed concern over an increase of 30%, or 6% per year.

Mr. Bowman and Mr. McLaren noted that this level of growth, only half being consistent with expected general inflation over the period, was excessive. They opined that with capital project cost escalation occurring, it is possible that while a 6% sustained annual growth may be justifiable as reflective of premium "construction project" inflation over the period, MH has not reflected any notable cost control measures consistent with the Board's past directives.

MIPUG again recommended the Board should pursue oversight of MH's major capital projects, perhaps via a recommendation to the government for a legislative provision similar to the Certificate of Public Convenience and Necessity process that occurs in other jurisdictions.

MIPUG further stated that in the event additional Board oversight is not provided by government, nonetheless the Board clearly retained the ability to set the Utility's rates, and could employ that ability to ensure MH is not provided upward rate adjustments to compensate the Corporation for investments the Board may not view as prudent. MIPUG stated that the Board is not bound to "adequately fund" all operating and capital decisions made by the Utility, and that the Board should reach a conclusion on the prudence of the expenditures to be reflected in rates.

MIPUG further suggested that the Board request renewal of the mandate provided the Board in 1990 (via OIC 1990-177), a mandate that provided for a detailed and comprehensive integrated review of MH's Major Capital Projects (covering the period 1990 to 2009). Among the other benefits MIPUG suggested would arise from such a review, MIPUG suggested that the Board's resulting report to the Lieutenant Governor-in-Council, which would arise from the review, could include a discussion of compelling policy considerations for the Government of Manitoba to address. Given the current expansion plans of MH, MIPUG held such a review would be timely.

MKO

MKO noted that MH has an aggressive capital plan that may be the most extensive in the Corporation's history, with the possible exception of the previous nearly back-to-back projects at Grand Rapids and Kettle.

MKO agreed with the position put forward by MIPUG, and suggested the Board should take on the responsibility to review major capital expenditures expected to have an impact on rates.

MKO further recommended that the Board acknowledge that MH-affected First Nations are, in essence, the original capital investors in the MH system. MKO asserted that Article 18.4 of the 1977 Northern Flood Agreement acknowledges its assertion.

Accordingly, MKO recommended the Board acknowledge that MH-affected First Nations are, at minimum, co-investors in MH's hydroelectric generating facilities, and are, in effect, "perpetual holders of Class "A" shares (in MH)", for which a return on investment should be identified and "paid" to First Nations.

RCM/TREE

RCM/TREE also noted that MH is facing significant capital costs with the major construction projects now expected and suggested that the capital costs to be incurred will take place at a time when MH has a high debt:equity ratio.

RCM/TREE suggested that even with the new construction programs, MH is forecasting energy shortages in the years 2009 to 2011, shortages to arise from accelerated domestic load growth. RCM/TREE indicated that load growth continues to exceed past projections with negative impacts on MH's finances, customers and the environment

RCM/TREE suggested that the consequence of 'suppressed electricity rates' is increases in domestic load growth that go beyond previous predictions, and that the increasing load growth threatens the export surplus, hastens the requirement to construct more costly new plants for domestic use, escalates the level of greenhouse gas emissions in North America, and has the potential for an adverse impact on Centra Gas' results and situation "if the flight from gas to electricity for water and space heating continues".

9.9 Board Findings

The Board recognizes its statutory jurisdiction does not extend to the approval of capital expenditures. Yet, it is clear MH's anticipated capital spending and associated increased debt levels is and will place upward pressure on rates. The Board has, as interveners have noted, expressed concern with MH's debt growth in previous orders. In Order 143/04, the Board noted:

> "The Board continues to be concerned with the progressive substantial growth in capital expenditures and accompanying debt. The Board accepts that many of the capital expenditures are related to reliability and safety, and therefore are may [sic] be prudent to incur. The Board also recognizes that many of the forecast capital expenditures are related to or the equivalent of generation expansion, such as supply side enhancements, Wuskwatim, Gull, Conawapa, and may be justified individually when considering each project's purposes and forecast results over the long term.
>
> However, collectively these projects negatively impact MH's debt to equity ratio and net income in the initial years, placing increased strain on the financial stability of MH and adding additional risk for existing ratepayers. The Board is concerned that MH has not developed a threshold for capital expenditures and associated debt growth that considers all projects, together with the health and financial stability of the Company."

The Board reiterates the prior concerns, and notes that with planned major capital expansion, such concerns are now graver.

In this GRA, interveners requested that the Board revisit its prior recommendations and recommend to government that the Board be provided with the statutory authority typically vested in the public utility regulators – that is, the authority to review MH's capital expenditures before such investments are committed.

In prior Orders, the Board has recommended to Government, that *The Public Utilities Board Act* be amended to make the regulation of MH equivalent to the regulation of Centra Gas by removing the exemption now provided under Section 2(5) of the Act.

In Order 143/04 the Board noted:

> ”Given the risks related to the very significant additional plant investments and associated borrowings contemplated, the Board is of the view that the Province of Manitoba should re-evaluate the existing legislation.”

The Board reiterates its past recommendation.

The Board’s concern with MH’s capital spending has previously been described, (Orders 07/03 and 143/04). With this new GRA, and with the update provided during the hearing, MH has set out planned capital expenditures that are unprecedented in the Utility’s history. The Capital Expenditure Forecast projects that from 2008/09 to 2017/18, the Corporation plans to spend $11.3 billion (of which $7.5 billion is for new major generation and transmission assets and $3.8 billion for other power supply requirements) – with further capital expenditures likely to also occur given recent export sales (i.e. Keeyask and Conawapa).

In its application, MH projected that its in-service undepreciated plant will increase by $8.6 billion to reach over $20 billion by the end of 2018, and that its debt would correspondingly increase from $7.2 billion to almost $12.7 billion by the same end date. In addition, due to recently-reported potential new long-term export contracts to Wisconsin and Minnesota, capital expenditures are expected to further increase. Assuming they are finalized, the new export contracts will require additional generation and transmission expenditures of a currently estimated cost of another $7 billion (for the planned construction of Keeyask by 2018, and Conawapa by 2022).

The additional capital expenditures are not reflected in the current capital forecast, and accordingly, the Board will, require MH to update and extend its forecasts to include the new projects. The overall level of capital spending now anticipated will result in a large increase in debt that will result in higher finance (interest), depreciation and OM&A expenses. The Corporation's debt:equity ratio, already not at the target range, will also be negatively affected.

And, based on historical experience, and consistent with MH's forecast with respect to Wuskwatim, new generating stations can be expected to operate at a loss during a large part of their first decade of operation, and this too will add pressure on the financial targets, debt levels and rates.

Limestone G.S., which came on line in 1992 at a favourable capital cost, did not achieve any positive cash flows from export sales during the first eight years of operations. However, the project recovered the initial shortfalls and now continues to contribute substantially to the Corporation's bottom line. In the absence of Limestone G.S., MH could not anticipate any significant export revenues in the IFF 07-1 forecast period.

With unexpectedly high capital costs and a somewhat flat export market, Wuskwatim G.S. may not achieve a positive cash flow for a period exceeding the projected loss estimates of the Corporation. By the time Wuskwatim can be expected to "break into the black" its output will serve domestic load only and the advancement of the project for export purposes, as originally planned, will not have proven out.

It could be reasonably expected that the advancement of Bipole III, Keeyask and Conawapa projects will face at least a decade of negative cash flow, even if transmission inter-tie capabilities are doubled. Thereafter these projects are projected to contribute to the bottom line as long as there is substantive action in the MISO region toward achieving CO_2 emission reductions.

To allow the Board to gain a further understanding of the implications of the capital expenditures now contemplated, MH is to file with the Board by January 15, 2009 an updated Capital Expenditure Forecast, and an Integrated Financial Forecast and Power Resource Plan and Load Forecast, all to extend from 2008 to 2028.

The updated Power Resource Plan should provide alternative scenarios with and without implementation of the pending new export contracts and related capital spending. It should also provide an indication of what hydro generation opportunities remain, such to be feasible opportunities, after Wuskwatim, Keeyask and Conawapa, and where the additional projects would occur and what possible quantity of energy would be expected, along with the assumed development timeline. The Load Forecast should also reconcile projected and actual DSM savings.

While MH anticipates that interest rates and inflation will continue to be low, history suggests that both factors fluctuate. Increases in either interest rates or inflation would be problematic to the costs of the proposed capital expansion program. Construction cost inflation over the past five years has been dramatic, in some years 10 times or more the rate of general inflation for some construction cost elements, particularly commodities. As to currency fluctuations, this factor is also subject to widely different possible scenarios, again outside the control of the Corporation (excepting, and to a limited degree, for longer-term “natural” hedges, and, for the short-term, financial instrument hedges).

While the Board agrees interest rates, currency fluctuations and commodity costs are affected by events outside MH’s control, the Corporation should still consider the risks of undue developments in these factors as it plans.

In the Board's view, the capital expenditure forecasts for future construction may prove to be low, thus it would be prudent to model worst case scenarios as well as those considered more likely and reasonable by the Corporation.

MH's export commitments appear to be the recent driver of the need for new major generating stations and transmission facilities. With the exception of Wuskwatim, which was reviewed by an expanded CEC hearing on the basis of export (not domestic) need, the new major capital project and export commitments have not been subject to regulatory review.

Such major capital projects and export agreements can either help or negatively affect MH's financial position, and one of the possible negative outcomes is the potential for rate increases. This was the case in 2004, when MH experienced a drought and the honouring of its export commitments came at a great cost and had a role to play in the rate decisions then made.

The consumers of MH electricity, as represented at the GRA by MIPUG, Coalition, MKO and RCM/TREE, advocate that the Board pursue oversight of MH major capital projects. MIPUG suggested a further recommendation to the Government of Manitoba, to establish legislation similar to the 'Certificate of Public Convenience and Necessity' employed by other regulators. Alternatively, Interveners want a review of MH's major capital projects through a renewal of the mandate provided to the Board in 1990 (via Order-In-Council 1990-177), when the Board was requested and did review MH's major capital plan, then covering 1990 to 2009 (a plan much modified since).

And, given the emphasis placed on exports (the source of rate subsidies for domestic customers and capital for early construction), and the risks for domestic customers if export commitments and water conditions collide, it could lead to significant financial losses.

The Board agrees with Interveners that regulatory review of the impact on consumer rates that MH's planned capital program may have is warranted, and that such a review should consider the risks faced by the Corporation and its ratepayers.

In light of the unprecedented capital expansion now under consideration, the Board will direct MH to propose to the Board on or before January 15, 2009 the terms of reference for a regulatory review of MH's planned Capital Program and its possible implications for consumer rates. The Board will also direct MH to prepare a study, for filing with the Board by January 15, 2009, a thorough and quantified Risk Analysis, including probabilities of all identified operational and business risks. This report should consider the implications of planned capital spending, taking into account revenue growth, variable interest rates, inflation experience and risk, and potential further currency fluctuation.

To provide the maximum benefit of such a risk analysis, MH will be directed to file by September 30, 2008, for Board approval, a conceptual outline for an in-depth and independent study of all the operational and business risks facing the corporation. And, as a follow-up to the risk analysis study, MH will be directed to file, by June 30, 2009, recommended risk mitigation measures and a review of possible suitable capital structures, given the capital expansion now planned or contemplated, and risks quantified.

As for Wuskwatim, it is now clear that the economic justification presented to the CEC in 2004 has changed. At the CEC hearing, MH calculated the projects IRR (Internal Rate of Return) would be 10.3%. Before this Board and incorporating changed assumptions in that original forecast, a recalculation of the IRR yielded 6.5%, a yield that approximates MH's current annual cost of debt.

With higher than expected domestic load growth, Wuskwatim is now required to meet both domestic load and firm export commitments. However, the project is now of debateable economic value, given the ongoing escalation of construction costs and the potential for under-achievement of forecast export prices.

Wuskwatim's original cost estimates, as provided to the CEC, have risen by a factor approaching 2 – with the overall cost now expected to be not $900 million but $1.6 billion. The cost increase is troubling enough, but there is also no assurance that export sale prices have increased correspondingly (if at all). The dramatic rise of the Canadian dollar has lowered revenue expectations, and there is no certainty that either a cap or trade on carbon tax is on the immediate horizon, to benefit MH's planned newest generating station.

MH does not forecast that WPLP will be profitable for the first 6 years of operations, and these forecasts may be optimistic. While MH's cost allocation approach favours the Wuskwatim project, with the Wuskwatim partnership not being allocated all costs, particularly indirect overheads, yet being assigned full export prices for all of its energy output, it is possible the project in a full economic sense may not achieve a positive cash flow.

On an overall economic basis, with construction cost estimates up 60% more and the forecast price per kW.h basically unchanged, Wuskwatim's net present value may not meet the original floor threshold assumed at the CEC hearing. MH now bases its requirement for Wuskwatim on domestic rather than export requirements. Accordingly, MH states it no longer requires Wuskwatim to meet or exceed its threshold economic return, as MH now classifies the construction as being necessary to meet future Manitoba load requirements.

That said, the Board does not agree that Wuskwatim is required for domestic purposes, particularly with its current expected in-service date. Yet, this view is of little consequence, as the Board is not required to give approval to MH's capital plans and projects. As well, Wuskwatim's plans are well past the "point of no return". Yet, it is neither the fault of MH or the government that high inflation and a much higher Canadian dollar has developed massive construction cost over-runs and problems with export receipts in Canadian dollars.

As to the arrangement with NCN, the First Nation is to receive up to 33% of ownership of the limited partnership that will construct the generating station. Yet, and until the project is finished, NCN is required to invest only $1 million, with MH borrowing what is required to complete the project. Following completion, NCN will have to make its decision whether to come in as a partner or not. Overall, and assuming NCN does take up the full ownership position it has the option to take, NCN is only required to put up $34 million of its own capital, the balance to be borrowed from MH.

The First Nation carries no direct risk with respect to the $1.6 billion project. It has an option to take up to a 33% ownership position, but it need not do so; it can evaluate the situation upon the project's completion. And, an NCN holding company will hold NCN's partnership interest in the project. With the holding company inserted between it and the partnership, and with almost all of its investment funded through a loan from MH, without any mark-up, its risks are negligible. As well, NCN will be able to receive payments from the partnership once the new generating station is in-service, even during partnership loss years. Such advance dividends will also be funded by loans from MH, as advances on future dividends.

With respect to the capital structure of the partnership, the standard formula for determining MH's debt to equity ratio has been amended, and for the Wuskwatim partnership the debt to equity ratio will exclude the expected $320 million in debt related to the necessary transmission line loan. This arrangement, having the transmission asset held “off-balance sheet”, and by MH directly, will allow for profit-sharing to occur much earlier than would be the case if the standard 75:25 ratio test was applied employing the standard debt and equity components.

MH concurred with the hypothesis that the Wuskwatim/NCN arrangement was driven by factors other than "strict economics", and that the driving factor for the arrangement is MH's operative assumption that without an agreement with NCN Wuskwatim could not proceed. The Board notes that as the generating station and related transmission lines will be located in NCN's traditional trading area, it is not surprising that the First Nation would insist on compensation for its support of the project, and that a lack of support from NCN would have made proceeding unlikely.

From the Board’s review of the WPLP Agreements, it has arrived at significant concerns with the financing arrangements, cost sharing and revenue allocation, and while there may be reasons that go beyond strict “economics” that lie behind the terms of the arrangement, the Board’s concern with the overall structure of the arrangement is such that the Board cannot, at least without being in receipt of further rationale, recommend that the agreements serve as a template for any future joint ownership opportunity.

While the WPLP is not recommended for use as an “automatic” template for further First Nations participation in Generation and Transmission projects, the experience of Wuskwatim, todate, should be used to model possible outcomes of possible future arrangements with respect to Keeyask and Conawapa.

For any future projects where joint ownership is contemplated because of the potential impact on consumer rates, the Board recommends MH seek the Board’s prior review and approval.

With respect to Bipole III, MH reported that its construction cost estimates had increased dramatically, from IFF-03's forecast of under $400 million (that estimate excluded the cost of converter stations) to $2.2 billion (which now includes the advancement by several years of the construction of converter stations, required for future generating facilities now contemplated).

The increase in forecasted spending is primarily driven by a government policy decision, supported by MH's Board of Directors, to place the line on the west side of the Province and materially increased construction costs.

The Board notes that the new $2.2 billion forecast neither includes the present value of line losses associated with the longer distances required to go down the west side of the Province, nor any value that could be associated with the additional risks pertaining to the possible future loss of Bipole I and II transmission, which, if it occurred, would require northern transmission from the north to the south to come only from Bipole III, at a potential capacity loss of 1,000 MW.

Including the present value of the additional line losses associated with increased distance, the revised routing of Bipole III has added over a half a billion dollars of additional costs. The Board notes that export prices are set in the marketplace and are not based on MH's generation and transmission cost. Thus, it is not the Board's assumption or expectation that the additional costs for a 'west side' routing of Bipole III can be passed on to MH's export customers. It appears that the increased cost of Bipole III, brought about by a west side route will be a cost to MH that will reduce otherwise expected future export profits.

Again, it is critical to understand that this Board is not empowered to approve MH's capital expenditures. To similar effect, the Board is required to honour explicit government policy. Given these conditions, the Board's options are limited when it comes to the rate regulation of MH.

To "starve" MH by suppressing rates in an effort to stymie a project would be to counter government policy, a measure that the Board cannot undertake, first lacking the legislative authority and secondly, the public mandate – unlike government, this Board is not elected. In short, government and the Board of MH has, as they should, taken responsibility for the major capital expenditures and policy actions of MH. The Board has no mandate to contradict such policies. Therefore, while the Board does not find all of MH's actions justifiable on a strictly MH-centric economic rationale, it considers itself obliged to ensure MH has sufficient revenue to allow it to achieve objectives transparently established or approved by government.

Before moving to a general discussion of MH's other capital expenditure plans, the Board has some further comments to make with respect to the projected routing of Bipole III.

Currently, Manitoba Hydro's primary electricity production, from the north, is transmitted through two transmission lines from Gillam to Winnipeg through the Interlake. For a considerable period of time, it has been assumed that a third line was required, for reliability purposes, and with the continuing growth of domestic load and committed or intended export contracts, the third line has become a necessity. Upon its completion, now scheduled for 2017, Bipole III will provide backup to the existing two lines and transmit increased volumes of electricity from the planned new generating stations to southern Manitoba and further south, the primary export market.

Bipole III, to be MH's third high-voltage, direct-current transmission line, is to be constructed down the west side of Lake Manitoba, rather than taking a much shorter route through boreal forest on the east side of Lake Winnipeg. The east side of Lake Winnipeg is marked by pristine boreal forest, which the government has indicated it wants to preserve by building Bipole III down the province's west side, rather than the east.

The government, in partnership with some “east-side” First Nations, seeks what is considered to be the second-largest intact boreal forest in the world to be designated by the United Nations Educational, Scientific and Cultural Organization (UNESCO – through UNESCO’s Word Heritage Committee) as a World Heritage Site.

World Heritage sites are important, having significant positive impacts for decades to come, draw considerable world attention, and can attract significant eco-tourism. The government has indicated that an attempt to construct a major transmission line through a potential World Heritage Site would be strongly resisted by First Nations and be so opposed by environmentalists that it could result in MH’s export potential being severely damaged. In short, the Board understands that the government’s claim is not based on “economics”, particularly “relatively” short-term economics, but broader concerns extending beyond the environmental to include the cultural and the political.

There is little doubt that the proposed route down the western side of the province is both longer and will cost hundreds of millions more than if the new transmission line were to be built on the east side of Lake Winnipeg. As the precise route for the line cannot be determined until a process of environmental, design and public consultation has taken place, the certainty of the government’s final direction cannot be assured.

While opponents and/or critics of a “west-side” Bipole III include interveners at this most recent GRA proceeding, with their criticism based largely on "economics" (the undisputed understanding is that a west-side line will cost more than an east-side approach, result in increased line losses due to the longer distances involved, and, as discovered through this recent proceeding, pose an increased reliability risk in the low-probability occasion of Bipoles I and II being out of service), neither the interveners nor MH set out in detail the argument for the west-side siting of Bipole III directed by government.

The Board's mandate is to determine what is in the public interest, and has previously defined this Board's definition of what represents the public interest with respect to a public monopoly utility incorporated and operated to provide required services to Manitoba. So, while this Board does not have the statutory authority to approve or reject MH's capital expenditure plans, it certainly does have a considerable interest in what those plans are and as to what the basis for those plans are. Capital expenditures represent a major driver of rates, and this Board does have oversight and responsibility for rates.

Accordingly, the Board, in this Order, sets out herein its conclusions to date on the rationale and implications associated with building Bipole III. In setting out its perspective on the matter as it now stands, the Board concludes that it is also in the public interest to set out, as it has above, the Board's understanding of the government's, and MH's, rationale for the decision to take Bipole III down the west-side.

The gist of MH and the government's position on the matter is that taking Bipole III down the west side of the Province will better ensure the Utility's reputation and relationship with its major American export customers, and provide an opportunity to achieve, develop and enjoy a potential World Heritage Site.

In short, it is the Board's understanding that MH and the government have concluded that constructing Bipole III on the West side of Lake Manitoba is, on balance, and despite it being considerably more costly and carrying additional risks, the only truly available option at this time (assuming domestic load growth and export commitments are to be met and reliability better assured).

Finally, the Board notes a third potential option, one involving underwater cables that would carry the power through at least a portion of the distance required. The Board senses that discussion and review is likely to continue, and, until that is concluded, is content with setting out its understanding of the costs and implications of the concepts and plans provided to-date.

10.0 Load Forecasts and Power Resources

10.1 Load Forecast

MH’s 2005/06 metered domestic load was 20,800 GW.h., comprised by:

Residential	6,578 GW.h	32%
GSS-ND	1,329 GW.h	6%
GOSS-D	2,038 GW.h	10%
GSM	2,949 GW.h	14%
GSL<30	1,612 GW.h	8%
GSL 30/100	988 GW.h	5%
GSL >100	5,202 GW.h	25%
ARL	96 GW.h	<1%

The segmented metered load corresponds to a load at generation of 22,899 GW.h, after taking into account distribution and transmission losses as well as weather adjustments.

MH forecasts base domestic loads at generation of:

23,318 GW.h in 2006-07	actual	
23,769 GW.h in 2007-08	451 GW.h increase	2%
24,577 GW.h in 2008-09	808 GW.h increase	3%
25,509 GW.h in 2009-10	932 GW.h increase	4%
26,069 GW.h in 2010-11	560 GW.h increase	2%
26,503 GW.h in 2011-12	434 GW.h increase	1.5%

The forecast indicates a 3,200 GW.h increase (14%) in domestic load over the five-year period, which compares to a forecast 2,350 GW.h increase forecast for the same period in the 2005/06 load forecast. (Peak load grew by 10% during that period of 750 GW.h increased usage.)

MH's 2006 Electric Load Forecast indicated that residential and commercial load growth of 1% is expected from 2006/07, and onward that industrial load growth (GSL customers) of about 2.3% annual growth should be expected from 2006/07 to 2011/12, and a further 1% per annum or less thereafter.

The chemical and petroleum transport sectors of MH's industrial customer class are expected to provide about 75% (1,300 GW.h/year) of the 1,700 GW.h total anticipated industrial load growth between 2006/07 and 2011/12. These industry sectors are energy intensive and are usually associated with relatively low levels of employment per GW.h of energy consumption. Projected load growth in the sector has not been expected to produce high levels of additional Manitoba employment. As such, the sector represents the primary target for MH's interest in a new industrial rate class that would be assessed marginal rates.

The projection of load growth does not provide for the potential arrival of new industries in Manitoba with similarly low levels of employment per GW.h. Such firms, which may be attracted by low energy rates, would reduce MH's export sales and affect general consumer rates, and, as well, possibly affect the now planned in-service dates for new generation and transmission.

This situation has led to a concern that MH may have to increasingly forego export sales (at prices from 5¢ to 7¢/kW.h) in order to service domestic industrial loads assessed at 3.5¢/kW.h or less.

Again, to counter the impact of reduced exports caused by low-employment energy intensive industry, MH sought approval for a new energy intensive rate, one more reflective of export market pricing. However, the rate proposal has been deferred to a subsequent hearing, now expected to occur later this year or early in 2009.

MH's domestic load forecast contemplates:

- Only nominal increased demand from electric space heating;
- Significant increase in demand from electric water heaters;
- Significant increase in demand from computer and internet usage;
- No increased demand relative to climate change (global warming);
- Little change in seasonal load variation due to climate change;
- A significant increase in electric load due to customer movement from natural gas to geothermal heating but no identified decease for customer movement from electric to geothermal heating;
- No customer movement from natural gas to electric heating; and
- No change in loads due to self-generation.

Given the lengthy planning process required for new generation and transmission, the accuracy of domestic load forecasts, including the categories of customers associated with specific forecasts, are critical to assessing MH's domestic load and opportunities for exports. A major risk to the present load forecast lies with the nexus of natural gas and electricity, with natural gas potentially to be a more expensive heating source than electricity.

Over half of MH's space-heating customers rely on natural gas, while the rest primarily depend on electricity. Until the May 1, 2008 Centra rate changes, electricity was the higher cost option where natural gas service was available for space heat. However, natural gas commodity prices are linked to oil prices, and oil prices have increased from the range of $15 U.S./barrel in 1999 to over $140 U.S. in recent months; while some observers suggest oil prices could reach $200 U.S./barrel within five years prices have recently moved to below $130, still basically twice last year's level.

As to natural gas, it is becoming a world-traded commodity, priced by the markets on a supply and demand basis, as is oil. The advent of LNG, liquid natural gas, and the coincident ability to transport natural gas between continents, has further increased the risk that natural gas will follow the oil price curve and out-price itself relative to electricity in Manitoba. In jurisdictions where market prices prevail, the prices for electricity produced by natural gas, coal and nuclear are rising. This increases the demand (and price of) for natural gas as a direct heating source. Consequently natural gas heating in Manitoba becomes less attractive relative to electric heating.

Assuming that full conversion of heating from natural gas to electricity may be expected to cost in the order of $3,500 (assuming the customer has 200 amp service), the payback period for conversion to electric heat would be fairly lengthy at current price differentials. However, once the change is made a customer is unlikely to reverse that decision; fuel switches are essentially permanent.

A larger risk rests with the initial selection of a space-heating source with new construction. And, as to existing customers, they need not switch entirely from natural gas to electricity to affect the domestic electricity load. At a lesser level, customers may increasingly supplement their natural gas heating by electrical sources (electric base board heating and small electric space heating units) as natural gas prices outpace electricity prices.

Recently a surge and continued volatility in and with natural gas prices has brought about suggestions of subsidies or monetary transfers from MH to Centra in order to limit the rate impact on residential natural gas heating costs. The support for such action is based on:

- Limiting the degree of fuel switching from natural gas to electricity for heating and thus avoiding the loss of favourably priced export sales which may also provide a net reduction in GHG emissions;
- Cushioning the majority of Manitoban from the full impact of soaring natural gas prices on their winter heating bills; and
- Limiting the extent of fuel switching in older residential areas that lack of adequate distribution networks to service broad scale electric heating loads.

The counterargument on cross-subsidizing natural gas vs. electric heating is as follows:

- Paying subsidies to natural gas heating in order to limit electric heating does not necessarily result in economic gains for MH from exports. Residential electricity rates are typically higher than average export prices. The net GHG reductions for displacing natural gas generation in the U.S. are only nominal; displacement of coal generation is not assured;
- Having domestic customers pay more for electricity in order to maintain current levels of natural gas consumption by Centra may keep MH whole, but implies that the electricity customer should subsidize Centra’s natural gas imports as well as MH’s electricity exports;

- Moving costs from natural gas customers to electricity customers distorts the market economics. In the absence of cost causation, the issue becomes how to limit the subsidy if natural gas prices rise to $15 U.S. /GJ or $20 U.S. /GJ the need for a subsidy becomes greater and at some point the subsidy from power becomes unmanageable.

10.2 Energy Supply

10.2.1 Hydraulic Generation

MH's hydraulic generation resources consist of:

- Lower Nelson hydraulic stations - 3,670 MW (HVDC transmission) with dependable output of 13,780 GW.h and a high flow output of 26,690 GW.h.
- Upper Nelson hydraulic station - 350 MW (AC transmission) with dependable output of 2,260 GW.h and a high flow output of 3,000 GW.h.
- Saskatchewan River hydraulic station -479 MW (AC transmission) with dependable output of 1,320 GW.h and a high flow output of 2,520 GW.h.
- Winnipeg River hydraulic station - 582 MW (AC transmission) with dependable output of 2,300 GW.h and a high flow output of 4,410 GW.h.

Overall, MH's hydraulic generation output is 19,750 GW.h under dependable flow conditions, and 36,690 GW.h under high flow conditions. Although these generation forecasts assume normal water flows are not augmented by drawing water from reservoir storage, MH does use energy-in-storage to arrive at a dependable flow output of about 21,000 GW.h (representative of 85% of base domestic load).

In median flow years (i.e., approximately 50% of the time), MH's hydraulic output is expected to be 29,500 GW.h, while in mean flow years (i.e., on the average based on 94 years of experience), hydraulic output is 29,100 GW.h. These outputs cover about 115% of base domestic load, providing the opportunity for entering into firm export commitments.

10.2.2 Augmented Flow Programs

MH employs augmented flow programs to optimize hydraulic generation output at the various plants. These programs typically involve compensation through direct payments and/or energy offsets with other jurisdictions (Saskatchewan and Ontario), or to First Nations and other to Manitoba communities.

Examples of an augmented flow program include:

- The augmented flow program on the Churchill River Diversion system allow increased additional flows by up to 5,000 cfs, annually by the approval of the Provincial Minister responsible. Deviations from the original license were offset by mitigation projects and compensation payments with respect to the communities of South Indian Lake, Nelson House, City of Thompson and town of Churchill.

- The Lake St. Joseph project, in conjunction with the Lac Seul project in northwestern Ontario, utilizes flow storage and releases that augment Winnipeg River flows by up to 9%. Under the agreement with the Lake of the Woods Control Board, MH compensates Ontario Hydro for the additional energy values.

In response to MKO interrogations, MH has provided information on a proposed water regime modification, not yet implemented, where Saskatchewan Power would be compensated for seasonally adjusted outflows from Reindeer Lake and Churchill River, controlled by the Island Falls G.S. to the benefit of MH. According to MH, Saskatchewan manages Reindeer Lake's water level to meet Saskatchewan Power's needs at its Island Falls G.S., and that potentially extra flow in the summer could be made available to MH.

MH's review to-date has not determined whether there would be any economic benefits to arise from such a flow modification. Nor has MH explored the level of compensation or mitigation that would be required from upstream or downstream affected parties.

10.2.3 Thermal Generation

To support and back-up MH's hydraulic generation, and to meet domestic load and firm exports commitments, MH relies on thermal generation:

a) Brandon Unit #5 (coal-fired), 105 MW with a maximum output of 837 GW.h.;

b) Selkirk Units #1 and #2 (natural gas), 126 MW with a maximum output of 1,060 GW.h.; and

c) Brandon SCCT, two units (natural gas), 298 MW with a maximum output of 2,400 GW.h.

The plants can provide about 4,300 GW.h/year, if fully utilized. When the Brandon coal generation is removed from full service and related to "emergency use", pursuant to a government directive related to mitigating climate change, maximum thermal output will decline to about 3,500 GW.h/year. At the present time, combining thermal and hydraulic generation provides for 100% of base domestic load.

MH rarely uses its natural gas generation plants, as such generation is uneconomic when natural gas prices are above $5 CDN/GJ. With natural gas prices currently in the range of $8-11/GJ, imports of power from the MISO market may be used instead. It is assumed that these imports come from natural gas rather than coal generation.

MH currently relies on its coal generation to provide support to hydraulic and wind generation in meeting export sale commitments. On an incremental fuel cost basis, coal generation is economically viable and contributes $10-20 million a year to MH's annual net income, in a median flow year.

The availability of the Brandon coal generation during the 2002 – 2003 drought saved MH approximately $50 million; the government has indicated that he Brandon coal plant will still be available for use in emergency conditions in the future.

The energy deficit in the MISO market caused by the Brandon coal plant closure may well be filled by additional coal generation; Sask Power or Ontario Hydro in summer and MISO region coal plants in winter. These sources if available are likely to be lower priced than natural gas generation.

10.3 Wind Generation

MH currently purchases 100 MW of wind energy from a private energy firm. The power is generated at St. Leon, Manitoba and has had a capacity factor of approximately 39%, as expected wind speed and direction are neither constant nor consistent. With forecast annual output of 320 GW.h, to be drawn on in conjunction with hydraulic generation, wind is deemed to be dependable energy.

The St. Leon wind farm has now been operational for almost three years; providing a reasonable but still limited track record for defining on-line availability of dependable energy. Though MH has cited commercial confidentiality reasons for not disclosing the operation's specific operational profile, apparently there have been some wind downtimes due to cold temperature conditions that have fallen outside the design operating range.

Another 300 MW (900 GW.h) of wind generation is to be added by 2013/14, assuming reported ongoing contract negotiations with non-utility generators lead to acceptable terms, including pricing. And, a further 600 MW is to be considered at some time in the future, although MH has expressed concern about a declining energy value of wind as related to the energy integration process of moving wind generation into the Manitoba grid.

The recent movement of MH toward new major export commitments raises the possibility that more wind generation could have positive market values. In the long-term, MH may achieve greater transmission inter-tie capabilities allowing the export of more wind and hydraulic blended energy.

As MH's anticipated 2,000 MW of new generation projects come online to meet domestic load growth and export opportunities, the limited level of then-remaining untapped hydraulic generation may have to be supplemented. More wind may well be the choice.

As the pending restriction of the Brandon coal generation plant operation by 2012 will remove 800 GW.h from MH's power resources, wind energy may now be worthy for consideration as a cost effective replacement.

10.4 New Generation and Transmission

MH is proceeding with the Wuskwatim Generating Station with a targeted in-service date of 2012/13. An Agreement has been reached with WPLP for purchase of all output, estimated to be 1,515 GW.h on average. This arrangement is expected to provide a 1,220 GW.h increase in MH's dependable power (4%).

The replacement of the Pointe du Bois G.S. on the Winnipeg River with a new plant is expect to achieve a 150 GW.h/yr increase in the dependable flow output upon the expected 2016/17in-service date for the new plant, and would add 300 GW.h/yr to average flow plant generation. The planned Kelsey rerunnering will not increase dependable flow output but will increase the average energy output of the plant by 350 GW.h/yr.

Bipole III is slated to be in-service in 2017/18, and is expected to add 442 GW.h/yr to MH's dependable generation, this by reducing transmission losses on the HVDC system. The loss reduction could be 1,000 GW.h under average flow conditions, based on the existing Upper Nelson generation plant.

MH's 2007/08 Power Resource Plan indicates that by 2017/18 total generation plant output under a dependable flow scenario will be 28,845 GW.h, equal to base domestic load. At that point, and until Conawapa and Keeyask G.S. are constructed, exports would have be supplied from domestic load reductions, through DSM and by imports or MH natural gas generation.

The Power Resource Plan calls for Conawapa G.S. to come on-stream in 2021/22, but Keeyask G.S. had then not been scheduled. And, a number of new pending export contracts were not included in the Power Resource Plan, those being:

a) 375/500 MW sale to NSP (estimated 1,600/2,000 GW.h);

b) 250 MW sale to Minnesota Power (estimated 1,000 GW.h); and

c) 500 MW sale to Wisconsin Public Service (estimated 2,000 GW.h).

Essentially, these additional export sales, if consummated, commit MH to export 5,000 GW.h/yr firm on-peak (5 x 16) power and require the development of both Keeyask and Conawapa, in close succession, and to be in place by about 2020. In the absence of Keeyask, MH's dependable domestically generated energy of, then forecast to be, about 30,000 GW.h would just cover forecast 2022/23 base domestic load. In such a case meeting the new export commitments would require further domestic load reductions through DSM savings and additional imports or MH natural gas generation.

If either space heating conversions from natural gas to electricity occurred or new large industry or large industry expansion drew power, the situation would be more problematic.

The addition of Keeyask Generating Station and Conawapa would have the following impact on the generation available from the Lower Nelson and the loads to be:

Forecast Future Lower Nelson Power Supply in 2020 GW.h				
Flow Condition	**MW**	**Dependable**	**Average**	**High**
Conawapa (2020)	1,300	4,550	7,050	9,000
Keeyask (2018	600	2,880	4,400	5,000
Total New Plants	1,900	7,430	11,450	14,000
Total Existing Plant	3,560	13,770	21,350	26,130
Total Low Nelson	5,460	21,200	32,800	40,130

MH has identified a transmission loss reduction of 442 GWH for a west-side Bipole III at current dependable energy levels. On a relative basis, the loss reduction at current average flows would be about 1,000 GWH. This level of reduction would, if moved to the export market, contribute significantly towards the annual carrying charges of the $2.2 billion investment in Bipole III and with Keeyask G.S. online the revenue contribution would be considerably larger.

Hypothetically on a relative basis for an East Bipole III that average flow scenario loss reductions would have been an additional 300 GWH. In 2022 after Keeyask and Conawapa G.S. come into service, the loss differential would be about double that amount.

With Bipole III in place and both Keeyask and Conawapa on line, MH has suggested that additional transmission may be required presumably to lower transmission losses. This could further affect capital spending plans.

10.5 Alternative Fuels and Energy Supply

Notwithstanding the recent pursuit of DSM (to reduce domestic load growth) and additional wind resources, MH has not been aggressive in pursuing other energy sources. This, in large part, relates to the relatively high cost associated with alternative sources of generation in comparison to MH's current costs and rates.

In justifying alternative energy sources, MH has to look beyond the current demand-supply economics to additional considerations, including environmental and social issues, when considering:

- Residential and general service DSM initiatives, with the average domestic rate higher than the average export price and with residential rates higher than general service rates;
- Wind costs (prices now similar to peak export prices, (i.e. in the range of 9 cents per kW.h);
- Bio-mass costs (above peak export price);
- Solar costs (currently estimated to be well above peak export prices);
- Geothermal (lost revenues and embedded costs may exceed export revenues, particularly during off-peak);
- Non-utility Generators (lost revenues and embedded costs may exceed export revenues);
- Brandon coal generation restrictions (higher prices for replacement energy) could approach $20 million a year; and
- Bipole III - West Side (no offsetting revenue for higher capital cost, reduced savings on transmission losses) and higher risk in the expected rare case of an outage of Bipole I and II.

10.6 Greenhouse Gas Emissions

MH's GHG 2005 emissions from electricity operation were reported to be about 650 kilotonnes of CO_2 equivalent. The Brandon Coal Thermal Generation station, on average, accounted for 550 kilotonnes of the total, while generating about 500-600 GW.h/year of electricity. Closure of the plant would result in net reductions of about 300 kilotonnes of $C0_2$ if the replacement energy source is natural gas based.

Converting from coal to natural gas generation would reduce CO_2 emissions by about 60%, but the costs involved would equate to about $120/tonne of CO_2. Theoretically that leads to a strictly economic conclusion that continues to favour operation of the coal plant, though buying carbon credits could reduce its economic profitability.

Electricity exports into the MISO market in 2005/06 were 9,800 GW.h and required 2,000 GW.h of imports, to arrive at a net export of 7,800 GW.h. If this level of net exports displaced American natural gas generation, the indirect GHG savings would have been about 2,500 kilotonnes; if the exports displaced some coal generation as well as natural gas, the CO_2 reduction would have been up to 50% higher.

In 2005/06, MH reported indirect GHG reductions of 738 kilotonnes arising out of deemed DSM energy savings of 1,030 GW.h/yr. MH's estimate is consistent with an assumed 50% natural gas/50% coal generation displacement.

Because 2005/06 involved record hydraulic generation of 36,200 GW.h from exceptionally high water flows, GHG reductions in that year actually resulted from surplus hydraulic generation and not from the DSM initiatives, as there was no additional energy export from DSM possible as tie-line and other transmission constraints limited both exports and total hydraulic generation in 2005/06.

10.7 Interveners' Positions

None of the interveners challenged MH's load growth assumptions, its portrayal of the existing supply situation, or MH's identification of the consequences of increasing domestic load.

RCM/TREE is concerned about the negative consequences of continued low electricity prices, which, it holds, encourage greater domestic consumption and leads to lower exports, and hence lower GHG reductions in the U.S.

MIPUG would promote DSM activities encouraging the use of natural gas rather than electric heating, questioned the pending restrictions on the Brandon coal plant and questioned the rationale for MH's proposed new generation and transmission facilities, being built primarily to serve exports.

MKO suggested a need for what it would consider a more accurate reflection of the risk of fuel switching in MH's load forecast.

MKO recommended that, as one test to be applied to determine whether or not MH's costs are just and reasonable, the Board should require MH to ensure that wherever it is able to identify value from a change in its operation, for example the Augmented Flow Program, that MH be required to associate any adverse effects with justified mitigation and ensure that the projected adverse effects are fully identified, reported, accounted for and addressed. MKO suggested MH be required to provide full disclosure of augmented flow programs, and any related extra-provincial arrangements on water supply.

The basic issue of there being a financial risk associated with energy intensive industry expansion, as identified by MH, was not been challenged by the interveners. And, both the Coalition and RCM/TREE indicated strong support for MH's intentions to implement marginal cost pricing for new industrial loads not associated with strong Manitoba economic benefits.

MIPUG didn't dispute the premise of charging higher rates for some industrial loads, but disagreed with MH's proposed approach and placed a higher value on large industry's contribution to the Manitoba economy.

10.8 Board Findings

Load Forecast

Based on past experience and recent price increases and volatility related to natural gas, MH's future domestic load forecasts may prove to be low, with space heating by natural gas potentially now more expensive (leaving aside the cost of conversion) than by electricity.

With natural gas prices continuing to rise faster than electricity prices (2008-09 natural gas space heating costs may be considerably higher than was the case in 2007-08), and far more costly than was the case in 1999 when MH purchased Centra Gas Manitoba Inc., more new customers may opt for electric heat and existing natural gas customers may either convert to electric heat in greater numbers or supplement gas heating with electric baseboard or small electrical heaters.

The result would be greater domestic load and reduced opportunity for the export of electricity unless and until new generation is available.

While MH has acknowledged that there is a growing potential for customers switching from natural gas to electric space and water heating, it has not reflected the risk in its current load forecasts. MH should include an analysis of the issue and the risks with its next Load Forecast.

MH has not been attempting to influence customer fuel choice, taking the view that it is the customer's responsibility to assess the relative merits of the options. The approach taken represents an attempt by MH to remain neutral on the relative merits of electric and natural gas space heating.

However, given the financial and environmental issues at stake, MH should carry out a study to define the implications of fuel choice and take a more active role in assisting consumers in making choices, given seemingly ever-increasing energy costs, both in an absolute and as a percentage of disposable household income sense.

As MH enters into more export contracts with fewer remaining hydraulic sites apparently available, it is more likely that wind generation could have a greater prominence, and potentially-an increased market value. In light of the current wind generation project(s) developed and contemplated for development in the future, the Board requires additional information on the implication of MH's wind strategy on future consumer rates.

Accordingly the Board will direct MH to submit a report to the Board on January 15, 2009 on the 300 MW additional wind energy project(s) and a discussion of the business case, wind strategy, prospects and timelines for this project, as well as the further 600 MW moving toward the government's target of 1,000 MW of wind energy. The Board will also require access to the agreements for the existing 100 MW St. Leon wind project, and an opportunity to review the pending agreements for the 300 MW project(s).

MH's recent announcements of new power sales into the U.S. have possibly precluded further firm energy contracts, as the Utility's dependable hydraulic energy has been largely committed. This suggests that, at least in the relatively immediate future material energy sales to Ontario, Saskatchewan and even Alberta may have to be non-firm and primarily off-peak. What this says with respect to the merits and prospects for an east-west national electricity grid is a subject for conjecture.

If GHG emission reductions are seriously targeted for achievement in Canada and the U.S., MH's available energy should gain value. It is important for MH to negotiate prices providing for escalation in certain circumstances, such as further increases in oil, natural gas and coal prices, and increased attention to emission reductions (by way of cap and trade or carbon taxes).

The decision to place Bipole III on the west side of the province involves major additional costs, when construction costs, transmission losses, and reliability considerations are included. A west side of the province location for Bipole III is favoured by government, giving consideration to a hoped-for and possibly pending designation of a large sector of boreal forest East of Lake Winnipeg as a World Heritage Site. The avoidance of major development in what is deemed one of the last undeveloped large areas of boreal forest in the world has, at minimum, intrinsic value, and is consistent with recognition of the overall climate change issue and the responsibility of governments to mitigate known and expected effects.

The westerly route, while traversing similar terrain over a greater distance than the rejected eastern route, is not expected to face the same constraints that an eastern route would encounter in seeking environmental and community approval. The west side of the Province is already developed to a significant degree, and may face less opposition to the construction of a new transmission line.

As sole shareholder of MH, the Province has the right to direct the west side routing. Yet, it should be acknowledged that the additional costs will be borne by Manitoba ratepayers, either in the form of higher rates in the longer-term or a reduced export "subsidy" reflected in rates. Export contracts are price competitive and, in the absence of CO_2 taxes, coal generation costs will largely dictate future energy prices negotiated in the MISO market.

As such, the added costs for Bipole III is unlikely to be reflected in the energy sales price, although, and this is an important consideration, ”clean hydro” power may eventually command a premium price and MH’s future sales may be made “easier” by its environmentally-friendly route choice.

For MH, the development of alternative energy in its export markets may tend to reduce energy demand from MH. As well, alternative energy sources that may come into use in the future in Manitoba may well affect domestic consumption and revenues, without a corresponding reduction in the need for infrastructure and services. While MH is a significant revenue generator, its margins are low (particularly if the cost of new construction is considered), and rates are likely to be under continued upward pressure going forward.

Given that MH is incurring costs for environmental and social purposes (i.e., West Side Bipole III; Brandon Coal Plant, etc.), such costs should be separately defined and tracked to allow for subsidies and for the cost of choices made for environmental objectives to be transparent.

As noted in the findings for MH’s capital expenditures, new export agreements are driving MH’s construction of new hydraulic generating stations. The underlying economics have not been publicly disclosed or tested. Because of the potentially negative impact on domestic consumer rates, at least in the initial years, the economic justification of expansion presented on export agreements should be reviewed and approved before such export agreements are finalized.

The Board is of the view that it would be in the public interest that MH’s export contracts be filed with the Board for review, and possible approval.

There does not appear to be any clearly-defined process that MH follows in achieving augmented flow projects. Parties potentially affected by such a program might be better served if a publicly-known approval process were in place. The Board will direct MH to provide a summary of existing programs and potential future programs defining the arrangements for increased or modified (augmented) water flows within and external to Manitoba. They should include the specifics of the program and mitigation and compensation related thereto.

11.0 Demand Side Management

11.1 General

MH's Demand Side Management (DSM) initiative, "Power Smart" consists of energy conservation and load management activities designed to lower the demand for both electricity and natural gas in Manitoba. The most current plan is the 2006 Power Smart Plan.

For the electric business, the initiative is one element of the resource options available for meeting the Province's electrical needs and the initiative plays an important role in the Corporation's overall integrated resource plan. DSM initiatives are to assist customers in meeting their energy needs through energy efficient measures. For the electric business, such initiatives enable MH to serve more domestic customers with less energy. Reduced domestic load requirements allow for reduced capital expenditures and increased energy available for export. Electric DSM initiatives are evaluated utilizing the same underlying criteria and economic evaluation approach as used with alternative resource options.

11.2 Program Evaluation

To evaluate new programs a high level assessment Marginal Resource Cost Screen compares the expected benefits to the incremental capital costs. If programs pass the initial screening, a more detailed assessment is undertaken involving developing program concepts and designs and projecting costs and benefits.

MH determines the cost effectiveness of DSM programs using the Total Resource Cost and Rate Impact Measure Tests. The primary economic indicator for evaluating the effectiveness of both electricity and natural gas incentive-based programs is the Total Resource Cost (TRC) test. TRC measures the cost effectiveness of a product or program, and a TRC benefit/cost ratio greater than one (>1.0) indicates that a program is cost effective.

The secondary economic indicator for evaluating the effectiveness of programs is the Rate Impact Measure (RIM) test. RIM indicates the cost effectiveness of a program from the utility's perspective. All DSM related savings and costs incurred by the utility, including revenue loss and incentive payments, affect the RIM benefit/cost ratio. The results provide an indication of a program's expected long term impact on rates.

As a guideline, MH attempts to design electricity based DSM programs that have a RIM of 1.0 or greater. However a program with a RIM of less than 1.0 may trigger a program redesign, and may still proceed if the program design is judged to provide overall benefits.

Once Power Smart programs are in place, they are evaluated to determine the net program load savings and costs as well as the cost-effectiveness of the savings. Net savings take into consideration factors such as free riders (benefits derived that carry no specific cost), heating and cooling interactive effects, and system peak coincidence and persistence effects. Customer data and market information are used to assess the impacts of these factors on the overall savings attributable to incentive-based Power Smart programs.

In evaluating DSM programs, MH attributes no value to delayed generation in its TRC test, nor does it consider the full benefit of displacing carbon in export markets.

11.3 Program Costs and Amortization

MH plans to spend $401 million over the next 11 years on DSM expenditures. Of that amount, MH budgeted to spend $38.3 million in fiscal 2008-09, a figure later revised at the hearing to $43.1 million.

MH plants to spend a cumulative amount of $571 million on DSM expenditures through to the end of the 2017/18 fiscal year. While one purpose for spending on DSM is to delay new generation, new generation has, to date not been delayed due to DSM.

MH has defined "levelized" costs for various DSM initiatives. The following table provides insight as to the cost effectiveness of various activities and programs.

Exhibit 4.3.2.5
Electric Levelized Utility Costs
¢/KWh Saved by Incentive-Based Power Smart Program

Program	Results 2005/06
Efficiency Programs:	
1. Residential	
New Homes	7.2¢
Home Insulation	2.8¢
Compact Fluorescent Lighting	0.8¢
LED Lighting	6.6¢
2. Commercial	
Commercial Construction and Renovation	1.1¢
Internal Retrofit	1.8¢
Commercial Lighting	1.7¢
Agricultural Heat Pads	0.4¢
City of Winnipeg Agreement*	7.7¢
3. Industrial	
Performance Optimization	0.3¢
4. Discontinued/Completed Program Costs	N/A
Efficiency Programs Costs Subtotal	1.0¢
Rate/Load Management Programs:	
Curtailable Rates**	N/A
Overall: Program Costs	1.0¢
Overall: Program + Support Costs***	1.1¢

* The levelized cost of the electricity savings estimate is being associated with the City of Winnipeg's Power Smart Agreement is 7.7¢/kW.h.

** Levelized cost analysis is not provided for rate/load management programs.

*** Support costs only include incremental support costs, no customer service initiatives or standard costs are included.

MH identified that its calculation of cents per kilowatt hour saved was based upon current program kilowatt hour savings, and assumed generation over a thirty (30) year planning period.

MH amortizes its DSM costs over an average 15 year period, which is longer than other comparable utilities. BC- Hydro and Quebec Hydro amortize DSM cost over a maximum 10 year period. While MH states that their policy is fully supportable. The Board has expressed reservations in past Orders and has suggested that MH could express such costs over a shorter time frame.

The unamortized balance of DSM expenditures was $17 million as of March 31, 1994, and is forecast to grow to $180 million by the end of the 2008/09 fiscal year. The amortization of DSM expenditures was $978,000 in fiscal 1993/94, to increase to $13.7 million in the fiscal year ending March 31, 2009.

MH has not yet determined the effect IFRS will have on its accounting treatment of DSM expenditures.

11.4 DSM Program Savings

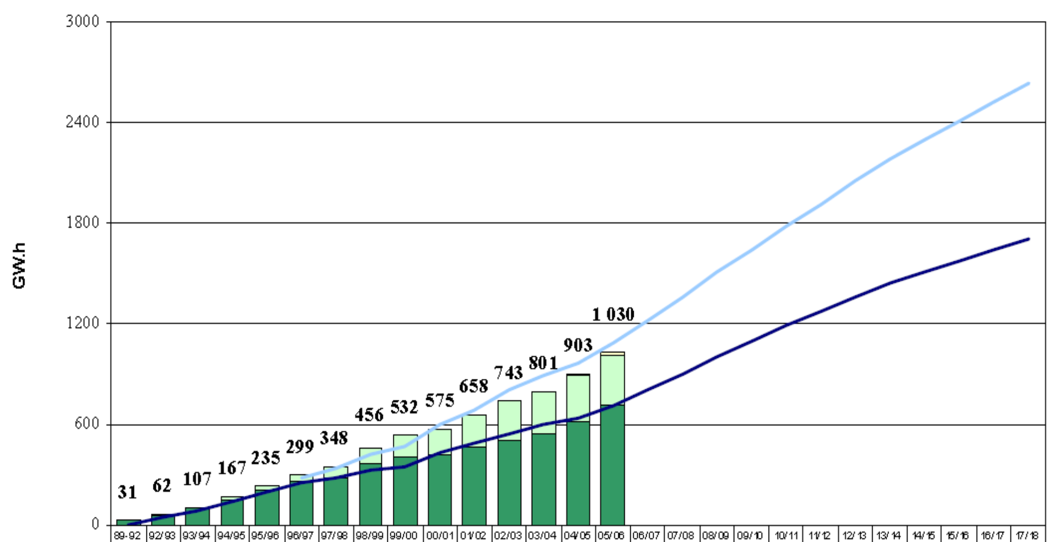
By the end of 2005/06, MH opined that its Power Smart Programs would achieve an annual load reduction of 1,030 GW.h in energy, and 434 MW in winter peak demand (at generation), and that this level of "saved power" translated to a cumulative reduction of over $214 million in customer bills, and indirect greenhouse gas emission reductions of approximately 738,000 tonnes of carbon dioxide equivalent emission (the latter in 2005/06 alone).

Domestic energy reductions contribute to surplus generation capacity, which contributes to energy sales in the export market. The cumulative energy and demand reduction achieved (including savings to date) through the Corporation's DSM efforts is on target to achieve 2,695 GW.h/year of energy savings and 848 MW by 2017/18. MH also has a plan to achieve natural gas savings of 101 million cubic meters.

In total, the programs are expected to result in greenhouse gas emission reductions of 2 million tonnes by 2017/18.

The following table depicts energy and demand savings realized to fiscal 2006, and that forecast through fiscal 2018:

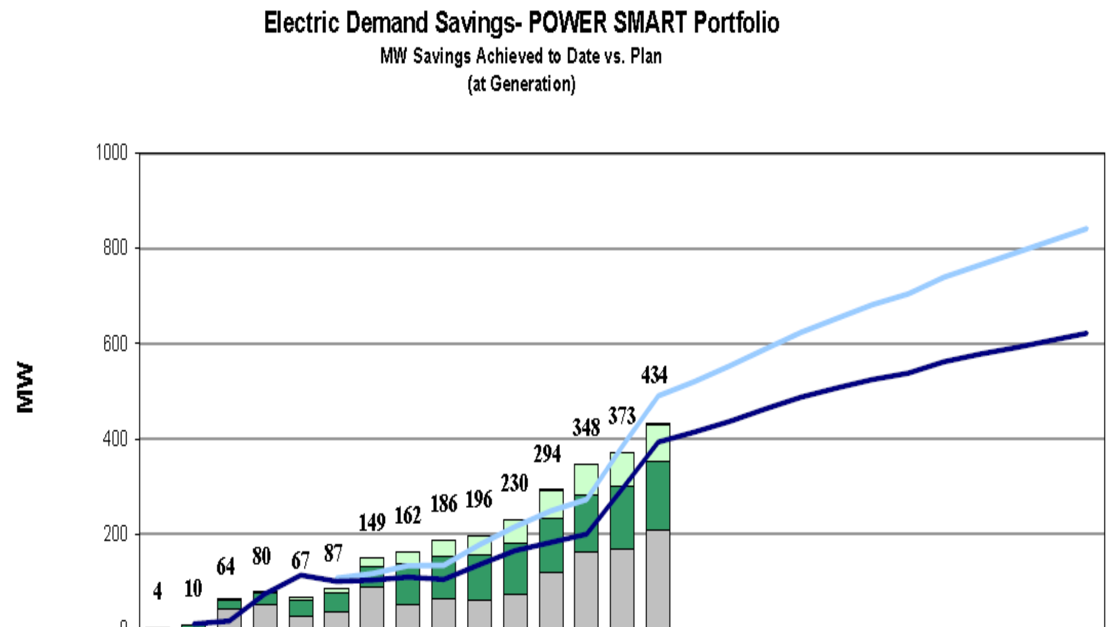
Electric Energy Savings - POWER SMART Portfolio
GW.h Savings Achieved to Date vs. Plan
(at Generation)



	89-92	92/93	93/94	94/95	95/96	96/97	97/98	98/99	99/00	00/01	01/02	02/03	03/04	04/05
Customer Service Initiatives											2	4	7	10
Codes and Standards	0	2	8	16	25	40	63	93	125	156	189	228	248	274
Incentive-based-Efficiency	31	59	99	151	209	259	285	363	407	419	467	511	546	619
Total Achieved	31	62	107	167	235	299	348	456	532	575	658	743	801	903
Plan	0	50	86	138	195	252	279	327	350	435	491	544	603	634
Plan incl. Planned Codes & Standards						281	336	422	466	602	686	810	891	970

	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18
Customer Service Initiatives	18												
Codes and Standards	298												
Incentive-based-Efficiency	714												
Total Achieved	1030												
Plan	713	803	901	1000	1095	1186	1271	1360	1446	1514	1579	1642	1706
Plan incl. Planned Codes & Standards	1088	1220	1361	1506	1644	1783	1915	2051	2183	2296	2410	2523	2637

11.0 Demand Side Management



	89-92	92/93	93/94	94/95	95/96	96/97	97/98	98/99	99/00	00/01	01/02	02/03	03/04	04/05	05/06
Customer Service Initiatives											1	1	2	3	3
Codes and Standards	0	1	2	4	6	10	15	23	32	40	49	59	64	70	76
Incentive-based - Efficiency	4	10	17	26	34	41	46	86	91	93	105	113	119	131	146
Incentive-based - Rate/Load	0	0	45	51	27	36	88	53	64	63	75	121	163	169	208
Total Achieved	4	10	64	80	67	87	149	162	186	196	230	294	348	373	434
Plan		12	18	75	114	101	104	110	105	136	166	183	200	296	394
Plan incl. Planned Codes & Standards						108	118	134	135	178	216	249	273	385	491

	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18
Customer Service Initiatives												
Codes and Standards												
Incentive-based - Efficiency												
Incentive-based - Rate/Load												
Total Achieved												
Plan	414	437	463	488	507	525	538	562	578	592	607	622
Plan incl. Planned Codes & Standards	520	553	589	624	653	682	705	740	765	791	816	842

The tables suggest that MH's DSM initiatives are running at about 90% of target. Incentive-based programs, which are individually tracked, run above 95% of target, but Codes and Standards programs, which have not been specifically defined, are running at about 80% of target.

DSM has managed to offset about 20% of otherwise domestic load growth and freed-up additional energy for export. However, it does not appear to have delayed the Wuskwatim G.S. in-service date.

MH claims to have reduced GHG indirectly by 730 kilotonnes on a cumulative basis, due to reduced emissions resulting from their export of electricity.

MH acknowledged that the estimated GHG benefits have no tangible financial benefit for MH.

11.5 City of Winnipeg DSM Program

As a condition of MH's acquisition of WH, MH and the City of Winnipeg entered into a Power Smart Agreement on September 3, 2002. The objective was to capture energy efficient opportunities within the City's facilities, with a minimum target of reducing the City's energy bill by $800,000 annually. MH guaranteed the City an annual savings of $800,000 from the measures or the equivalent in the form of deemed savings plus a monetary payment by MH. MH's commitment over the ten year term this condition applied had a total value of $8 million.

A variety of energy efficient measures have been implemented for new construction and renovations in a large number of City owned or operated facilities towards meeting the objective of the program.. The energy savings forecasted to be achieved is 12.3 GW.h, a goal to be limited to a 20 year time horizon.

The estimated annual saving achieved by the City of Winnipeg related to the agreement is as follows:

Contract Year, ending August 31	**Savings ($)**
2003	607
2004	65,175
2005	144,426
2006	654,239
2007	771,905
2008 (forecast)	850,000
2009 (forecast)	900,000

To the end of 2007/08, MH has paid $2.4 million to the City, this because it could not deliver the $800,000 of annual DSM savings each year as prescribed in the agreement with the City.

So far, including the $2.4 million paid, MH has spent over $10.3 million under the agreement, exceeding the ten-year commitment of $8 million of savings and/or payments. MH states that the levelized cost of the program has been the equivalent of 7.7¢ per kW.h.

MH stated that due to the energy savings realized from the initiatives undertaken, MH is economically better off, as the energy saved has been and may be exported to the United States.

11.6 Carbon Trading

In 2002, MH became a founding member of the Chicago Climate Exchange (CCX). CCX requires participants to reduce emissions relative to historic baselines. Each participant is provided an annual allowance (of CCX units), an allowance that decreases each year from the historic baseline. If a participant's emissions exceed their allowance, the participant is required to buy additional units through the exchange. Conversely, if their emissions are below their allowance, they are able to sell the surplus units.

Through participation in this CCX, MH gains experience with the measurement, reporting and trading of admissions. Export sales, for which MH negotiates ownership of the associated emission reductions, make up a significant component of the offsets earned. While having these reductions delivers real value in complying with the voluntary commitment, surplus reductions may not yield additional value.

MH reported its intention to continue to monitor emerging market rules for opportunities to extract value from its emission reductions achieved in either Manitoba or in the Corporation's export market.

11.7 Low Income DSM Program

In its 2006 Power Smart Plan, MH included a new residential program, the "hard to reach" (HTR) program. The HTR program targets low-income residential households on an integrated basis (i.e. for both natural gas and electric consumption). The program has since been modified and now integrates funding made available by the federal government's ecoEnergy program. The current design of the low-income program was implemented December 14, 2007.

MH's Lower Income Energy Efficiency Program is designed to bring Power Smart and energy efficient measures to an estimated 4,600 lower income households over the next three and a half years ending 2010/11. The program targets lower income Manitoban homeowners and tenants.

In the case of lower income tenants, an agreement must be reached between MH and the landlord/building owner in order that a substantial portion of the benefits associated with retrofit measures funded by MH's program will be passed on to tenants. Private landlords and non-profit social housing organizations, including Manitoba Housing Authority (MHA) public housing and other non-profit subsidized housing organizations, are eligible to participate in the program.

Eligibility for households pursuant to the program was established by the Corporation at 125% of the Low Income Cut-off (LICO) established by Statistics Canada. Targeted measures to be addressed by the program include:

- low or no-cost basic energy efficiency measures, such as compact fluorescent lights;
- faucet aerators, low-flow showerhead, pipe wrap, hot water tank set back, and caulking/air-sealing;
- insulation for basement, attic and crawlspace installation; and
- High-efficiency natural gas furnaces.

Energy Efficiency Measures	**Assumptions**		
	Ave. electric Savings Per Home* (kw.h.)	Net to Gross Adjustments (Persistence Factor)	Participation
Insulation: including attic, basement and crawlspace	2,797	100%	Attic: 84% Basement: 58% Crawlspace: 8%
Compact Flourescent Lighting (6 CFLs per home)	138	90%	100%
Drainger	162	100%	18%
Water Measures: including tank set back, 1-Low-Flow Showerhead and 2-Faucet Aerators, pipewrap	404	Tank set back: 50% Showerheads: 90% Aerator: 90% Pipewrap: 95%	50% 100% 100% 100%
Weatherization: including air sealing and gasket covers	640	100%	100%

*- includes single detached homes, town houses, multiplexes and mobile homes

The anticipated duration of MH's Lower Income Program is tied to the Federal government's ecoEnergy program, which is currently approved to operate until March 31 2011. Contemplation of changes to the existing program will be undertaken closer to the date of the end of the Federal funding commitment.

MH intends to deliver the program through both Community Based Organizations (CBO) and individual household participation. Both approaches require pre- and post-audits, to identify energy efficiency opportunities and verify work completion.

The cumulative budget through fiscal 2017/18 for MH's Lower Income Program is $12.6 million, including rate-based, federal and Affordable Energy Fund (AEF) funding; the program's budget for 2008 was reported to be:

Program	**Budget (millions in 2008$)**
AEF Low Income - Electric Component	$3.5
AEF Low Income – Natural Gas Component	$6.1
AEF Total	**$9.6**
Power Smart Low Income – Electric	$1.1
Power Smart Low Income – Natural Gas	$1.9
Total Low Income DSM	**$12.6**

In assessing the economic benefits associated with the Lower Income Program, MH determined that the TRC for the program is 0.9, the RIM, 0.7, and the levelized cost of the program, 11.2¢ per kW.h. The results of testing indicate that the program results in some degree of cross-subsidization (of lower income customers by other residential customers).

11.8 The Affordable Energy Fund (AEF)

Following a spike in oil and natural gas prices in the summer and fall of 2005 on the heels of hurricanes Katrina and Rita, which damaged energy availability from south-east American production and distribution sites, and the Board's subsequent action as of November 1, 2005 when it deferred costs and restrained natural gas rates for Centra Gas' residential customers to recognize what the Board then-deemed to be a price bubble, the Provincial Government introduced

The Winter Heating Cost Control Act (which was subsequently passed, proclaimed and implemented in 2006).

Among other provisions, the Act established the Affordable Energy Fund [AEF], requiring MH to contribute 5.5 % of its fiscal 2006/07 gross export revenues to the AEF. This resulted in a fund of $35 million to be utilized for various energy efficiency initiatives, including if not primarily, assisting low-income electricity and natural gas customers.

MH indicated that $19 million of the AEF's $35 million was earmarked for province-wide low-income initiatives, with $8 million for community energy development, $0.25 million to expand the eligibility of Power Smart programs in Manitoba to include residential homes heated with energy other than natural gas or electricity, $0.75 million for rural and northern support and outreach, and $1 million for special projects then-yet to be defined.

MH indicated its intention that the $19 million reserved for low-income programs would mostly benefit electricity and natural gas space-heated homes, and would provide for programs that would not otherwise be funded from MH/Centra's rate-based DSM programs, including the Corporation's HTR Program.

In commenting on the establishment of the AEF at the most recent Centra GRA, in Order 99/07 the Board stated:

> "The Board notes Centra has indicated that the AEF is not slated to be credited interest on unused balances. Centra should impute interest income on AEF funds transferred to it, the proceeds to be utilized to underwrite additional or expanded low-income programs. Such an approach would also allow the funds available within the AEF to represent some measure of an endowment (the problem with the AEF is that it has been funded with a "one-time" transfer, while the work of upgrading heating efficiency and retention is likely to require more than a decade and cost more than the initial allotment of

> $19 million – which must address both electricity and natural gas low-income households)."

In Order 99/07 the Board directed:

> "Centra segregate funds transferred to it from the Affordable Energy Fund (AEF) and funds accumulated for the new Furnace Replacement Program, with such funds to earn interest at Centra's short-term borrowing rate."

MH has yet to act on the direction, responding that the AEF should not attract interest as it would result in an accumulation, before deductions for expenditures made, of more funds than were contemplated in the Act. MH stated having the fund attract no interest to be consistent with the legislation.

Recently, MH, in partnership with the Spence Neighbourhood Association initiated a pilot project. The next steps for the Corporation's province wide low-income program were reported to include continuing with the execution of private and community programs, and marketing and promoting in communities, rural areas, and other relevant venues.

11.9 Interveners' Positions

The Coalition

DSM Program Evaluation

The Coalition suggested that MH should think of DSM in a different way. Mr. Dunsky, who appeared on behalf of the Coalition, opined that the RIM Test should not be utilized to screen for justification of DSM programs, and that while the TRC should remain the primary test for DSM programs, under MH's current approach there will be proposed measures that will fail the TRC test that should still be pursued if they pass the "utility cost" test. The Utility cost test compares money invested in a program with the value of expected energy savings for the utility. For Mr. Dunsky, if MH can generate cost effective kW.hr savings, the program initiative should proceed.

Mr. Dunsky further stated that in evaluating low income programs it was extremely important to account for non-energy benefits (NEBs), noting that a growing body of evidence points to very significant NEBs arising from low-income programs. Mr. Dunsky suggested that NEBs include fewer shut-offs, reduced emissions and health and safety benefits. Mr. Dunsky recommended that the Corporation take into account NEBs in its future cost-benefit analyses of low-income programs.

The Coalition recommended NEBs be included in the screening of potential DSM programs. The Coalition further recommended that either an independent or an internal review of MH's current DSM portfolio be undertaken, and that the review consider the screening tests, portfolio of programs and NEBs.

Low-Income Programs

Mr. Dunsky observed that consumers face an array of market barriers to the adoption of cost effective energy efficiency products and practices, and suggested that the barriers are most acute for low-income customers. Mr. Dunsky cited that barriers such as information and search costs and below average language and computational skills (literacy, poor math skills, English as a second language) represent significant hurdles to both participation in DSM programs and adoption of efficiency measures.

Mr. Dunsky also cited performance uncertainty and higher than average housing mobility for low-income consumers (multiple moves within a short period of time) adds to the uncertainty regarding the economic value of long-term energy savings measures for low-income households. He also cited transaction costs: and greater difficulty experienced by low-income households in dealing with complex transactions can also lead to lower measure uptake and higher dropout rates. And, of equal importance as operating barriers to the participation of low-income households in energy efficiency measures, Mr. Dunsky noted:

a) financing difficulties – a general lack of access (or access at unreasonable cost) to capital;

b) an aversion to debt due to the payments associated with debt;

c) a diminished ability to meet upfront costs;

d) the organizational practices of many contractors, unwilling to work for low-income customers or charging a premium for the perceived risk of non-payment; and

e) the daunting issue of split incentives in rental markets, whereby landlords are unwilling to pass on savings to tenants or invest in measures that would assist in lowering utility bills but not benefit the landlord financially.

Mr. Dunsky reiterated a concern previously expressed by the Board that generally low-income customers will lack access to the capital required to make improvements to the energy efficiency of their homes. He further noted that low-income individuals are often caught in a “vicious cycle of debt”, such that even if they could have access to capital, they will have an aversion for incurring debt requiring increased demands for their disposable income, and, therefore are unlikely to invest in their home (even if the investment would be in their long-term interests).

Mr. Dunsky suggested four key principles for success in administering a low-income program:

1. Keep it simple. Participation drops precipitously as complexity increases. Program implementers need to take “A-Z” ownership of the complexity involved in conducting audits, hiring contractors and overseeing work. Complexity should occur on the implementer’s side, not the participant’s. Similarly, proof of income and other eligibility requirements need to be flexible.
2. Keep it free. While it may be tempting and intuitive to request even symbolic participant contributions, Mr. Dunsky suggested that attempts to do so in other jurisdictions have generally met with failure.
3. Incent “sales” (outreach). For Mr. Dunsky, the difference between a good theoretical design and good performance is sales. Ideally, the utility, the contractor and other low-income stakeholders (supporters) will contribute to an active outreach effort, with only the utility and the supporting community having the capacity, tools and incentives to find potential customers and “close the sale”.
4. Be comprehensive. As with any sale, the hard part is getting in the door. Mr. Dunsky suggested that once a participant is in the program, it is critical to capture all possible opportunities, recognizing that any measures not installed will likely be lost for years and/or their savings will cost significantly more to achieve at a later date. Comprehensive programs typically include education, a suite of “light” measures (CFLs, caulking/weather-stripping, low-flow aerators and showerheads, etc.), envelope measures (insulation and weatherization) and appliance and equipment replacements (especially old fridges and furnaces).

Mr. Dunsky opined there were a number of major weaknesses in MH’s low-income energy efficiency program, beginning with the fact that the current program design is too complex, consisting of a number of hurdles that the low-income customer must overcome to participate. Mr. Dunsky noted that MH has not taken ownership of the delivery of its programs, passing the responsibility to low-income customers, an approach that he opined represents a serious barrier for low-income customers.

To assist in reducing low-income household resistance to implementing energy efficiency measures, Mr. Dunsky proposed that MH take full ownership of its DSM programs, including taking on all the necessary administration. He noted that in other jurisdictions where programs have been successfully implemented, full utility ownership of all approaches taken had been followed, with the benefits including the elimination of needless hurdles, the ability to negotiate better prices with contractors than can be achieved by individual low-income homeowners, and assurance of quality control.

Mr. Dunsky criticized MH's reliance on others, suggesting that relying on CBO's to identify and involve low-income customers is unlikely to secure success. Mr. Dunsky opined that another weakness in MH's program relates to the involvement of CBO's in program delivery. He recommended that MH be selective and choose only organizations with the institutional ability, reputation and capacity to deliver low-income programs effectively. He also suggested that MH invest significantly in helping CBO's develop the necessary capacities and abilities to deliver programs effectively.

Mr. Dunsky recommended that when such organizations are involved they be closely monitored and regularly assessed, particularly as to their ability to meet targets. For Mr. Dunsky, MH should measure and evaluate the time from "first contact to work completion", and both undertake quality control spot checks and utilize client satisfaction surveys.

To avoid the problems he expected to arise with involving CBOs in MH program delivery, Mr. Dunsky recommended that MH lead the projects and underwrite the costs of the measures required, dealing with the Federal government directly to recover any federal incentives that may be available.

The Coalition suggested that approximately 30% of MH's residential accounts pertain to rented homes, excluding duplex apartments, and that there are almost 98,000 apartment units. The Coalition noted renters' average household income is significantly lower than the Manitoba average, and that apartment units, where renters predominate, are currently excluded as a target group for the low-income energy efficiency program.

Mr. Dunsky stated that a major barrier faced by low-income customers is the lack of access to capital and a concurrent aversion to new debt. Mr. Dunsky also noted that the majority of low-income households are renters, and that a renter would not be willing to invest in improving the energy efficiency of a building if they were not to receive the benefit. Conversely, a renter responsible for the utility bill may find the owner of the building not willing to invest in improving the energy efficiency of the building envelope, because the landlord will not retain the benefits.

Mr. Dunsky stated that programs requiring landlord support should be made attractive for both the low-income tenant and the landlord, and that otherwise a low-income tenant will not benefit because of a lack of landlord participation. Mr. Dunsky proposed that MH offer a turnkey approaches, whereby MH would pay for all the measures undertaken and collect any external incentives. Mr. Dunsky indicated such an approach would best facilitate landlord participation.

With specific respect to natural gas furnace replacement, Mr. Dunsky indicated that MH's current program is inadequate. Mr. Dunsky suggested MH offer a zero-interest loan or, preferably, a lease. The loan/lease would involve owner payments over a maximum of 10 years.

He suggested that a leasing approach would allow repayment to remain tied to the furnace, the newer more efficient furnace to provide the energy savings benefits allowing the lease payment to be made. Mr. Dunsky also suggested that a more aggressive financing offer may overcome low-income customers' reluctance to participate, and provide an opportunity to replace inefficient furnaces (which result in high levels of emissions and bills).

Mr. Dunsky also suggested MH expand its current DSM program to include a fridge replacement program, which would target the early retirement of inefficient refrigerators. Mr. Dunsky estimated that replacing inefficient refrigerators could be expected to result in an average saving of over 900 kW.h annually for each fridge replaced.

Based primarily on its witness' testimony, the Coalition recommended, for Low-Income and Tenancy DSM:

1. MH provide turnkey service;
2. CBO capacities be evaluated prior to involvement;
3. A fridge replacement program be implemented;
4. A more aggressive approach to furnace replacement be undertaken; and
5. Expedite the rollout and implementation of low-income DSM programming, addressing costs, benefits, and sources of funding.

The Coalition did not endorse RCM/TREE's recommendation for a bill assistance program, stating that while the intervener was open to a further study of the issues involved, it had concerns with problems found in US jurisdictions, those reported to be related to low participation levels, and suggesting the potential to divide low-income customers from other customers and, as well, a concern with the income means testing that would be required.

MIPUG

DSM Programs

MIPUG suggested MH pursue all DSM opportunities where the projected costs to secure energy savings are at or below the marginal cost of new generation.

MIPUG advised MH not to screen out DSM opportunities on the basis of customer economics, but instead focus on ensuring customers have sufficient information to conduct their own evaluation of the costs and benefits of the DSM opportunity. MIPUG suggested MH's current approach may be screening out beneficial DSM measures.

DSM Program Evaluation

MIPUG expressed concern that MH's present approach is screening out economically justifiable opportunities, and opined that the TRC test excessively focuses on participant economics, and that it is possible that DSM activities that would be economically beneficial to MH and its customers are being screened out under the TRC test because the economics were not sufficiently advantageous to the participant.

Low-income programs

MIPUG opined that affordability programs to benefit low-income customers represent social policy considerations that more properly lie within the mandate of the provincial government. To base rates on a customer's ability to pay is, for MIPUG, discriminatory. Similarly, operation of a DSM program targeted solely at low-income customers is considered by MIPUG to be discriminatory, with MIPUG focused on MH's obligation to provide power to all its customers.

MIPUG opined that precedent suggests that decisions undertaken that exceed or define the bounds of discrimination should be made by explicit direction by the legislature and should not be undertaken in the absence of such direction. MIPUG's cited past legislation related to uniform rates and the establishment of the AEF, both created through government initiated legislative changes.

MIPUG further stated that if any approaches are to be undertaken to benefit low-income customers, they should be revenue neutral to non- low income customers

MKO

DSM Program Evaluation

MKO submitted that DSM programs should not be required to be revenue neutral for any particular customer class, or group of customers.

For MKO, to the extent that a provincial government elects to use MH rates as a social policy implementation tool, and provides clear direction to MH to do so, then the variance from standard rate design principles is justified.

MKO further stated for DSM programs targeted to benefit certain customers, that in the absence of a clear provincial government direction on “who should pay”, MKO submits that all MH customers should bear the costs.

Diesel Community DSM Programming

MKO submitted that energy efficiency measures are very important, especially for high-cost diesel served communities. In measuring energy savings in the diesel zone, 1 kW.h saved also reduces the cost of diesel fuel to generate the kW.h. However, since a kW.h saved in the diesel zone does not provide an extra kW.h for export sale, the more traditional approach of valuing a kW.h saved with respect to delaying new generation capacity or adding to export sales should not be used with respect to the diesel zone.

MKO noted that MH has suggested that through population growth the electricity required to serve the diesel communities may double over the next 20 years. MKO noted its understanding that INAC will pay for new generation capacity only for the diesel communities, whereas all MH customers pay for new generation capacity for the rest of the province. MKO is concerned that since MH does not have to pay for new generation capacity in the diesel communities (with the costs largely being met by INAC and rates), the Corporation has not pursued energy efficiency programs in the remote communities to the extent that it should.

MKO indicated concern with MH’s statement that its home audit program would not apply to homes in MKO communities, where, for MKO, MH perceives the benefits flow to INAC. Accordingly, MKO recommended that the Board immediately direct MH implement DSM programs for all customers in all MKO First Nation communities, whether or not MH perceives that benefits may accrue to INAC. MKO further recommended that MH personnel working with MKO First Nations customers be directed to meet with MKO First Nations to resolve misconceptions regarding the beneficiaries of DSM programs in the MKO First Nations communities.

MKO submitted that MH has been operating in violation of the spirit of Board Order 17/04, where MH was directed to implement DSM and energy efficiency programs in the diesel communities as part of the effort to reduce the financial burden on MKO customers. MKO further submitted that MH should re-evaluate its energy efficiency programs and incorporate Mr. Dunsky's recommendations to revise qualification criteria and set more realistic targets for the amounts MH will invest in energy efficiency measures in the diesel communities.

RCM/TREE

DSM Programs

RCM/TREE stated the principles of sustainability and justice should guide the Board in its determination of the public interest.

RCM/TREE noted that despite MH's internal assessment of success in its DSM program efforts, MH's standard electric residential customers continue to increase their energy consumption while Saskatchewan Power customers reduce their consumption.

While RCM/TREE supported MH in its bid to be both financially secure and socially responsible, the intervener suggested MH should further develop DSM and bill affordability programs for low-income customers.

Mr. Paul Chernick, a witness engaged by RCM/TREE, suggested that MH should double or triple its energy-efficiency spending, and energy savings, from current levels. Mr. Chernick stated that increased energy savings over the next few years would help to offset the expected and/or risk of energy shortages that may lie ahead, and that while MH asserts that “the only option available for 2009 is imported power” (to meet a possible energy shortage), accelerated DSM is clearly a lower-cost option.

For Mr. Chernick, increased energy savings over the next decade would increase MH’s flexibility, allowing it to avoid the anticipated 2020/21 energy deficit (before both Conawapa and Keeyask are expected to be on stream), without having to extend the operation of the thermal plants, while allowing the Utility to commit to larger and longer-term firm export sales.

Mr. Chernick advised that if the Board were to increase MH’s funding for DSM, low-income programs, economic development, or to strengthen MH’s balance sheet, the additional charges should come in the form of higher energy rates rather than increased demand charges, and by way of inverted higher tail-block energy charges.

DSM Program Evaluation

Mr. Chernick recommended the RIM test be discarded as a guide to the selection of DSM programs, and suggested that there are better ways to evaluate DSM programs. As to the evaluation of DSM programs, Mr. Chernick suggested the Board embed a value for carbon even though a carbon tax is currently not being received through current export prices.

Mr. Chernick recommended the Board direct MH to incorporate in its planning environmental costs for which it is not now being paid by export customers, and report back to the Board on the feasibility of including the additional benefits to Manitoba and the global environment from the reduction of carbon emissions, and how these benefits might best be incorporated in rate design and DSM evaluation.

Low-Income Programs

RCM/TREE submitted that MH should institute an affordability program, as recommended by Mr. Steven Weiss, a witness engaged by the intervener. For RCM/TREE, in addition to the social benefits that would come from a bill affordability program for the least well-off in society, such programs are also beneficial to non-participating customers because of reductions in utility collection and administration costs and reduced bad debts of low-income customers.

Mr. Weiss stated to make energy affordable, it is important for the Corporation to focus on customer energy burdens and target for benefits the most vulnerable, the benefits to be DSM and direct bill assistance. He defined energy burden as the percentage of income that non-transportation energy costs represent of household income. Mr. Weiss described a high-energy burden to represent 11% or more of household income, with a severe energy burden defined as being 15% or more of a household's income paid for energy.

Mr. Weiss recommended MH measure energy affordability, gather information on the energy burden of Manitobans, and track the effectiveness of its programs in reducing the number of customers with high and severe energy burdens. Mr. Weiss recommended MH should aim to reduce low-income residential consumers' energy burden to, at minimum, levels below the severe burden level of 15% of household income. He also suggested that over time MH should amend its goal, and seek to reduce the maximum energy burden to 11% of household income.

Mr. Weiss stated specific plans should be set to target the Low income households with the highest usage, and these residences should be provided conservation measures and bill assistance. Mr. Weiss also suggested MH should set goals and outreach targets for seniors, minorities, the disabled and families with young children.

Mr. Weiss noted that the bill assistance programs of other jurisdictions take many forms, including one-time crisis assistance payments (in the $200 - 300/year range), arranging forgiveness, rate discounts, monthly credits and assistance based on maximum percentage of household income..

Mr. Weiss indicated that programs considering the percentage of income required to be devoted to energy bills work best, when assistance levels can be set according to income level. He provided an example, whereby a customer would be charged no more than 9-10% of his/her income, being deemed a level that is “affordable.” In Mr. Weiss’ example, any bill amount over that level would be met through the bill assistance program.

Mr. Weiss stated that the customers of utilities offering such programs are often required to make timely payments in order to remain with the program; the goal being to provide an incentive for customers to stay current within a budget they can afford. Mr. Weiss further stated that these programs have proven to be extremely successful in reducing disconnection, arrearages and write-offs. He also recommended that such measures work best with equal payment plans.

Mr. Weiss’ final recommendation was that a bill affordability program could begin as an experiment, and involve the use of a control group of low-income customers not enrolled in the program. He suggested that frequent evaluations of bill assistance programs and pilots are very useful, and that an advisory group consisting of social service agencies, low-income customers, conservation and social justice advocates, as well as utility personnel involved with the program would prove useful.

In addition, RCM/TREE expressed support for the proposals put forward by Mr. Dunsky, the witness for the Coalition who proposed recommendations to remove barriers to low- income program access.

In addressing the question of whether the Board has the jurisdiction to implement low-income programs, RCM/TREE referred to a recent decision of the Ontario Supreme Court of Justice Divisional Court (dated May 16, 2008) involving the *Advocacy Centre for Tenants* and others versus the *Ontario Energy Board* (OEB). In the Court's decision, Justices Kiteley and Cumming dealt with the issue of whether low-income programs could be viewed as being within the OEB Board's jurisdiction.

In that decision, the Court held:

> "However, in our view, the Board need not stop there. Rather, the Board, in the consideration of its statutory objectives, might consider it appropriate to use a specific method or technique in the implementation of its basic cost of service calculation to arrive at a final fixing of rates that are considered just and reasonable rates."

RCM/TREE interpreted the finding to mean the Board's jurisdiction could extend, to include the objective of energy conservation, and, as well, to the use of incentive rates or differential pricing, to further the objective of protecting the interests of consumers. RCM/TREE further interpreted the decision to suggest the Board may take into account income levels in setting utility rates, to achieve the delivery of affordable energy to low-income consumers (on the basis that this would meet the objective of protecting the interests of consumers with respect to prices).

RCM/TREE submitted the Board is engaged in rate setting within the context of the interpretation of its statute (*The Public Utilities Board Act*) in a fair, large, and liberal manner and that is not engaged in setting broad social policy; accordingly RCM/TREE urged the Board consider the approaches it recommended.

11.10 Board Findings

DSM Programs

The Board recognizes that MH has been making an increasingly significant investment in DSM programs, and has gone beyond the efforts made by the vast majority of other utilities, with spending increasing in recent years from $11.9 million in 2003/04 to a forecast in the order of $43.1 million for fiscal 2008/09.

MH's program now has a low-income component and it is a segment of MH's integrated resource plan, as energy savings allow for additional energy to either be sold on the export market or allow for the deferral of expensive new generation. Both outcomes can have the effect of improving MH's financial position and dampening the need for sizeable future rate increases.

The Board encourages MH to continue to pursue environmental objectives on an integrated natural gas-electricity basis, and in particular, to consider the position of low-income customers increasingly faced with higher energy costs and too often lacking the funds and know-how to achieve needed upgrades that would reduce their energy bills and GHG emissions.

For the Board, the Utility's DSM focus should be four-fold:

a) environmental – the reduction of wasted energy through reduced GHG emissions (here and in MH's export markets – climate change is a global challenge, the wind blows north as well as east, south and west);

b) economic – energy not consumed by Manitobans should be available for sale on the export markets, and as much of that as possible during on-peak hours at peak prices – exports are taken into account in determining domestic rates without exports current rates would be, on average, 15% higher;

c) economic – energy not consumed by Manitobans and not sold on the export market, either due to transmission capacity or price issues, can assist in the deferral of new generation and transmission, saving capital dollars and attendant interest and depreciation (construction and commodity costs have recently soared, driven in part by extraordinary expansions – of oil sands production in Alberta and the energy demand of China and India; sometimes delays can allow for projects to take place in times of more stable prices); and

d) social – increasing the energy efficiency of low-income households will allow more families to remain in their homes and to have more disposable income available for necessities other than energy (the total cost of energy – gasoline, natural gas, electricity, propane, etc., has soared for all households, but the cost increases have been particularly devastating for households in the bottom four deciles of household income levels).

With respect to the approach the Utility now takes to accounting for DSM costs, as it has in past orders the Board continues to question the appropriateness of deferring DSM costs, an approach that is now challenged not only by the Board's concern but also by the upcoming IFRS. The Board has had and remains of the view that DSM costs should either be expensed in the period incurred or amortized consistent with the much shorter periods of amortization followed by other jurisdictions.

MH defers DSM expenditures for subsequent amortization over 15 years, whereas Hydro Quebec and BC Hydro, (sister crown utilities) defer less DSM and amortize deferred DSM expenditures over a much shorter time frame. In the case of BC Hydro, DSM costs are amortized over the short term of the useful life of the program or a maximum of 10 years. Hydro Quebec also amortizes DSM expenditures over a 10-year period. With the coming introduction of IFRS, the current amortization policy will be reviewed and a more conservative approach may be an option for early adoption.

Amortization of DSM spending is forecast to grow from $9 million in fiscal 2007 to over $13.7 million in fiscal 2009, while actual spending on DSM initiatives is forecast in 2007 at $36.1 million, and to grow to over $43 million in fiscal 2009. Thus, MH now plans for deferred DSM to grow to over $180.9 million by March 31, 2009, a balance expected to continue to grow significantly through to 2018, due to increasing annual DSM spending which will eventually have to be recovered in rates – now to be achieved over a period too long for the Board.

The Board recommends MH consider changing its accounting approach to one that provides for the amortization of DSM costs over a period no longer than five years.

DSM Program Evaluation

The Board notes that MH projects that by fiscal 2017/18 (and speaking now as to electricity operations) it will have achieved 2,637 GW.h of DSM savings (1,706 GW.h through incentive-based programs and 931 GW.h of savings through changes to Codes and Standards, etc.). If achieved, this would represent a 240% increase in DSM savings over 12 years, a growth rate of almost 20% per year. (Demand savings are expected to reach 842 MW, an increase by 170% over 12 years, or almost 15% per year.).

While the projections are impressive, the Board suspects the opportunity for further reductions is great. As well, the projections are also highly subjective. MH relies on forecasts which can only be partially verified.

Despite major increases in DSM expenditures over the last four years, DSM has not had a marked effect on the deferral of planned generation and transmission projects. Since inception, DSM has, at best, offset 20% of domestic load growth. The Board notes that MH is forecasting the risk of energy shortfalls (demand, domestic and committed exports, as compared to local hydro-electric supply) through to the in-service dates of future generating stations Keeyask and Conawapa. If shortfalls do occur, and past experience and probabilities suggest a high risk of drought or below median water conditions occurring within the next five to ten years, then, as matters now stand, MH will have to rely on imported power from the MISO market. MH’s MISO-market partner utilities generally use natural gas for peak demands, so the cost of imports can be a multiple of the average price of MH’s exports.

In such a condition, and if a drought were to be sustained for five years (which has occurred in the past), MH has advised the Board that it could “run” a loss of over $3 billion, an amount that dwarfs the Corporation’s current retained earnings balance and which would have implications for rates and the general view of the Corporation’s fiscal stability going into a period of expected significant expansion.

For the Board, the risks inherent to a Corporation depending in the end on the weather suggest that there should be an even more increased focus on conservation and DSM, so as to further reduce demand to provide an increased buffer between Manitoba hydro-electric supply and likely demand in the future. Such increased DSM initiatives may also address the currently-forecast future expected shortfalls.

Energy conservation has never been of such importance to MH as it is now, as it contemplates a massive capital expenditure program, to produce power that now is expected to be required to meet rising domestic load and continuing committed export markets.

Now, as previously indicated, MH does not expect the conversion of current natural gas space heating load to electricity, nor does it expect an abandonment of natural gas as the space heating choice for new residential construction. Given the Board's understanding of current and forecast natural gas prices, and its expectation for even higher domestic load growth due to such new phenomena as "electric" and "hybrid" cars, relying on electricity rather than gasoline, the Board urges MH to focus on conservation and upgrade and develop new DSM programs, to free up hydro-electric generation to meet the risk of much higher domestic load growth than the Corporation now forecasts.

This will likely require an expansion of existing as well as additional DSM programs, along with taking more into consideration societal impacts in the evaluation of DSM programming. In short, the Board recommends that MH "step-up" its DSM plans and targets.

Indirect GHG Reductions

Interveners have suggested that increased export sales achieved by diverting price restrained domestic load growth to MISO will achieve global GHG reductions comparable to displacing coal-fired generation.

MH's evidence was that the GHG reductions are, to a greater degree, reflective of natural gas generation displacement, since the carbon footprint for natural gas generation is less than 50% of that for coal generation.

The Board sees a need for more clearly defining the relative environmental benefits of exports, and will direct MH to provide a detailed analysis and report to the Board before June 30, 2009 as to whether there are greater global environmental (GHG) and economic benefits by exporting hydraulically-generated electricity than would be achieved by fuel switching (from natural gas to electricity) and/or geothermal within Manitoba. The report should address and clearly define the relative environmental and economic benefits of exports. The assumptions should also be included in the report. Currently, Manitoba consumers and businesses transfer $1 billion to the gas producing provinces and states that supply Manitoba's natural gas, and these costs and transfers of funds to outside the province may soar even higher in the future.

Low-Income Energy Efficiency Programs

With respect to low-income programs, the Board commends MH for recently beginning to address the energy conservation needs of low-income households.

The Board is also encouraged that MH plans to enhance its low-income programs and target rental premises as well as owner-occupied residences, with MH's commitment to extend the low-income program to tenants of apartments. The Board further understands that there may be resistance for landlords to take part in the program due to split incentives and low-cost business models that some landlords may choose to operate under.

The Board also urges MH to make efforts to incent landlords to participate in the program to improve the energy efficiency of their properties, to the benefit of their tenants and the environment. The Board will expect MH to consult with stakeholders on its enhancements to its low-income programs to ensure it adequately addresses low-income needs, and to report to the Board by September 30, 2008 on the results of the consultation and subsequent development and implementation of this program.

Although MH is beginning to address the issue of energy poverty, more is required. The Board is very concerned with the slow pace of the overall effort. The Board notes that MH's current program is anticipated to address only 4,600 lower-income households over the next three and a half years, while the current low-income population is likely at least in the order of 100,000 households – and that is before taking into account recent major inflationary increases in general energy costs and risks of a slowing economy and higher unemployment.

Based on the current pace of MH's low-income DSM programs, the Corporation's spending over the next three years on low-income programs will not put a dent in the problem, and, at best, address only a very small fraction of low-income households. At the proposed pace of the program, it would take decades to obtain a significant level of participation of low-income households in MH's energy efficiency programs.

Low participation acts as a barrier to the lowering of excess energy bills and GHG emissions, and the putting in place of meaningful inverted rate program designs for residential customers. The Board agrees with the views expressed by the Coalition and RCM/TREE that more should be done in this area, to accelerate its efforts with respect to reducing the energy burden of low-income households.

The Board will direct MH to file with the Board on or before June 30, 2009 a draft plan, with projected implications, to increase the Corporation's integrated (natural gas and electricity) energy efficiency initiatives with respect to low-income households, so as to allow for reduced energy consumption for all such households within a decade.

The Board notes the evidence of Mr. Dunsky who critiqued MH's design of its low-income programs. Mr. Dunsky's suggested changes to MH's program were designed to overcome the barriers of program participation, barriers that clearly remain a significant concern of the Board. The suggested changes put forward by Mr. Dunsky have merit and should be considered by MH in its design of current and new low-income programs. The Board notes a willingness by MH to consider many of Mr. Dunsky's recommendations, and urges MH to not only consider the recommendations, but to internalize many of them, and take full ownership as to the delivery of the programs.

The Board was intrigued by the refrigerator replacement program proposed by Mr. Dunsky, and will direct MH to report back to the Board on a low-income and a general refrigerator replacement program, and provide the merits of such programs, on or before June 30, 2009. And, with respect to MH's new natural gas furnace replacement program (launched following Board direction that arose out of a Centra GRA), the Board appreciates the evaluation provided by Mr. Dunsky, and takes note of Mr. Dunsky's suggested changes to the program, including his suggestion for a lease program, with the lease payment linked to the energy benefit.

The Board notes Mr. Dunsky's critique that, as designed, the furnace replacement program will not prove an adequate incentive for the early replacement of inefficient natural gas furnaces and, at best, will likely only marginally assist the natural replacement market. The Board urges MH to seriously consider program changes to increase participation in early replacement of inefficient furnaces. Changes to the program that will better provide this opportunity are well worth the effort, and should provide energy savings for low-income customers and significant non-energy benefits to society, the Utility and the participants in the program.

The Board is aware that MH only recently launched its furnace replacement program, and suggests that design changes may be fairly easy to introduce at this time. MH has an opportunity to put this program on the “right footing” in advance of the upcoming heating season – when natural gas bills for all customers, not only low-income, may be considerably higher than they were in the previous winter.

The Board is interested in the take up of the program, and understands that it has been very low to-date, and will require MH to provide an update on the status of the current natural gas furnace replacement program (including actual and forecast take-up rates), as well as reports of possible changes to the program relative to the suggestions put forward by Mr. Dunsky, on or before September 30, 2008.

While not as aggressive, perhaps, as the Board’s recommendation that low-income customers be allowed subsidized Power Smart Loans and payment schedules involving an option requiring payment only upon the sale of the residence, Mr. Dunsky’s lease concept has merit as an option. Whether MH proceeds to adopt the Board’s recommendation for a subsidized loan program secured by the residence, or follows up and introduces a furnace lease program as suggested by Mr. Dunsky, either approach appears to be more likely of achieving success than the current approach being followed by the Corporation.

Installing high-efficiency furnaces in residences now relying on furnaces that may have efficiency ratings as low as 40% or below should assist in restraining the conversion from space heating by natural gas to electricity, that would, if it occurred, only intensify MH's supply/demand situation in the years to come.

With respect to the AEF, MH has taken the position that interest should not accrue on AEF balance, this contrary to that directed by the Board in Order 99/07. If interest was accrued on outstanding AEF balances, the AEF would have additional revenues available to fund further low-income programs. The Board recognizes that capacity issues may exist in program delivery; however, the Board believes that if more funds were made available, such programs could be expanded to meet more of the needs. If interest is not allowed to accrue to the AEF, its purchasing power will decline by at least the rate of CPI inflation; accruing interest will remove any disincentive to move quickly to put the AEF to work.

The Board does not agree with MH's perspective of the intent of the legislation that gave rise to the AEF. The Board will require MH to accrue interest on the AEF balance to ensure additional funds are available to fund expanded low-income energy efficiency programs.

The Board is also particularly concerned with the delivery of low-income programs on First Nations diesel communities. The Board notes MKO's concern that energy audits and low-income programs may not be available to diesel community households, with the perception that the benefits will be realized by INAC. The Board expects MH to meet with MKO and representatives from the diesel communities to discuss the issue of the access of those communities to MH's low-income programs, and to report to the Board on the outcome of these discussions on or before September 30, 2008.

The Board is very concerned with the burden low-income households face with higher energy costs, even more so given the rapid increases in both oil costs and natural gas pricing. The Board believes that MH has a duty to ensure a safe and reliable service to its customers. The question is whether that duty should extend to ensuring electricity is made available on an affordable basis.

Bill Assistance

The Board notes that the low-income high energy burden problem is extensive in Manitoba and that MH now relies on a voluntary program, Neighbours Helping Neighbours (Salvation Army), which allows MH customers to donate to a fund, a fund the Board finds sorely inadequate. Families and seniors who are unable to pay their natural gas or electricity bill due to personal hardship or crisis can receive support from the program, but only if sufficient funds are available.

While a voluntary program is beneficial, it cannot meet the need in the Province as it is now established. A low-income bill assistance program would assist in reducing the energy burden faced by low-income households. Significant non-energy benefits would arise, including increased comfort, reduced health costs, lower bad debt write-offs etc. .

Manitoba is a cold environment from the fall through to the spring; in this Province, adequate heat is a necessity of life. In light of this reality, the Board recommends government seek from the Federal government an exemption from GST for residential customers, as heat in Manitoba is a necessity like food; and to fund low-income and DSM programs, the Province should set aside all or a portion of provincially and or municipally sanctioned sales taxes charged to residential customers on energy used for heating purposes.

The Board notes that MH's commercial customers may recover GST paid on input costs and that health and educational institutions also receive favourable treatment with respect to the GST.

In a 2007 proceeding before the Ontario Energy Board (OEB) the Low-income Energy Network (LIEN) sought approval of a rate affordability assistance program to make natural gas distribution rates affordable to poor people. The underlying premise of LIEN's position was that low-income consumers [estimated at approximately 18% of Ontario households] should pay less for gas distribution service than other customers. The issue LIEN sought to advance were:

- Should the utility's rates include a rate affordability assistance program for low income consumers?
- If so, how should such a program be funded?
- How should eligibility criteria be determined?
- How should levels of assistance be determined?

In a split decision, the majority of the OEB panel concluded it did not have jurisdiction, pursuant to its existing legislation, to order the implementation of a low-income affordability program. The majority of the OEB concluded LIEN'S proposal amounted to an income redistribution scheme requiring one consumer rate class based on income characteristics as well as implicitly require subsidization of this new class by other rate classes.

LIEN appealed the OEB decision to the courts. Also by a split decision, the Ontario Superior Court of Justice, Divisional Court recently allowed the LIEN appeal and declared that the OEB has the jurisdiction to establish a rate affordability program for low-income consumers of the utility.

Because both the Manitoba and Ontario rate setting jurisdictions are similarly broad, this Board has previously indicated its concurrence with a dissenting position of the OEB on its ability to establish a rate affordability program for low-income utility customers, a position since upheld by the Court.

Energy affordability for low-income families is very much an issue that requires more or less immediate attention in Manitoba. The Board suspects that low-income individuals, families and seniors, unable to pay their natural gas or electricity bills due to personal hardship or crisis, could receive support from a rate reduction program without causing a major rate increase for MH's other customers.

The Board believes that in light of the recent Ontario court ruling, it (the Board) would be acting within its mandate and in the public interest if it were to direct MH to implement a bill assistance program. Accordingly, the Board sees merit in the proposition put forward by Mr. Weiss. And, therefore, the Board will direct MH to propose for Board consideration (as soon as possible for the coming heating season, but no later than September 30, 2008) a low-income bill assistance program, where such a program would occur in conjunction to and compliment an expanded low-income DSM program.

MH should address the issues of: how such a rate affordability assistance program should be funded, how eligibility criteria should be determined and how levels of assistance should be determined. Consultation with the Coalition and RCM/TREE may be of assistance to MH.

The Board understands the issues and problems raised by the Coalition relative to similar programs available in the US, where access to funds is "real", thanks to U.S. federal government funding. The Board further believes a bill assistance program (as proposed by Mr. Wiess) should be extended along with a program to improve the heat retention and the efficiency of low-income homes, and the sooner the better.

12.0 Risk Analysis

The Board has, in past Orders, requested that MH to file a quantified Risk Analysis. To date, MH has submitted limited scope and/or generic discussions of issues that would better be incorporated in a fully integrated and quantified risk analysis that provides a detailed quantification of all substantial risks and a probability analysis to assist in the testing of the appropriate level of debt:equity ratio.

Over the years and at various GRA proceedings, MH has flagged numerous business risks to its financial well being, and stressed the need for adequate retained earnings in order to make progress towards its debt/equity target of 75:25. And, consistent with these views and in response to past Board Orders, MH submitted the following reports at this year's GRA:

a) Risk Advisory Report (January 18, 2005) (2004-04 Drought Risk Management Review);
b) MH's report on Risk Strategy and Quantification (January 31, 2005); and
c) MH's analysis of Financial Loss Due to Extended Periods (July 26, 2007).

The first of these reports was narrowly focussed on MH's response to the 2003/04 drought, particularly as related to hedging and energy buy-backs. The report did not deal with MH's operational strategies going into the drought, an issue the Board has a considerable interest in (now, as an indication of possible future risks). MH's second report addressed generic issues of risk management and how the Corporation defines overall business risks. Again, it neither provided detailed assessments nor quantifications of those risks.

In the third document filed, MH quantified the financial implications associated with a repeat of the three extreme drought events in recorded history. The events were presented as individual risks and not integrated in an overall quantified business risk assessment. Also, MH, in response to interrogation, provided forecast financial impacts for a variety of business risks. However, it remained MH's position that these risks should not be aggregated and that appropriate methodology does not exist to allow the incorporation of risk probabilities to produce an overall risk quantification.

The Board observes that Manitoba Public Insurance also faces a diverse list of risks for which an aggregation would not provide a fair impression of even likely worst case scenarios yet, its actuarial advisor has assigned probability, allocated provisions for adverse deviations, and produced an overall assessment.

12.1 Drought

The following tables identify the reduction in retained earnings as of March 31, 2018 that MH projects as being associated with various unfavourable events (as identified during the hearing).

Drought Risks ($ millions)

Event in Forecast Period	Frequency	Retained Earnings Reduction	Retained Earnings, March 31, 2018
IFF 07-1	0	0	$3,349
One Year Drought (50% of 2003/04 Loss)	1 in 10	$ 490	$2,859
2003/04 Drought	1 in 15	$ 891	$2,458
Five-Year Drought (as per 1987-91)	1 in 50	$2,800	$ 549
Seven-Year Drought (as per 1936-42)	1 in 100	$3,500	($ 151)

A review of 94 years of river flow history revealed that MH has faced drought situations in 23 of the 94 years (1 year of each 4). Consecutive years of drought occurred in the periods 1929 to 1932, 1936 to 1942, 1976 to 1977, 1980 to 1981, and 1987 to 1991. MH has recognized the compounding effect on retained earnings of a multi-year drought and defined the financial consequence of a five-year drought modelled on the 1987 to 1991 experience, and, as well, the consequence of a seven-year drought modelled on the experience of 1936 to 1942.

These forecasts are presented as if these events had happened during the forecast period, to 2017/18. (The 2003-04 drought may well have been the most severe single-year drought in MH's flow history.)

The modeled multi-year droughts were projected to have retained earnings impacts of $2.8 billion for a five-year drought, and $3.5 billion for a seven-year drought. MH has never identified a "dollar based" retained earnings target, but relies on a 75:25 debt:equity target.

For a seven-year drought projected as above, and given an initial retained earning of $1.7 billion, MH forecast that an additional 4.0% annual rate increase, on top of the currently projected annual increase of 2.9%, applied over a 10-year period would not only restore the $1.7 billion projected to be lost as a result of the drought but would provide for a doubling of retained earnings to $3.5 billion by March 31, 2018.

This may suggest that $1.7 billion could be considered an adequate reserve for a seven-year drought, and that a 2% to 2.5% additional and annual rate increase for the ten years following such a drought would restore the initial reserve. However, assuming MH's current capital expenditure forecast is realized, restoring the $1.7 billion of retained earnings through annual 4.9-5.4% rate increases would not achieve a 75:25 debt:equity ratio; in fact, the retained earnings deficiency in such a situation would be quite significant.

The 2003-04 drought demonstrated that MH's generally "aggressive" approach to export energy marketing, while conducive to higher profits in median or above flow scenarios, carries the risk of increased losses during drought or low flow years. MH has acknowledged this risk, but believes its present strategy (that is, depending on median water flows) provides greater longer-term financial returns. The Board is not so certain and would prefer an independent assessment be conducted and filed.

Some of MH's exports involve three to four month advance sales of firm energy, without the certainty that the firm energy sold will be available (i.e., precipitation may not replenish water resources). Such practices lead to reasonable results in the absence of poor water conditions, but significant cost consequences when water flows fall and imports have to be purchased to fulfill contract obligations. This situation occurred in the summer of 2006/07 and, in the Board's view, contributed to MH's request for a 2.25% interim rate increase (granted initially as an interim increase and finalized by Order 90/08).

The drought scenarios represent events that could all occur over a 100-year period. However, the Board considers it reasonable that there is a very low probability that more than one multi-year drought would occur in a 50-year time period, let alone more than one during a 10-year forecast period. As such, the forecasts of multiple drought situations are not reasonably additive.

MH cannot prevent droughts from occurring, but, arguably, could do more than was done in 2003/04 to mitigate the consequences of a multi-year drought. In 2003/04, energy from water held in reserves was sold at low prices (off-peak pricing) to boost that year's annual income, only for the energy to be required to be "bought back" from the MISO market to meet MH's export commitments, and then at much higher prices than what the energy was sold for.

12.2 Other Risks

The "other risks" displayed in the following table are also circumstances that MH cannot control. However, as with droughts, the cost consequences of each can be mitigated to some degree by MH actions:

Impact of other Risks ($ millions)

Event in Forecast Period	Frequency	Forecast Retained Earnings Reduction	Forecast Retained Earnings, March 31, 2018
Lower Average Hydraulic Generation for 10 Years (1,000 GW.h Less)	(1)	$500	$2,849
Lower Export Revenue Prices (6¢/kW.h for 10 Years)	(1)	$800	$2,549
Exchange Rate Remains @ Unity for 10 Years	(1)	$170	$3,179
7.5% Capital Cost Price Escalation Per Year	(1)	$872	$2,477
Loss of Bipole I & II (for 4 months in 2011/12)	(1)	$200(2)	$3,149
Higher Interest Rate (up 2% on Average)	(1)	$234	$3,115

(1) Each of the above "other risks" have potentially high probabilities, ranging from 1 year in 5, to 1 year in 50

(2) Does not include costs for infrastructure repair or replacement.

The risks shown in the above table are "all inclusive", and reflect scenarios that were raised in Board proceedings. As such, each is indicative of levels of risks that MH may be subject to at various times in the near future. From the Board's perspective, given the importance of MH to the Province and the capital expenditure plans that are now "on the table", a more exhaustive listing is still required, again with probabilities quantified.

The financial implications of these “other” risks may be considerably increased when MH’s recent export sales commitment announcements are confirmed in contract form. The nature of these sales and the additional capital costs associated with Conawapa and Keeyask generation and such additional transmission as may be required to meet the new commitments could substantially increase the magnitude of forecast reductions in retained earnings upon the occasion of an adverse event.

Not included in the above table are variations in domestic energy demand, medium-high domestic load scenarios as a result of extremely cold winters that can lead to energy shortages which would have to be offset by high priced imports, or conversions of energy sources to electricity from natural gas and propane. On the other hand, low-medium domestic load scenarios that arise with very mild winters can lead to energy surpluses, which in high flow years may have very limited market value.

Domestic residential and small commercial load growth comes with average revenue rates that have been above those achieved by average export rates. Domestic load growth in the large industry sector obtains the lowest rates offered by MH, other than those obtained from export sales during off-peak hours.

Overall, adverse events have variable probabilities. Two or three of these additional risks could occur in the same time period and, as such, their impacts on retained earnings could be additive. However, it appears that the total impact of the “other risks” might be of a lesser magnitude than what would be occasioned under severe drought situations.

12.3 Interveners' Positions

MIPUG, Coalition, and RCM/TREE all questioned the need for a retained earnings level based on a ratio of debt to equity, but, excepting for MIPUG's concept of specific reserves, have not made specific recommendations. A specific Board initiated review and quantification of risks has been recommended and the Coalition continues to support improved equity levels and suggests that further testing of retained earnings and reserves targets are required.

MIPUG proposes that the Board convene a special hearing to deal with risk and reserve issues, and that the Board should provide MH with prescriptive requirements and scope to define what would represent an acceptable comprehensive risk analysis and adopt an appropriate reserve mechanism for testing at future proceedings.

MKO also supports a broader role for the Board in defining business risks, including those associated with major capital programs.

12.4 Board Findings

Drought

Over the past decade or so, extra-provincial revenues have represented a significant portion of MH's actual and forecast revenues. And, as demonstrated by the $428 million loss in 2004, MH honours its obligation to meet firm export commitments by purchasing high price power in the event of a drought. The drought made clear the significant dependence that MH has on water flows; reasonable water conditions are clearly a requirement for MH to obtain favourable net export revenues and sustain domestic rates at below-cost levels.

As such, MH's energy supply resources and export commitments require constant monitoring, particularly as its assets and debts are to increase with planned massive capital expenditures.

MH has suggested that the drought of 2003/04 can be expected to re-occur once every 15 years, on average. Yet, longer droughts of greater consequence have occurred at least three times in MH's relatively short history. While MH has defined the potential impacts of various drought events, it has not provided a frequency-based in-depth analysis that is required to demonstrate the full range of economic consequence of the risk. MH will be directed to provide such an analysis.

In low water years, when MH experiences an energy shortfall, the available sources of "make-up" energy in the MISO market tend to be less efficient and very high cost natural gas generation (like the Brandon SCCT units, which recently had output costs of about 15¢/kW.h – compared to 6 cent rates for residential customers and 3.2 cents for large industry). Consequently, when MH operates gas generation to meet its export commitments, it is fulfilling export contract commitments at a substantial loss.

Unfortunately, in high flow years, MH's surplus (can be up to 7,000 GW.h greater than average) may only attract off-peak prices (and these have been under 2¢/kW.h during the summer months), as peak and shoulder-hours generation sales are limited due to transmission capacity and MISO needs. The difference between the price of a sale during peak hours and one during off-peak hours can be very significant, the former sometimes 10 times the latter, and with the latter usually being so low as to give rise to the question as to whether the sale was of strategic value.

This indicates a fairly large market risk related to MH's marketing strategies. To monitor these, the Board will be requiring MH to provide the Board with specific quarterly reports on energy supplies (including imports), domestic demand, and export sales (e.g., similar to NEB volume and price data). Alternatively, the Board could rely on annual reports, but they would enable only a form of post-mortem analyses and provide no opportunity for the Board to offer comment on more current strategies and their possible implications for consumer rates.

Infrastructure

Given the risks that abound with massive operations of high importance to not only utility customers but the Province overall, the Board will direct MH to provide regular due-diligence reports on its infrastructure, focusing on the risk aspects of the operation (e.g., Dam Safety Reports, Maintenance, and Rehabilitation Schedules, etc.), as part of expected regular updates to an Asset Evaluation Study.

Load Growth

The Board acknowledges MH's concerns about domestic load growth, particularly in the industrial sector. MH should provide a more detailed tracking of industrial load growth, along with a range of reasonable projections for the future when it re-files its application for a new industrial rate category in the fall..

The Board understands that MH's increasing DSM program is expected to offset a significant portion of domestic load growth. As such, it is essential that MH reconcile forecast DSM savings with its load forecasts and actual domestic loads. This type of analysis should be incorporated in Future Load Forecasts.

MH has yet to take a position on what might be likely climate change impacts on hydraulic generation, yet it assumes the global warming scenario in defining its export price forecasts and DSM benefits. The Board wants to explore the risks and opportunities that may lie with climate change at the next GRA, and trusts that MH is involved presently with such studies and is considering various possible scenarios, given recent new export commitments and plans for additional investments in generation and transmission facilities.

Capital Cost Escalation

The ambitious major capital program which has been undertaken to meet future export commitments and domestic load growth is expected to result in the spending of approximately $18 billion on major projects, including Bipole III, Keeyask and Conawapa. The Board notes that hyper-inflation and labour shortages was cited by MH as major reasons for the escalation in the costs to construct Wuskwatim, which is currently under development. In its evidence, MH did not indicate that the price increases experienced to date represented a short-term trend.

The Board is concerned that this higher-cost trend may continue. The Board questions and is concerned whether current forecasts of major capital programs are fully reflected in the forecast before the Board, and is concerned with the risk that an updated capital forecast more reflective of recent inflationary experience related to capital projects may show substantially-higher capital requirements, putting upward pressure on future rates.

The Board needs to examine a variety of cost and price scenarios to better assure it that the planned new capital projects will not require significant domestic rate increases over the longer term. The Board has directed MH to file an updated Power Resource Plan and provide an analysis of the rate impacts of the new planned capital projects.

Export Commitments

While the Board has not been provided with MH's specific export contract prices and terms, it is concerned because of recent average export price history. MH's forecasts assume an USD/CDN exchange rate of 1.16 and CO_2 legislation to achieve average export prices of 10¢/kW.h by 2018. If that expected price in Canadian currency does not materialize, MH could be faced with an extended period of time where average export prices will not cover incremental costs associated with Bipole III, Keeyask G.S., and Conawapa G.S, just as happened after the Limestone G.S. in-service of 1992, and as expected for several years following Wuskwatim coming into service.

With construction costs in a higher inflation mode and with interest rates at recent historic lows, it is impossible to be certain prices that have been secured on the export market will prove adequate. A relatively modest worst-case scenario could involve a 1-2¢/kW.h shortfall on export sales extending well beyond 2025. And, with Bipole III routed on the West Side of the Province, costs to be allocated under the COSS model may be 0.5¢/kW.h more than if Bipole III was to be on the East Side of the Province. A shortfall from required export pricing could have the effect of reducing future annual net income significantly after 2018, placing further pressure on domestic rates.

Other Risks

With inflation increasing and transportation costs soaring, it is difficult to imagine interest rates being sustained at current historically low levels. And, with oil at $140 a barrel and some industry observers predicting the price reaching $200, it would appear less than conservative to assume that the Canadian dollar is going to depreciate significantly from its current "near parity" level. Both an increase in interest rates and, perhaps, even a further appreciation of the Canadian dollar would have significant implications on the operations and results of MH, implications not yet quantified.

In light of the many risks discussed, the Board has directed MH to prepare a Risk Analysis to fully quantify the financial impact of the risks faced by MH.

13.0 Cost of Service

13.1 Background

Currently, MH's Cost of Service Study is a prospective study of average (embedded) historically-based costs classified, functionalized, and allocated to each customer class and sub-class on the basis of system usage. The costs reflect invested funds in Generation, Transmission, and Distribution, updated to use in forecasting costs for the next upcoming fiscal year.

Costs related to finance (interest, etc.), depreciation, and OM&A are shared by domestic customer classes and one export class on the basis of energy consumption, peak load demand, and customer numbers. Currently, surplus export revenues (above assigned and allocated costs, i.e. notional profit) are credited to the various domestic classes proportional to their share of total allocated costs.

COSS is a tool to assess the extent to which each customer class' revenues recover/compare to allocated and historic costs. The revenue to cost coverages derived from PCOSS-08 illustrate a degree of disparity in embedded cost sharing by the various classes. Yet, the results should not be viewed as being representative of a degree of unfairness, but rather as an indication of possible rate increase differentiations, if only historic costs are to be taken into account and the current method of allocating costs and revenue (including net export results) is maintained.

MH employs a Zone of Reasonableness (ZOR) from 95% to 105% to assess the need for differentiated rate increases. In this GRA, MH chose to seek an across-the-Board rate increase for all classes other than Area and Roadway Lighting (a class composed of municipal and other governments providing area roadway lighting to their communities).

MH opined that an across-the-board increase was justified, as no rate class is “paying” its full cost of service as long as MH has a retained earnings deficiency.

13.2 Amended PCOSS-06

In response to Order 117/06, which followed a comprehensive review of MH’s cost of service methodology, MH submitted a 16-page document that reflected most of the changes directed to be made by the Board in PCOSS-06 by Board Order 117/06.

Notably, the amended COS employed the following energy inputs:

Domestic Load at Generation	22,830 GW.h
Export Load at Generation	9,786 GW.h
Total Load at Generation	32,616 GW.h

For hydraulic generation cost sharing purposes, export load at generation was reduced by 9,786 GW.h, comprised of:

2,010 GW.h	(derived by imports)
587 GW.h	(derived by thermal)
1,117 GW.h	(DSM savings)
6,072 GW.h	(exports served hydraulic generation pool)

Revenues reported in the COS were:

Domestic:	$1,018.2 M (19,900 GW.h @ 5.12¢/kW.h at meter)
Export:	$547.4 M (8,800 GW.h @ 6.22¢/kW.h point of sale) - actual average export prices in 2005/06 were 5.2¢/kW.h.

MH carried out a 12-period weighting process of all hydraulic generation using the average Surplus Energy Program (SEP) pricing over an eight-year period. This approach was applied to actual domestic energy consumption and 2003/04 net export sales at generation. The use of a drought year for defining the 12-period export sales would have overstated the share of generation costs allocated to the export class (and accordingly, was not employed).

13.3 Export Costs

The COS directly assigned $123.8 million of costs and allocated a further $248.7 million of costs to the export class. These costs reflected:

	($ Millions)
Uniform Rate Adjustment	$16.7
DSM	$17.8
Trading Desk Costs	$9.1
MAPP/MISO/NEB costs; Purchased Power; and Thermal Costs	$80.2
Allocated Generation and Transmission (including Water Rentals)	$248.7

Revenue to Costs Coverage Ratios (RCC)

The revenue cost coverages for the amended COS were reported at:

Residential	94.1
GSS-ND	107.6
GSS-D	107.0
GSM	101.4
GSL<30	91.4
GSL 30/100	91.4
GSL>100	104.8
ARL	106.1

The Board did not formally respond to MH's filing of the Amended PCOSS-06, and requested the Corporation to employ the COS approach directed by Order 117/06 for the next GRA, the subject of this Order.

13.4 Embedded Cost Revenue Cost Coverages (RCCs)

In PCOSS-08, MH calculated the RCCs for the various customer classes as follows:

	After Net Export Credit	**Prior to Net Export Credit**	**MIPUG/MH I-25(b)**
Residential	96.4%	83.0%	95.9%
GSS-ND	104.3%	90.8%	103.9%
GSS-D	107.2%	93.8%	107.5%
GSM	101.1%	87.7%	101.3%
GSL <30	90.4%	76.9%	90.3%
GSL 30-100	103.7%	90.1%	104.6%
GSL >100	108.7%	94.8%	110.4%
AWR	105.8%	96.7%	105.6%

The foregoing PCOSS-08 RCC's (pre-2008 rate increase, 5% as per Order 90/08) continue to suggest a need for differentiated rate increases in the future. The results are relatively consistent with historical embedded cost RCC's, as shown in the following table:

Table: Historical RCC

	RCC PCOSS-08	**RCC PCOSS-06[1]**	**RCC PCOSS-04**	**RCC PCOSS-03**	**RCC PCOSS-02**	**RCC PCOSS-01**	**RCC PCOSS-99**	**RCC PCOSS-97**
Residential	96%	97%	91%	92%	97%	91%	92%	91%
GSS-ND	104%	107%	105%	107%	109%	104%	107%	107%
GSS-D	107%	105%	110%	108%	105%	105%	108%	105%
GSM	101%	101%	105%	103%	104%	109%	106%	102%
GSL 0-30 KV	90%	90%	100%	93%	97%	103%	101%	101%
GSL 30-100 KV	104%	102%	110%	109%	109%	119%	110%	108%
GSL >100 KV	109%	103%	114%	114%	100%	116%	109%	111%
A&R Lighting	106%	107%	109%	110%	102%	92%	93%	109%

1. MH's Recommended Version

The methodology used for the Cost of Service Study was changed for each of the following studies (suggesting, as was stated by the Board in Order 117/06, that COS is 'in a state of flux'):

- PCOSS-99
- PCOSS-01
- PCOSS-02
- PCOSS-04
- PCOSS-06
- PCOSS-08

13.4.1 Compliance with Board Order 117/06

Board Order 117/06 directed MH to re-file COS as presented in “PCOSS 06 - Recommended Method” on the basis of directives provided by the Board. The following identifies the Board’s directives and the extent of MH’s compliance.

One Export Class

MH defined a single export class encompassing both firm (dependable) energy exports and interruptible (opportunity) energy exports. Costs were either to be assigned directly or allocated on the basis of total export energy sales.

However, MH has not specifically defined the export operation as a class for regulation purposes.

Uniform Rate Adjustment

As per Order 117/06, MH credited the residential, general service small, and the area and roadway lighting classes with appropriately calculated energy-based shares of foregone revenue incurred as a result of the Uniform Rate Adjustment (URA). URA, established by provincial legislation, provides for all grid-served customers to receive the same rate, pursuant to the Board’s class rate schedule.

The URA provides significant savings to rural and grid-served northern communities, compared to the previous approach which established grid rates by customer zone, with rural and northern zones being allocated higher proportional costs to serve that urban areas. Grid-rates have also been provided to residential customers served by diesel-generated power in the four northern communities still not on the grid.

The full amount of the adjustment has been deducted from the total export revenues, the assumption being that the URA has been "paid for" by export profits.

Imports and Power Purchases

As per Order 117/06, MH directly assigned all energy import and wind energy purchase costs as costs to be allocated against export revenues. Import energy costs include energy actually transmitted into the MH system and energy purchased for immediate resale (arbitrage) in the external export market. These latter energy amounts have been deducted from exports in determining the export class' share of overall costs.

Thermal Generation

MH's interpretation of Order 117/06 resulted in the Utility directly assigning only thermal fuel (coal and natural gas) costs at $19.3 million/year to the export class. Other generation costs, totalling $69.3 million/year for finance, depreciation, and OM&A, were not directly assigned, but placed in the generation pool for overall system cost-sharing customer classes.

However, MH elected to deduct the full amount of thermal generation (587 GW.h) from exports in determining the percentage of generation costs to be shared by exports. This interpretation by MH results in no embedded costs being allocated to the export class for the 587 GW.h thermally-generated electricity. The net effect was to reduce costs otherwise allocated to the export class by approximately $10 million.

Overall, MH's approach reduced the unit cost assigned to exports by nearly 1¢/kW.h. MH rationalized the deviation from the Board's instruction of Order 117/06 on the basis that while fuel costs fluctuate with export levels, the other costs do not. And, these other costs relate to fixed plant, and that the thermal plants were constructed to provide added security of reliability to domestic load demand requirements.

DSM Energy Deduction

In keeping with Order 117/06, MH charged all DSM costs directly to the export class. However, MH also deducted the DSM energy savings from exports in defining the export class share of hydraulic generation costs.

If DSM costs were allocated to exports (as per the Uniform Rate Adjustment), but energy savings were not, about $28 million of generation costs would be shifted from domestic classes to export class.

The longer-term result of MH's approach to the DSM energy savings, if accepted by the Board, would have very little (if any) generation costs being allocated to the export class; this, because DSM-derived energy savings could outstrip actual exports by 2017/18.

Energy Weighting (12 periods)

As per Order 117/06, in the cost allocation process for Generation energy supply, MH employed a 12-period price weighting rather than the four periods at initially proposed in PCOSS-06. The weighting was based on energy values during both the four seasons and the peak/shoulder/off-peak periods. The weightings in the following table reflect the average from January 1999 to December 2006, relative to a summer off-peak base value of 1.000.

The relative value of energy supply resulting were:

	Peak	**Shoulder (¢ per kW.h)**	**Off-peak**
Spring (2 months)	2.513	2.144	1.246
Summer (4 months)	3.258	2.388	1.000
Fall (2 months)	2.624	2.155	1.396
Winter (4 months)	3.406	2.262	1.796

The energy consumption values employed in the generation cost allocation process by MH reflected the domestic and export energy consumption profiles for 2003/04 in PCOSS 06 (a drought year) and for 2005/06 in PCOSS 08 (a high flow year). Consequently, the generation cost allocation to exports are quite different in the two PCOSS'.

13.5 PCOSS-08

13.5.1 Treatment of Exports Class Cost Allocations

In Board Order 117/06, MH was directed to establish a single export class, to be fully allocated costs for generation and transmission. MH opposed this direction opining that opportunity sales should only attract variable costs and not fixed costs. This view was reflected in MH's treatment of thermal costs, where MH assigned only fuel costs to the export class in contravention of the Board's directive.

13.5.2 Review of PCOSS-08

PCOSS-08 employed the following energy inputs:

Domestic Load at Generation	23,740 GW.h
Export Load at Generation	8,460 GW.h
Total Load at Generation	32,200 GW.h

Forecast Revenues in PCOSS-08

Forecast Domestic	- $1,066 M (20,800 GW.h @ 5.13¢/kW.h at meter) (actual average export prices in 07/08 were 5.0¢/kW.h)
Forecast Export	- $551.5 M (7,700 GW.h @ 7.16¢/kW.h at point of sale)
	(While the above were forecast, the actual average export prices in 07/08 appear to be 5.0¢/kW.h)

For hydraulic generation cost sharing purposes, export load would be reduced as follows:

	GW.h
Export Load at Generation	8,462
Less	
Served from imports and power purchase	(2,028)
Served by thermal generation	(560)
DSM savings	(1,350)
Net exports served from hydraulic generation pool	4,524

13.5.3 Treatment of Exports Class Cost Allocations

Out of a total generation and transmission cost of $1,165 million , PCOSS-08 defined export costs as follows:

Directly Assigned Costs

Uniform Rate Adjustment		$17 M
DSM Costs		$25 M
Trading Disk Costs		$13 M
MAPP/MISO/NEB Costs		$7 M
Imports and other purchased power		$134 M
Thermal Fuel Costs		$23 M
	Sub-total	**$219 M**

Allocated Costs

Generation (including water rentals)		$116 M
Transmission		$51 M
	Sub-total	**$167 M**
Total export costs		**$386 M**

Export sales accounted for 27% of system energy sales, about 20% of winter CP demand and 33% of summer CP demand.

The $386 million of defined export costs equates to approximately 5¢/kW.h at the point of sale – and were derived by MH without assigning “fixed” thermal costs to the export class as directed by the Board. While MH’s forecast export sales prices in PCOSS-08 were 7.2¢/kW.h, it now appears that the actual average export price will be closer to 5¢/kW.h

MH Position

MH contends that its current COSS model, as depicted in PCOSS-08, does not provide the most suitable basis for evaluating either class revenue requirements or establishing a rate design. MH’s fundamental issue with PCOSS-O8 relates to the magnitude of assignment (allocation) of costs to Exports.

The ultimate impact of the Board’s directives with respect to these matters was depicted in the pre-filed evidence of Patrick Bowman and Andrew McLaren, witnesses for MIPUG. In their Table 4-1, Bulk Power costs are depicted for each of the major classes, as follows:

Table 4.1
Levelized RCC Ratios per kW.h PCOSS08 with DSM Correction

	Residential		GSS-ND		GSM		GSL>100kV		Exports	
	($ M)	(¢/kWh)	($ M)	(¢/kWh)	($ M)	(¢/kWh)	($ M)	(¢/kWh)	($ M)	(¢/kWh)
Costs										
1 Bulk Power Costs	$248.8	3.78	$54.8	4.12	$113.2	3.84	$171.1	3.29	$372.2	4.83
2 DSM adjustments	($4.2)	(0.06)	($3.2)	(0.24)	($4.2)	(0.14)	($6.6)	(0.13)	$24.6	0.32
3 Net Bulk Power Costs	$244.6	3.72	$51.6	3.88	$109.0	3.70	$164.5	3.16	$396.8	5.15
4 plus: Subtransmission-related	$38.5	0.59	$6.8	0.51	$11.7	0.40	$0.0	0.00	$0.0	0.00
5 plus: Distrib. and Cust. Serv.	$229.7	3.49	$42.1	3.16	$39.7	1.35	$2.0	0.04	$0.0	0.00
6 **Total Costs**	**$512.9**	**7.80**	**$100.4**	**7.56**	**$160.5**	**5.44**	**$166.4**	**3.20**	**$396.8**	**5.15**
Rates										
7 Total Sales Revenue	$417.8	6.35	$91.7	6.90	$144.2	4.89	$164.0	3.15	$490.3	6.36
8 Uniform Rate Credit	$15.4	0.23	$1.2	0.09	$0.0	0.00	$0.0	0.00	($17.2)	
9 System Merchant Sales									$61.2	
10 **Total PCOSS Revenue** (7 + 8 + 9)	**$433.1**	**6.59**	**$92.9**	**6.99**	**$144.2**	**4.89**	**$164.0**	**3.15**	**$534.3**	**6.93**
Surplus/Shortfall before Net Export Credits										
11 **Rates compared to costs** (10 - 6)	**($79.8)**	**(1.21)**	**($7.5)**	**(0.57)**	**($16.3)**	**(0.55)**	**($2.4)**	**(0.05)**	**$137.5**	**1.78**
Net Export Credits										
12 Net Export Revenues Allocation	$58.6	0.89	$11.5	0.86	$18.3	0.62	$19.7	0.38	($137.5)	(1.78)
13 **Surplus/(Shortfall) after net export revenue credits** (11 + 12)	**($21.1)**	**(0.32)**	**$3.9**	**0.30**	**$2.0**	**0.07**	**$17.3**	**0.33**		
Total Class Metered Energy (GW.h)	6,578		1,329		2,949		5,202		7,707	

The table illustrates that for transmission voltage domestic customers (General Service Large > 100kV), MH's embedded historic cost per kW.h is 3.29¢ compared to 4.83¢ for the Export Class. In fact, bulk power costs for Generation and Transmission (G&T) for all domestic classes are lower than the costs allocated to exports. MH opined that the view was counterintuitive, and that the embedded bulk power (G&T) cost of export sales should not be higher, on a unit basis, than the embedded cost to Transmission voltage domestic customers, and probably should be lower than the embedded cost of similar voltage domestic sales.

Board Order 117/06 also directed that certain other costs be specifically assigned to the Export Class, including the revenue impacts of Uniform Rates and the costs of DSM for domestic customers.

MH contends that the directed methodology of Order 117/06 assigns a much larger portion of Generation and Transmission costs against exports, and thus reduces the amount of residual export revenue available for allocation to domestic customer classes. This approach would appear to have the same effect on class RCC ratios as previous methodologies, in which the allocation of export revenues to the domestic rate classes was limited to only the Generation and Transmission functions.

With respect to DSM costs, MH interpreted Order 117/06 to mean that all DSM energy savings should be assumed to serve the export market. Accordingly, the $24.6 million in forecast DSM costs and the associated 1,350 GW.h of annual energy savings associated with all DSM carried out to-date were applied to the Export Class.

If the Board continues to direct DSM and thermal costs be assigned to exports, MH recommends that the Board confirm the treatment proposed by the Corporation for PCOSS08. However, MH reiterated that the Corporation has serious overall concern about what it perceives as an over-allocation of costs to Exports, with resulting deleterious impact on the outputs of the embedded cost study.

13.6 Marginal Cost Considerations

In Board Order 117/06, MH was directed to provide a strategy to allow for the consideration of marginal costs and environmental costs, in addition to the current embedded costs, within the COS. In the current Application, MH provided a single page marginal cost analysis without explanation or suggestion as to how the analysis would best be applied in the context of rate design.

Briefly, MH's marginal cost calculations assumed that for:

- **Generation**: All domestic customer classes should be allocated costs on the basis of annual consumption applied to forecast peak (5 x 16) export prices. (No costs were to be assigned to the export class.)

- **Transmission**: All domestic customer classes should be allocated costs on the basis of two coincidental peak (2 CP) peak load cost sharing of future additions to in-service assets, plus OM&A costs. (No costs were to be assigned to the export class.)

- **Distribution**: All domestic customer classes should be allocated costs on the basis of (NCP) peak load cost sharing of future additions to the assets in-service plus OM&A costs.

The proposed methodology was subsequently amended during the hearing; the revisions dealt with numbers employed but did not address how the RCCs calculated should be applied to rate design.

In the absence of disclosure of key assumptions (deemed commercially sensitive by MH), it is unclear to the Board as to how MH determined key inputs to the marginal cost calculations. For example, it appears that no generation or transmission investments were allocated to exports. And that no costs for water rental, imports, fuel, transmission losses, etc. were deducted from forecast export prices, employed in assigning marginal costs for generation to domestic customers. High levels of distribution investments in the distribution plant over the last ten years were not reflected in marginal cost going forward.

MH’s filing on marginal cost was subsequently amended by MH, and presented marginal cost values for:

- Generation - $1.315 billion (equivalent to 20,800 GW.h @ 6.32¢/kW.h) allocated to various classes on SEP weighting basis and is essentially based on export market values;
- Transmission - $280 million (equivalent to 20,800 GW.h @ 1.35¢/kW.h) is allocated to various classes on a 2 CP basis and reflects the cost of all new transmission plant; and
- Distribution - $294 million ($133 million for distribution plant and $161 million for OM&A costs) allocated to various classes, as applicable, on a NCP basis.

There is no readily apparent definition of marginal cost, although MH’s approach could be taken to represent the cost of providing each additional increment of energy, demand, or service (as these requirements grow). It could also be taken to mean the value of the last increment already supplied.

MH’s approach suggests that marginal cost could be a stand-alone COSS, rather than being incremental to the existing embedded cost of service study.

Marginal cost of service methodology is complex and, to the Board’s understanding, has only been employed for rate setting by a limited number of electric utilities. It could be argued that it is not readily applicable to MH’s circumstances that being a vertically integrated utility with surplus energy going into a competitive export market.

13.7 Interveners' Positions

The Coalition

The Coalition cited a changing face of consumption among the various customer classes, noting that annual consumption from General Service top customers are projected to exceed residential customers by 2009/10 and are projected to be significantly higher than residential sales by 2017/18.

The Coalition further noted that average gross export rate prices for fiscal 2007/08 and fiscal 2008/09 were forecast at 5.4¢ per kW.h and 5.6¢ per kW.h respectively. This compares with an average residential rate above 6¢ per kW.h, while the average GSL greater than 100 KV rate is less than 3.5¢ per kW.h. The Coalition observed that residential rates are closer to marginal rates than those of large industrial customers. Current residential rates are 6¢ per kW.h while the long run marginal cost is 7.6¢ per kW.h, as compared to GSL greater than 30 KV with a current rate of 3.2¢ per kW.h while the long run marginal cost is approximately 6.8¢ per kW.h.

The Coalition suggested that the Board's objective is to look at the results of a marginal cost based cost allocation and use it to help inform decisions with respect to revenue allocation to customer classes. The Coalition prefers MH's approach, while considering MIPUG's approach to be better suited to a situation where one wants to incorporate marginal cost principles in an embedded COSS (as opposed to doing a marginal cost based COSS).

The Coalition noted the allocation of generation costs using the SEP prices is an example of where MH is utilizing an approach very similar to MIPUG's (i.e., determine the marginal cost for a function and use them to allocate the cost of that function). The Coalition further noted if the Board wanted to review the implications of using a marginal cost based COSS it should not look at the end results proposed by MIPUG, as MIPUG's approach distorts the results by forcing a reconciliation to the embedded cost approach on an individual function basis.

With respect to whether the differential rate increases should be based on the new cost of service study, Mr. Harper noted that the Board has directed that the zone of reasonableness (ZOR), a range of between 95% to 105%, be considered, and that some minor rebalancing might be appropriate given that three out of the eight classes are outside the range, though some only marginally.

However, Mr. Harper further stated this represents the first time that the revised cost of service study has been reviewed and that there remain some methodology issues that require resolution. Therefore, given that the RCCs are relatively close to the ZOR boundary, for Mr. Harper it would be appropriate to resolve the outstanding issues before entering into rate rebalancing.

In addition to cost of service study results, the Board has indicated that it may consider a number of other factors in assessing the revenue allocation between the classes, including the pre-export allocation as well as an allocation based on marginal environmental costs.

Mr. Harper noted that given various exhibits filed by MH and others these varying perspectives yield significantly different results, and depending upon how much weight one puts on one perspective as opposed to another can result in totally different view as to what differentiated rate increases would result to the customer classes. In addition, Mr. Harper noted that MH is seeking an increase that is higher than inflation and that differentiated rate increases would compound a negative impact for some customer classes.

The Coalition concluded that, except for Area and Roadway Lighting, there should be no differential rate increases at this time.

MIPUG

MIPUG stated the current COSS fairly reflects the embedded cost of service with the exception of the treatment of DSM. For MIPUG, MH has correctly assigned the DSM costs to the export class as directed by Board Order 117/06, however MH has also deducted 1,350 GW.h in DSM savings from the export energy used to allocate common generation pool costs.

MIPUG stated that as these same DSM Energy savings are accounted for in the domestic sales forecast, MH's treatment has erroneously double-counted the DSM Energy savings, and created an energy imbalance in PCOSS-08.

MIPUG stated MH's approach also effectively "claws back" from the common generation pool a priority allocation of generation to exports. The result being that for all intents and purposes the benefits secured from the domestic classes' participation in DSM is lost. MIPUG suggested that the Board's directive in Order 117/06 did not specify a specific treatment of DSM energy. As MH's treatment results in an energy imbalance in the PC0SS-08, MIPUG recommended the issue must be addressed.

MIPUG recommended that the Board direct MH to address the error by removing the 1,350 GW.h DSM Energy credit from the export class. MIPUG submitted the DSM costs should continue to be directly assigned to the export class but that the energy savings should remain with the domestic customer classes that undertook the measures leading to the savings.

MIPUG further stated that PCOSS-08 also failed to strictly reflect the Board's directive from Order 117/06 as to the assignment of all thermal plant costs to exports. (MH assigned only fuel to the export class, with the remainder of thermal plant costs allocated to the overall generation pool.) Yet, although the approach did not strictly conform to the Board's directive, Mr. Bowman stated MH's treatment does not appear unreasonable as thermal assets are a necessary complement to the hydraulic assets and, as a result, merit treatment as common pool generation assets. MIPUG recommended the Board approve MH's treatment of thermal costs in the COSS.

MKO

MKO concurs with the MIPUG recommendations on the 2008/09 COSS. MKO did not provide recommendations on whether embedded versus marginal costing should be utilized or whether rate increases, if granted, should be set on a differential basis.

MKO noted that it was reasonable to identify how additional environmental costs were included in PCOSS-08. In general, MKO supports greater consideration of environmental costs being given and advised it would continue to argue for a fair share of environmental benefits to accrue to MKO communities. MKO recommended that future PCOSS should quantify both environmental benefits and costs.

RCM/TREE

RCM/TREE observed that this GRA was the first to employ the new cost of service methodology, which treats export customers as a separate class and defines a revenue surplus arising from that class.

RCM/TREE noted that all domestic customer classes have a revenue shortfall relative to allocated costs, and are subsidized by export surpluses. RCM/TREE stated that this reality raises a policy question, that being how best to distribute export surplus (to the elements, activities, and classes of the utility).

RCM/TREE stated that general service large customers should be charged the embedded energy rate for usage up to a baseline, and assessed marginal cost, including environmental costs, for consumption above that level. RCM/TREE also recommended that new general service large customers should be charged the marginal energy rate. For the intervener, additional revenue raised through the implementation of the recommendations would best be used to fund economic development grants, increase DSM efforts, and to decrease demand charges.

RCM/TREE recommended that the Board direct MH to participate in a public review of marginal costs, and that those costs include environmental costs. RCM/TREE further submitted that if MH’s forecast data is to be considered commercially sensitive, then publicly available information should be used to satisfy the Board's directives of Order117/06. RCM/TREE stated that MH had not satisfied the Board’s directive, by including only environmental costs internalized in the market, and that those costs are only part of the full costs of full cost accounting, which should inform decision-making as prescribed by guideline one of *The Sustainable Development Act.*

Mr. Chernick stated that reducing domestic consumption would either lead to increased exports, reduced imports, or reduced MH's thermal generation, and that all of these possible outcomes would result in reduced GHG emissions. According to Mr. Chernick, currently the "costs" of greenhouse gases are not internalized in the prices charged by U.S. utilities.

Mr. Chernick submitted that the total social cost of domestic consumption of electricity is thus higher than the direct costs as calculated by MH. Mr. Chernick recommended that such additional environmental costs should be incorporated in marginal costs and reflected in the COSS, although the benefits flow to the U.S. and reduce environmental costs incurred in the U.S.

Mr. Chernick recommended that MH's rate design should be based on marginal costs, not embedded cost. and that the current COSS is based on a faulty model of cost causality, as it ignores the effects of energy use on transmission and distribution (T&D) costs.

Mr. Chernick stated that the transmission and distribution system is impacted by energy in at least three respects:

First, a large portion of MH's transmission is required to move power from remote hydro stations in the north to the load centers located in the south, and for export. Second, MH's transmission system is more expensive because it is designed to allow for large transfers of energy between neighbouring utilities. Third, MH's transmission system is designed to minimize energy losses over extended hours of high loads. Mr. Chernick submitted that were the system designed only to meet peak demand, a less costly system would suffice and, in some cases, lines or circuits now in place would not be required, voltage levels could be lower, and fewer or smaller transformers would be needed.

Mr. Chernick stated that MH's distribution costs are impacted by energy requirements, and that the sizing of transformers and underground lines are driven by the energy use on the equipment in high-load periods, in addition to maximum hourly loads. Mr. Chernick also stated that similar high load energy usage affects the service life of transformers as well as impacts the cost of other components of the transmission and distribution system.

For Mr. Chernick, high-load factors impact the sizing of underground transmission, primary, and secondary lines, and he stated that since heat builds up around hydro lines, the length of peak loads and the amount of load relief in the off-peak period affect the sizing of the underground lines.

Mr. Chernick further stated that since the number and sizing of underground lines is a function of load factor, a portion of the cost of the lines should be recovered through energy charges, even if demand charges could reasonably measure the contribution of customer loads to peak demands on distribution equipment.

Mr. Chernick concluded that there is a cost causation relationship between energy, transmission and distribution costs. Reflecting these effects by incorporating transmission and distribution costs in energy charges rather than demand charges, would, for Mr. Chernick, encourage energy efficiency. Accordingly, he recommended that a portion of the cost of transmission and distribution facilities should be allocated to customer classes based on energy.

RCM/TREE suggested that MH's reluctance to release marginal cost information goes beyond the restrictions placed by most other utilities in North America. And, while **MIPUG** supported MH's need for non-disclosure of commercially sensitive price data, RCM/TREE cautioned against excessive restrictions on the release of information, as without the information, rigorous testing cannot be achieved.

In short, **Coalition and MKO** alluded to the need for transparency and did not support the Board accepting information in confidence from the utility.

13.8 Board Findings

Embedded Cost of Service

(i) The Board will require future COSS regulatory filings to incorporate the export and diesel zone classes in the same fashion as other customer classes (i.e., separately disclosed, and including all exports in all COSS calculations and charts).

ii) The Board considers MH's interpretation of the Board's direction as to what thermal costs to assign to exports to essentially constitute a "Motion to Review and Vary Order 117/06". While MIPUG agreed with MH's interpretation, the Board reiterates its requirement that MH is to assign fixed costs as stated in Order 117/06 and allocate them to the export class, (including the $69.3 million/year for finance, depreciation and OM&A of thermal plants).

The Board understands that this will result in more costs being allocated to the export class, and that as a result unit export costs will rise above 5¢/kW.h.

The Board also accepts the risk that the stricter interpretation of the directions of Order 117/06 may result in zero or negative net export revenues in some future years. For example, in 2006 MH assigned $386 million of costs to the export class, representing a unit cost basis of approximately 5¢/ kW.h. By assigning $69.3 million of additional costs to the export class, the total cost will increase to $455 million, or approximately 6¢/kW.h.

When Brandon Coal Generation is restricted to emergency use only (in accordance with the government's direction), the allocation of costs to the export class will decrease, assuming MH doesn't replace coal with natural gas generation (e.g., combined cycle combustion turbine).

In reaching this conclusion, the Board also discards the option of directing MH not to deduct the 587 GW.h of energy from the total export energy costs and only assign fuel costs to exports. To take this route would have increased total allocated costs to the export class for generation by $10 million ($396 million as compared to $386 million). And, restriction of the Brandon plant would essentially eliminate the fuel cost and energy deductions for average year scenarios (and, the estimated $10 – 20 million of annual net income attributed to current coal-fired generation.

The Board understands that the rationale to support MH's rejected option (i.e. not charging thermal finance and depreciation charges against the export class) is that the thermal plants provide dispatchable energy, increase dependable energy for export, and enhance the reliability of domestic energy and, as such, all non-variable costs should be shared by both domestic and export classes.

However, for the Board to allow the approach favoured by MH and MIPUG would mean the Board would reject the principles of cost causation and would be avoiding a proper allocation of costs (of the thermally generated component of exports).

The Board observes that with the pending restriction on the Brandon plant, the Board's direction will have less of an effect on the average cost of export class generation; that is, unless MH moves to increased natural gas generation. At this time the Board will amend its Order 117/06 directive and assign all fuel costs and 50% of the fixed costs to the Export class. Upon the coal plant going into emergency service status, the allocation will be further reviewed.

(iii) Re: DSM: MH's approach to charging DSM costs to exports and deducting DSM energy saving from the export class results in an arithmetic imbalance in the energy generation calculation, and could ultimately result in zero generation cost allocations being made to the export class.

Because DSM-originated energy savings reduce domestic consumption, prior to determining available energy for export, DSM energy savings should be added back to the domestic loss component, to determine the percentages for generation cost-sharing.

(iv) The energy consumption values employed in the generation cost allocation process by MH reflected two distinct consumption profiles for both domestic and export energy - one for 2003/04, which was a period of drought, and the other, 2005/06, a year of high water flows.

Consequently, the generation cost allocations to the export class were quite different in the two studies. Compared to the 8-year price period, the drought year costs would be overstated, and in the high flow years, those costs would be understated. Accordingly, it would be preferable to utilize the same 8-year time period for weighting both prices and consumption.

(v) In making its closing submission, MH remained critical of Order 117/06's "considerable" cost allocations to the export class, particularly with respect to:

a) Imports (no reduction for domestic load support);

b) Thermal generation costs (fuel costs not shared by domestic load);

c) Degree of embedded costs going to both firm and opportunity exports (with MH contending that no fixed costs should be directed at opportunity sales in the export class). That argument by MH was heard and rejected by the Board at the earlier Cost of Service Review proceeding;

d) DSM (costs should only be directed to export class if energy savings are credited to export);

e) Uniform Rates Adjustment (a legislated provision); and;

f) Trading Desk/MAPP/MISO costs (no reduction for domestic load support).

The Board previously found that MH is designing and building greater generation and transmission plant capacity to achieve additional opportunity sales. Therefore, those extra costs incurred in that effort should be allocated to the export class; with the emphasis being placed on total exports, exports can no longer be viewed as “by-products” of MH’s system.

In reality, exports tend to employ the last units of generation and could arguably, and fairly, be costed (if not priced) on a marginal cost basis.

The Board decision in 117/06 appears consistent with MH’s Power Resource Plan, in which hydraulic generation capacity in excess of dependable flow is not used to supply either domestic load or firm export contracts. Typically, dependable flow from MH’s hydraulic stations represents less than 60% of installed capacity. Therefore, the balance of plant capacity can be utilized in most years to produce energy for additional opportunity export sales.

MH's position that export cost allocation should be no greater than GSL > 100 cost allocations has only limited merit. Intuitively, one could argue that generation and transmission (G & T) costs relate to common energy sources, which should be shared on an equal access basis. This suggests export load has equal status to domestic load.

Alternatively, the counter argument is that domestic load has covered the past investments in G & T, and is entitled to "Heritage rates". Hence, exports should use and carry the cost of newer assets on an incremental cost basis. Examples are:

- Imports (not usually required for domestic load);
- Thermal (not usually required for domestic load);
- Transmission (losses increase exponentially with added export loads); and
- New Generation (built to serve export contracts)

The current COSS falls between these two positions, and assigns imports and thermal fuel costs directly to exports while allowing exports to share in the overall blended costs of generation and transmission (without regard for vintage pricing). The approach does not make exports solely responsible for incremental embedded costs or marginal costs for energy.

Government and Board directives have assigned the costs of the uniform rate adjustment and the evolving DSM programs to exports. These must be considered as societal benefits, the charges for which do not vary with MH's actual energy sales on either the export or domestic fronts.

Use of Marginal Costs in COSS

MH argued that there is sufficient data on the public record to support the marginal cost values it advanced. While there may be sufficient data, the key assumptions are lacking, and are required to confirm MH's marginal cost forecasts.

MH's marginal cost for generation appears to assume an unlimited market for MH's entire energy output at 5 x 16 peak prices. Because of inter-tie transmission capacity constraints, MH can only achieve that pricing for about 7,700 GW.h of energy. In addition, firm export commitments and deliveries now fully utilize the entire tie-line capability during median flow scenarios. Consequently, new energy coming from load reduction or new plant can only earn off-peak prices.

Accordingly, the value of export energy for marginal cost purposes should be estimated to be substantially lower than the $1.315 billion suggested by MH. And the reduced amount should be further reduced by deducting appropriate costs; the Board is of the view that current export prices and market conditions do not support marginal costs of 6.3¢/kW.h for generation.

Greater inter-tie capability during the 5 x 16 period could become available when the newest export contracts go on-line, but these would likely be fully utilized by Conawapa and Keeyask. Output reductions in domestic load through DSM activities would still not be able to earn on-peak prices if that energy were exported, given transmission capacity and MISO demand limitations.

MH's marginal cost for transmission appears to reflect significant new plant requirements during the next two decades ($240 million/year of financing and depreciation costs would equate to about $3 billion of plant upgrades or expansions). The most obvious new facility, Bipole III, is being built for domestic reliability and new export loads and not for domestic load growth. The expected cost of the project was also largely allocated to the generation function in PCOSS-08. As such, most of its costs should not accrue to the domestic transmission marginal cost.

MH's marginal cost for distribution appears to be derived from a forecast of plant investment level that is considerably lower than actual capital expenditures on distribution plant over the past decade. The resulting substantially-lower marginal cost of distribution (compared to embedded costs in PCOSS-08) raises a question as to how the embedded (sunk) costs for distribution should be recovered.

The projected overall marginal cost for generation and transmission provides a perspective of what additional revenues could be extracted from domestic customers if they were to be treated as an export customer by an externally-owned utility providing only generation and transmission services. With respect to MH's current mandate, the generation and transmission marginal cost values are seriously flawed and, in the current form, should not be considered as a basis for rate adjustments.

MH has not presented any compelling arguments to support its marginal cost calculation, and reference to multi-year analysis in the SPLASH model, using undisclosed (confidential) inputs and assumptions, does not allow for any critical review or instil confidence in what would best be a transparent process.

Furthermore, MH has implied marginal cost is a separate (free standing) cost coverage process that can be compared to embedded costs. In reality, marginal cost should be treated as being only incremental to embedded costs. Historical costs still need to be recovered.

MH has suggested that available public information on actual export sales and prices is sufficient for the Board and Interveners to test the validity of the Corporation's projected marginal cost value(s). Reference was made to MH's SEP and NEB's cross-border trading data, and MISO clearing prices, etc., as useful and valid sources of information for defining marginal cost.

MH's position is only partially correct. The marginal cost identification process involves critical key assumptions (i.e., quantity of energy that has marginal cost value, transmission assets being acquired for export versus domestic load expansion, and the distribution assets which are due to load expansion). For better transparency, the Board will direct MH to file all appropriate data (e.g. SEP/ NEB/ MISO clearinghouse information and avoided cost information etc.) required for input to the marginal cost determinations for generation, transmission and distribution and to further define the key assumptions employed by MH in support of this process with the Board (on a confidential basis if necessary) on or before December 1, 2008.

Forecast Export Price Input

In MH Exhibit #68, it appears that a forecast export energy price of 7.48¢/kW.h (6.32¢/kW.h for generation and 1.16¢/kW.h for transmission) at the meter has been employed in the marginal cost calculation. This rate is difficult to rationalize given that average export prices have been about 5.0¢/kW.h for generation and transmission over the last three or four years. The Board may be compelled to direct the release and use of actual prices rather than forecast unless more transparency is displayed.

MH has suggested that historical price data has been corrected upward to reflect market conditions for electrical energy under median flow scenarios. And, this would seem reasonable given that recent years have seen above average to high flow situations which result in a greater proportion of off-peak sales, effectively driving the average export price down. However, that scenario is flawed because, in the Board's considered opinion, MH has not and cannot support its forecast of achieving an energy price of 7.5¢/kW.h based on known existing export circumstances:

Median flow scenario reflects 7,700 GW.h of export energy in 07/08, which theoretically could all be 5 x 16 peak energy, but about half would be covered by contract prices at about 5.5¢/kW.h. While the remaining peak energy might achieve 7.0¢/kW.h, it would appear that the overall average cannot reach 7.5¢/kW.h.

Dependable flow scenario reflects 4,000 GW.h of export energy, all of which could be 5 x 16 peak energy and covered by existing contracts at 5.5¢/kW.h, this well below the 7.5¢/kW.h forecast; and the high flow scenario reflects 11,700 GW.h of export energy, of which about 7,700 GW.h could be 5 x 16 peak energy including existing contracts at 5.5¢/kW.h, and 4,000 GW.h would be off-peak energy in a surplus market pricing at below 3¢/kW.h, which brings down the overall average to about 5¢/kW.h.

MH suggests export pricing will escalate in tandem with rising natural gas prices. However, this assumption is contrary to the experience over the past 4 or 5 years.

In the determination of generation marginal cost, MH applied a marginal cost, derived primarily from forecast export prices, to the entire domestic energy consumption (20,800 GW.h as metered), and arrived at a marginal cost of domestic generation of $1,315 million (or 6.3¢/kW.h at sales).

Unfortunately, MH's scenario appears unrealistic and unattainable, because:

a) the calculation suggests MH expects to export 20,800 GW.h over and above the existing export level of 7,700 GW.h, when maximum tie-line capabilities are only about 16,000 GW.h;

b) the forecast suggests it is possible to achieve peak (5 x 16) export prices above 6¢/kW.h for an additional 20,800 GW.h, although the peak period tie-line capabilities are limited to about 7,500 GW.h and are already fully committed;

c) with existing export sales contracts of 4,000 GW.h for 5 x 16 energy at current average prices of 5.5¢/kW.h, and assuming the sale of the entire remaining 3,500 GW.h of peak energy and 8,500 GW.h of off-peak at average prices of 9¢/kW.h, when MH's average price for exports has been about 5¢/kW.h for both generation and transmission, this suggests the projection is not realistic;

d) to transmit 16,000 GW.h/year of energy into the MISO market and not see average prices decline below 5¢/kW.h seems unlikely; and.

e) shifting domestic load of 8,300 GW.h (16,000 GW.h minus 7,700 GW.h median flow exports) to export would appear to yield additional revenue of about $415 million at today's average export prices. Given this could not be at 5 X 16 peak pricing, this appears to suggest a marginal cost of about 2¢/kW.h when applied to the entire 20,800 GW.h of domestic load. (This compares to the $615 million (or 3¢/kW.h) of embedded costs allocated to domestic load for generation in PCOSS-08.)

The foregoing review suggests that the marginal cost scenario for generation presented by MH is flawed and in need of revision. It also suggests that the RCCs that arise are being driven by an overstatement of generation marginal costs.

Only MIPUG, of the Intervener groups, provided comment on MH's marginal cost calculations for generation. They submitted an alternative that assigns embedded costs on an energy price (SEP-based) weighting basis.

In MH Exhibit #68, MH applied unit marginal cost for distribution to the entire load served from the distribution system. In a previous MH filing (Marginal Cost of Transmission and Generation Study of 2004), the authors suggested that the values derived were only applicable to load growth or reductions of 85 MW and should not be extrapolated further.

Accordingly, MH will be directed to revisit and re-file a better-formulated marginal cost/value, one reflecting the realities of covering embedded costs as well as future costs, and as to potential export revenues. The re-filing should include an in-depth discussion of assumptions and inputs to MH's marginal cost COS. The re-filing should also cover the marginal costs of the export class.

As for use of marginal costs and the use of RCCs in rate setting, the Board will require the additional information from MH before assessing the weighting for embedded cost RCCs and marginal cost RCCs. Presumably, the marginal cost recalculation will be equally applicable to the Energy Intensive Industry rate design.

Marginal Cost Confidentiality

MH declined to publicly present its key assumptions and specific input data that it employed with its SPLASH model in the determination of generation marginal cost. Similarly, the "avoided cost" calculations, employed in defining transmission marginal cost and distribution marginal cost, were also not made available to the proceeding.

The Board will direct MH to make all this information available (however, on a confidential basis to the Board) and will assess whether the information should be further shared with interveners. The Board will not share the information with interveners without first engaging MH in discussion ahead of a meeting to involve all parties.

During the hearing process, MH invoked a confidentiality constraint on the specifics of:

a) How forecast export prices were determined;

b) SPLASH model inputs and assumptions;

c) Transmission marginal cost assumptions and avoided cost calculations; and

d) Distribution marginal cost assumptions and avoided cost calculations.

The result is that none of the interveners were in a position to challenge the marginal cost determined by MH for generation, transmission, and distribution. While MIPUG provided an alternative to MH's calculation process, the intervener did not attempt and probably could not have challenged the unit marginal costs and/or forecast export prices.

This left the Board in the position of either accepting MH's forecast marginal cost, despite the absence of any serious testing, or directing MH to provide more detailed justification for the marginal cost calculations. The Board opts for the latter.

Forecast and Calculation of Marginal Cost

The Board suggests that MH's forecast of export prices is overstated and does not adequately recognize:

a) Current U.S. export market prices;

b) Current USD/CDN exchange rates; and

c) Current transmission inter-tie capacity to U.S. constraints.

Further, the Board has concerns about MH calculations of marginal cost for generation, specifically the total marginal cost value assigned to domestic generation. Also, as previously outlined, the Board has concerns about the lack of information (assumptions and inputs) on the transmission and distribution marginal cost provided to the proceeding.

Weighting of MC-COSS

Given this, the Board cannot establish, other than directionally, the value of the marginal cost (MC) as a COSS consideration. Much more marginal cost information and justification will be required from MH in advance of the next GRA, to allow the Board to place a weighting on the two sources of RCCs, and begin to differentially allocate future rate increases.

Therefore, the Board will not be assigning a specific weighting to the MC-RCC developed by MH, or for the amended approach proposed by MIPUG. However, after a review of the information put before it, the Board remains of the view that, in a proper form, marginal cost consideration should be given comparable weighting to that of the embedded COSS.

While previously the PCOSS was viewed to be a stand-alone tool for rate setting, it does not appear that a marginal cost determination could be other than a modifying procedure. In any event, appropriate generation and transmission costs should be allocated to the export class.

The Board therefore directs MH to provide a revamped MC-COSS analysis, one reflecting needed refinements to generation/transmission/distribution marginal costs. One scenario to be explored, among others, should involve the addition of marginal cost to embedded costs in COSS for domestic classes and the export class, prior to comparison to class revenues.

Environmental Consideration in COSS

Despite MH's contention that export pricing automatically builds in environmental considerations, it is apparent that MH, at least to date, has been unable to gain significant revenue increases of any kind related to environmental factors. Environmental or green energy considerations do not, at least at present and by no means for lack of effort on the part of MH or the Province, appear to have affected base-load coal generation prices in the MISO market region.

MH's export price forecasts assume that GHG legislation will come into play as early as 2012, and boost export prices. The Board is concerned with this degree of optimism, with $18 billion of capital expenditures lying in the future; 'best case" scenarios, while interesting and useful as goals, need to be balanced by other less positive views. The Board will direct MH to revisit its export pricing forecasts to reflect recent realities on market prices and exchange rates.

On a similar vein, MH has indicated that embedded costs incorporate substantial levels of mitigation efforts and costs. By capitalizing these costs, MH is deferring the impacts on the COSS, and on rates. The Board is mindful of the possible effects to arise out of the adoption of IFRS, and that one of those effects may well be less capitalization and more direct allocation and expensing of period costs; if this occurs, it means either less annual net income or it will require higher rate increases.

The foregoing suggests explicit consideration of environmental factors is either not necessary, or that to do so would be a form of double-counting. This issue needs further definition and development.

14.0 Rate Design

14.1 Inverted Rates

In Order 117/06, the Board reiterated its directive to MH to move towards the elimination of declining block rates. MH has, with some notable exceptions, moved toward this objective.

MH introduced, on a very limited scale, an inverted rate structure for the residential class, where the tale block rate is to be greater than the first block by a modest 1% differential. MH has suggested a continued future GRA movement in the direction of marginal cost, through future gradual increases in the to the tale block closer to the marginal cost of energy (now 7.01¢/kW.h.).

MH proposed that the first block of energy consumption be set at 900 kW.h per month, regardless of the season or the energy source for residential space heating. MH did not propose any changes to the basic monthly charge block rate.

MH acknowledged that the future evolution of the inverted residential rate should take into consideration the needs and constraints of customers who currently use electricity as a primary heating fuel, while continuing to encourage natural gas as the appropriate fuel choice in areas of the province served by natural gas. MH indicated that to address heating loads, there are essentially three approaches that could be taken to provide for meeting these needs within a lower cost first block.

The more complex mechanism would be to design a separate residential rate for electric heating loads. MH stated that this is the method preferred by Mr. Chernick, the witness for RCM/TREE, and would provide existing electricity heating customers an allowance of an additional 6,400 GW.h/ year in the initial price block during the heating season. This would result in an increase in the percentage of heating energy served at the initial rate block of roughly 54% that non-electric heating customers receive.

MH cautioned that such a specific rate targeted at electric heat customers may create an incentive for customers to report electric heat capability though staying with natural gas, and may create increased administrative burden and cost to manage/police.

MH offered two alternatives that may be simpler to administer, and which may not specifically target all electric heat customers or exclude customers using other sources of heating. MH noted the simplest method would be to differentiate the size of the first block by season, with a larger first block in winter, as is done in Ontario. The other is to provide a larger first block in winter only in areas not served by natural gas (although this may be complicated by the uniform rates legislation). MH concluded that further review of the alternatives were required.

Given the significance of residential electric heat in Manitoba (natural gas distribution is limited), as well as higher degree-days compared to Ontario, the Board would consider it appropriate to set a winter “first block size” higher than that now set in Ontario.

14.2 General Service Small and Medium Classes (GSS and GSM)

MH is moving to consolidate the GSS and GSM rate structures, supported by previous Board direction. Both classes are served from MH-owned transformation and utilize similar voltages.

The following rate table illustrates the proposed changes as initially proposed by MH (1) and the revised rates (2) as per Order 90/08 as follows:

	Small			**Medium**		
	March 2007	**April 2008**		**March 2007**	**April 2008**	
		1	**2**		**1**	**2**
Basic Charge Single Phase	$15.60	$16.50	N/C			
Basic Charge Three Phase	$21.75	$23.55	$22.99	$27.60	$27.60	N/C
Energy Charge:						
1st 11,000 kW.h	6.18¢	6.31¢	6.48¢	all kW.h	5.90¢	6.13¢
Next 8,500 kW.h	4.00¢	4.30¢	N/C	@	4.07¢	4.30¢
Balance kW.h	2.55¢	2.65¢	2.73¢	2.55	2.65¢	2.73¢
					no charge	
Demand Charge:						
1st 50 Kva	no charge	No charge		all KVA @		
Balance of KVa	$8.34	$8.34	N/C	$8.34	$8.34	N/C

The proposed changes are the first step of two or three transitional moves to a single rate table for GSS and GSM.

A major rate component that currently differentiates the small and medium rate classes is the application of demand ratchets, which impact the determination of monthly billing demand. The general service small class is not subject to any ratchet provisions and the class' customers are only billed on their recorded demand above 50KVa. General service medium customers are, on the other hand, currently subject to paying the higher of their recorded demand or the ratchet.

Once the classes are fully consolidated, the ratchet would not impact current general service small customers as long as they remain below 200 KVa. In MH's Application, it did not propose that the 70% winter ratchet provision be modified, but that it would continue to be applied against loads in excess of 200 KVa.

14.3 Area and Roadway Lighting (ARL)

MH has proposed a 1% increase in the ARL rate.

City of Winnipeg raised its continuing claim of the overpayment by municipal lighting customers relative to costs being allocated to the class in the embedded cost COSS. As this class has almost always been charged more than 105% of its allocated costs, MH did not dispute the City of Winnipeg's suggestion that the accumulated sum of "overpayments", relative to an RCC of unity, totals in the multi-million dollars. The City of Winnipeg did not request a refund, but rather suggested that ARL rates remain unchanged until a RCC of 1.00 is achieved.

14.4 Time of Use (TOU) Rates

Over the last eight years, the concept of Time of Use energy charges has been a subject of debate. MH has commissioned several studies to address the applicability and consequences of charging customers different seasonal and/or diurnal energy rates.

The major stumbling block has been, and continues to be, the need for more sophisticated and expensive metering and billing systems (an investment of $90 million was suggested as being required). At present, most GSL >30 customers have appropriate metering in place, however, that is not the case for GSL <30, GSM, GSM, and Residential classes.

MH has and is currently running pilot studies in Selkirk and Steinbach, to test customer response to greater awareness of actual consumption levels; the results to-date have been somewhat confusing, and have failed to give support to a massive move to TOU for residential customers.

MH acknowledged that, on balance, a TOU rate for General Service customers would likely provide increased revenues for the Corporation. MH indicated that such a TOU program could take about 12 - 18 months for start-up studies and to obtain program approval for classes with TOU meters. And that implementation could take at least four more years for the classes currently without TOU meters.

For the residential class in particular, a TOU program would involve changes to meter reading frequency. While new technologies are possible, it would appear costs could be prohibitive.

14.5 Rebalancing of Demand and Energy Charges

MH's rate structure has for many years been over-collecting on demand charges and under-collecting on energy charges relative to COSS allocations. In response to Board direction, MH has, since 2003, been assigning rate increases entirely to the energy portion of rates.

The result has been a gradual shift of the source of customer revenues, with the change viewed as being conducive to be objectives of conservation.

The following table illustrates the March 2007 imbalance situation, when comparing PCOSS-08 allocated costs to revenue at March 2007 rates.

	Demand ($/KVA)			Energy (¢/kW.h)		
	March 7/07 Rate Revenue	**117/06 Allocated Cost**	**Revenue/ Cost %**	**March 7/07 Rate Revenue**	**117/06 Allocated Cost**	**Revenue/ Cost %**
GSS	8.34	6.92	120	2.55	2.65	96%
GSM	8.34	7.09	118	2.55	2.68	96%
GSL <30	7.08	7.94	89	2.38	2.61	91%
GSL 30-100	6.06	4.26	142	2.29	2.44	94%
GSL >100	5.40	2.21	244	2.26	2.41	94%

The table suggests that MH still has a considerable way to go before revenues and costs for GSL demand and energy are in balance. Of particular note is that GSL <30 KV class revenues and rates are under-collecting for both energy and demand.

MH's March 2007 Report suggests that over a four-year period, the movement toward "full balance" has eliminated 50% of the initial discrepancy. This infers it could require another four years of rate increases applied through energy changes alone to achieve balance.

For GSS and GSM customers, the demand charge partially offset the under-funded basic monthly charge for customer service and distribution plant.

14.6 The Basic Monthly Charge

All MH customers other than GSL pay a basic monthly charge, which is intended to cover (but does not) allocated customer service and local distribution costs.

	Billing Rate	**Allocated Unit Cost (Net of Export Credit)**
Residential:		
- (<200 amp)	$6.24/month	$18.70/month
- (>200 amp)	$12.48/month	
GSS-ND	$16.50/month	$31.25/month
GSS-D	$23.55/month	$51.22/month
GSM	$27.60/month	$227.78/month

The argument for not increasing the basic monthly charge is based on the premise that the under-charge is justified by the “incentive provided” in high energy charges to reduce consumption.

14.7 Diesel Rates

At one time, in excess of thirty northern Manitoba communities were provided electricity service by means of diesel-fired generation. Over time, the number of communities served by diesel generation fell, at first to thirteen and, eventually, to the now current four.

The remote Northern Manitoba Communities of Shamattawa, Tadoule Lake, Brochet and Lac Brochet, with a total population of approximately 2,000 people having 800 separate accounts with the Corporation, are not connected to MH’s transmission and distribution grid. While diesel fuel is very expensive, there are other problems with diesel generation such as winter road supply uncertainties, customer service levels and environmental issues.

Diesel generation does not provide the quality of service represented by grid service, as the four diesel class communities are limited to 60 amp service and the 800 accounts are not supposed to use electricity service for space heating.

In Manitoba, the first 2,000 kW.h of electricity consumed monthly by residential and General Service customers in the diesel zone is billed at grid comparable rates. The subsidy from full cost rates is borne by “Government Accounts” by way of surcharges or premiums. In some other Northern Canadian jurisdictions, less than 900 kW.h of diesel generated electricity is provided at grid comparable rates.

Excepting for the first 2,000 kW.h of electricity, diesel class rates are very much more expensive than grid rates. Most diesel class customers are residential, but there are also General Service, Federal and Provincial Government and First Nations accounts.

In Order 159/04, dated December 22, 2004, the Board approved interim sales rates for the diesel communities based on MH’s then-Application, which reflected a tentative settlement arising out of MH’s negotiations with MKO, acting on behalf of the diesel communities, and Indian and Northern Affairs Canada (INAC).

The terms of the tentative settlement were summarized in Order 159/04 to include:

1. MH would request Board approval for an allocation of net electricity export revenues to first retire the diesel zone accumulated deficit which was approximately $16.9 M as of March 31, 2004. Once the deficit had been recovered, the net export revenue would be used to reduce costs allocated to the diesel-zone customer class, thus reducing the otherwise rate requirement;

2. INAC would pay $3.2 million to MH for the surcharge billed to INAC by MH between November 2000 and May 2004;
3. INAC, on behalf of the Federal Government, would pay MH 69% of the $28.8 million of MH's diesel-related capital cost, the balance as at March 31, 2004, by July 7, 2005 without interest and by no later than January 7, 2006;
4. MH would request that other Federal and Provincial Government customers in the diesel zone (notably Health Canada, the RCMP, and the Province of Manitoba), pay MH a further 10% of MH's $28.8 million of undepreciated capital costs;
5. MH would assume the remaining 21% of undepreciated capital costs on behalf of residential and General Service customers that are neither First Nations members nor Government accounts; and
6. for major future capital expenditures in the diesel zone, MH would consult with the diesel zone's First Nations communities, and secure funding prior to making further capital expenditures.

At the time of issuing Order 159/04 the Board was advised that the signing of the Settlement Agreement was expected on or before July 7, 2005 – now three years ago. Because of various factors, the signing date has been delayed.

If the Settlement Agreement is not concluded, MH has indicated a desire to reconsider its recommendation that the class receive an allocation of net export revenue in the COSS. The delay in the finalization of the Settlement Agreement relates to the Federal Government and is beyond the control of the Board, MH, the four communities served by diesel-fired generation and the Province.

14.8 Surplus Energy Program (SEP)

MH was earlier provided with interim approval to extend the Surplus Energy Program to October 31, 2008. As part of the GRA process, MH requested that SEP be approved for five years to March 31, 2013, without any changes to the terms and conditions.

The SEP makes surplus energy available on an interruptible basis to MH's general service customers. Customers may be eligible for:

Option #1 Industrial load >1,000 KVA monthly demand (<25% of total load); or

Option #2 Space and/or water heating >200 KW per month (separately metered with full back-up); or

Option #3 Self generation displacement 200 KW to 50,000 KW with Load Factor of 25% (separately metered with full on-site back-up).

The program primarily displaces export sales, but the energy supplied to SEP customers may be supplemented from import supplies, though at much higher costs than domestically supplied energy. Energy prices (Spot Market) are forecast weekly and submitted for Board approval, for peak, shoulder, and off-peak prices.

Since December 2000, SEP has involved about 25 GSM and six GSL customers, with average (over seven years) sales of about 22 GW.h/year, average revenues of $9 million (4¢/kW.h) and average net revenues of $45,000/year (varying from a loss of $35,000 to a surplus of $210,000/year).

The customer usage of the SEP has been seasonally variable, with winter weekly high consumption being ten times summer weekly low consumption. Over the whole year, the daily usage pattern has been 24% peak, 40% shoulder, and 36%

off-peak. Demands during the summer off-peak when prices are low have been well below average.

14.9 Curtailable Rate Program (CRP)

The Curtailable Rates Program provides incentives to MH's large industrial customers; these customers curtail electrical load when called upon by MH. Incentives are provided by way of a credit to the customer's monthly energy bill.

Under the CRP, MH looks to:

- Quickly re-establish contingency reserves that are required by MAPP-GRSP;
- Maintain planning reserve obligations;
- Protect firm Manitoba load from curtailment;
- Maintain spinning and non-spinning contingency reserves; and
- Meet firm energy requirements when MH has supply shortfall.

Different CRP options provide MH with the ability to curtail demand and energy for specified time periods. Customers are provided with power price discounts on the basis of the amount of load available for curtailment. The Board approves the reference discount on an annual basis.

Savings to MH resulting from the Curtailable Rates Program are available as long as the service offering continues, whether or not actual curtailments are made at the time of system peak or at any other time. The expected availability of this load, and not the timing of its dispatch, determines the future benefits of CRP.

MH requested a change to the terms and conditions of CRP, to increase the notice period from 24 to 48 hours of anticipated plant operations shut down. This would affect the capacity reduction that could be achieved by MH.

14.10 Limited Use Billing Demand (LUBD)

The LUBD rate option was implemented July 1, 2000 and continues to be a relatively simple way for MH to address the concerns of low load factor customers and reduce demand charges they would otherwise face. Initially, the program was intended to mitigate the impact of the winter ratchet on seasonal, commercial, and light industrial winter operations. However, the program has attracted a considerable number of GS customers who are not affected by the winter ratchet. Only 5 of 123 GS customers were subject to the winter ratchet in 2004.

Currently, the customer list on LUBD is:

GSS-D -	68 (winter ratchet not applicable)
GSM -	22
GSL <30	17
GSL >100 -	1
	123

LUBD allows eligible customers to opt for higher energy rates and lower demand charges. For customers with a load factor of 18% or less, the revised rates are economically beneficial. The rate has turned out to be attractive to certain agricultural, recreational, municipal services, and wood product customers, which now account for 40% of the customers utilizing the program.

From MH's point of view, LUBD customers with their low load factor generally have lower coincident system peaks. As such, they place a lesser demand on system transmission and distribution.

MH did not propose to alter the LUBD rate structure as it applies to GSS-D and GSM, but sought to revise the eligibility requirement from 36 months to 12 months.

14.11 Winter Ratchet

The winter ratchet refers to MH's demand billing practice of charging customers the greater of:

- Actual billing demand (KVA) in each month (measured on 15 minute interval); or
- 70% of highest demand in any previous months of December, January, and February; or
- 25% of the customer's contract demand; or
- 25% of the highest measured demand in any of the previous 12 months.

The rate is applicable to GSS-Demand/GSM, and GSL classes and particularly affects seasonal customers that have high winter demand and minimal summer demand. These customers have contended that MH was charging them a demand charge related to energy that they were not using and was thus available for export by MH.

MH contends that the energy freed up is unreliable and not always of value, and recent history suggests that the energy probably has similar value to DSM freed-up energy.

The winter ratchet impacted about 700 customers in 2004, primarily in the GSM class, generating about $2 M in billing revenue. Notably, schools, hospitals, senior's residences, and similar facilities are included in this class.

The Board found that with MH's system running at near capacity throughout the year, the winter ratchet was of questionable merit and, in Board Order 07/03, directed MH to eliminate the winter ratchet effective April 1, 2004. MH sought and was granted (Board Order 15/03) a deferral to allow further study. An August 2004 report by MH argued for the retention of the winter ratchet pending further review. MH suggested that time-of-use rates may be an alternative to the winter ratchet.

Since 2004, the situation has remained essentially unchanged. MH is still considering the preparation of a time-of-use study and has not advanced a detailed analysis supporting the retention of the winter ratchet.

14.12 Interveners' Positions

The City of Winnipeg

The City of Winnipeg indicated that the rates charged the city for area and roadway lighting have been consistently above the zone of reasonableness (over the last 30 years, with the exception of one year). The City indicated that over the years MH has overcharged it approximately $49 million.

The City noted that MH proposes to address the "$620,000 excess" the City is now paying each year, or the $1 million "over collected" province wide (other municipal accounts approximate 40% of the annual bills to the class).

The City urged Board action to correct the situation.

The Coalition

Inverted Rates

The Coalition stated they are supportive of the concept of inverted rates but that for the intervener significant equity concerns exist; concerns for the impact of all-electrical customer with no competitive options; concerns for low-income persons who lack the resources to pursue DSM; and concerns for renters who may lack the ability to pursue DSM or for whom energy efficiency is uneconomic due to split incentives.

The Coalition stated that most new homes in rural areas are installing electric water and space heat, and that many of the new all-electric homes are being built in First Nation communities (many of which being low-income households). The Coalition noted that many customers with all- electric homes don't have access to competitive alternatives such as natural gas, and would not be able to adjust consumption with changes in prices and would be negatively impacted by an inverted rate scheme.

The Coalition opined that residential consumers have an inelastic demand for electricity, which means a change in consumer demand should be expected to be less responsive to a change in price. The Coalition cited a study by the Rand Corporation that dealt with electricity consumption in the US, which stated:

> "Locations where particular energy uses are very valuable, such as air conditioning in southern states or winter heating in northern states, could have price elasticity smaller in absolute magnitude because air conditioning and heating are so valuable during periods of extreme climate. The consumers are unwilling to change their use when prices change."

The Coalition underscored the importance of price signals, indicating that, in particular, commercial and industrial customers were more responsive to changes in price in adjusting their consumption.

The Coalition further suggested that there is a low-income context that needs to be addressed related to inverted rates. The Coalition suggested that MH currently has over 18,000 customers earning less than $30,000 a year that are consuming more than 18,000 kW.h per year, of which over 16,000 of those customers are all-electric customers.

The Coalition noted that this group would be negatively impacted by an inverted rates scheme, that is unless the current barriers to participation in energy efficiency DSM programs are addressed. The Coalition stated there are substantial barriers faced by low-income individuals that discourage their participation in energy savings initiatives.

Mr. Harper noted that the inverted rated proposal put forward by MH has a modest differential between the first and the second blocks, but that the modest differential does at least begin to send the correct message, i.e., that increased use is more expensive. Mr. Harper further stated the issue of bill impacts is important and should be addressed before MH makes further changes in implementing inverted rates.

Mr. Harper proposed a gradual implementation of inverted rates, and proposed that before any further changes are made MH should first ensure that its DSM programs are focused in fully supporting those low-income customers who will be most notably impacted by inverted rates, and customers who typically use more than 1,500 kilowatt hours a month (over 18,000 kW.h annually).

The Coalition stated that it would be unfair to implement inverted rates before giving vulnerable groups the tools to achieve energy efficiency. The Coalition recommended delaying inverted rates until adequate DSM programs are in place for low-income households with high consumption levels, tenants, and all-electric space heat customers that have no competitive space-heating options.

To address the inequity faced by all-electric customers, the Coalition suggested the focus should be on the differentiation between the all-electric block and the standard-use block, providing the all-electric block a larger first block during the heating season. From its perspective, the key issue is addressing the vulnerability of those customers who rely upon electric heat for their home heating.

Time of Use Rates

The Coalition expressed interest in advanced metering technology, which would be required to implement time of use rates. The Coalition urged the Board to direct MH to report on developments in terms of such metering, including the potential for the Utility controlling thermostats for peak shaving purposes.

Energy Demand Rebalancing /Basic Monthly Charge

Coalition opined there should be no increase in the BMC and suggested that the cost allocation process be changed for residential customers.

As well, the Coalition recommended the BMC recover only a percentage of customer costs, excluding customer related distribution costs, and recover only in part customer service and metering costs, with the balance of costs to be recovered through energy charges

MIPUG

Inverted Rates

MIPUG suggested that MH's inverted rate proposal for the Residential Class was inadequate, and that the small differential would not send a meaningful price signal to customers.

MIPUG suggested that MH implement inverted rate proposals for other customer classes, including the General Service large class and sub-classes. MIPUG recommended the Board direct MH to develop an inverted rate proposal for the General Service large class, in consultation with customers, and file it with the Board for consideration.

Time of Use Rates

MIPUG recommended MH be directed to develop seasonal time-of-use rates. Mr. Bowman and Mr. McLaren stated that for customers with some ability to shift their loads, a rate design that includes time-of-use components could reduce MH's costs and that these cost savings could flow, at least in part, to the load-shifting customer. For MIPUG, properly designed time-of-use rates would provide incentives to optimize the use of the generation and transmission system, resulting in cost savings and/or increased export revenues to the mutual benefit of MH and its customers.

MIPUG stated that TOU rates meet a valid regulatory objective of promoting efficiency and conservation and would provide customers the right price signal for every kilowatt hour of consumption. MIPUG stated that such an approach would be an improvement over the winter ratchet, which, for MIPUG, sends too strong a price signal for some, and none to others.

Energy Demand Rebalancing /Basic Monthly Charge

MIPUG noted that MH sought applying the Industrial rate change entirely to the energy component (and not the demand component). Given the substantial outstanding issues arising from the lack of contemporary pricing mechanisms, MH's efforts at improving the price signal were, for MIPUG, effectively irrelevant and should be rejected.

MIPUG recommended the Board reject the proposed allocation and direct MH to propose a logical process for implementing, in consultation with customers, rates that address contemporary elements of industrial rate design. In the meantime, any rate increases for industrial customers should be implemented as an equal percentage increase to the demand and energy components of the existing rate structure.

MIPUG did not take a position on whether any changes should be made to the BMC.

Winter Ratchet

MIPUG recommended the elimination of the Winter Ratchet, with it to be replaced by time of use seasonal rates.

MKO

Inverted Rates

MKO stated general support for the concept of inverted rate structures, to encourage demand and improved energy management. However, MKO shared the concerns expressed by the Coalition that inverted rates for residential customers may disadvantage consumers with electric water and space heating - customers that include MKO consumers, most of which were reported to be of low income.

MKO also noted the inelastic demand response residential customers have to electricity price changes, as noted in studies referenced by the Coalition. MKO supported the Coalition’s comments on addressing the barriers to entry to DSM measures noted by Mr. Dunsky, and supported making DSM and energy efficiently programs universally available to all MH residential customers, including those in the diesel communities. MKO suggested that DSM in the diesel zone would likely have a greater impact on reducing domestic demand growth and providing for increased net export revenues than inverted rates for residential customers.

MKO proposed a more gradual inverted rate be applied to the diesel communities, and suggested such an approach may accomplish the objectives of MH without the controversy that would be inherent in trying to set and administer baselines.

MKO cautioned the Board that the inverted rate design proposed by RCM/TREE requires further testing and review to ensure that low-income and remote community MKO customers are not unduly disadvantaged.

MKO suggested the Board direct MH to propose inverted rates structures in the next GRA across all customer classes.

Basic Monthly Charge

MKO did not provide a position on changes to the BMC.

RCM/TREE

Inverted Rates

RCM/TREE recommended changes to the inverted rates program as proposed by MH, and suggested that the BMC be reduced to approximately $4.70 per month and the first block of energy be reduced from the 900 kW.h per month allowance to 600 kW.h.

RCM/TREE suggested that the rate for the initial energy block should be set at 6¢ per kW.h for 600 kilowatt hours per month for non-heating customers, and for all customers in non-winter months. In addition, to counter the impact of the inverted rates on all-electric customers, RCM/TREE proposed a 6,400 kilowatt hour annual allowance be distributed over the heating season, and be priced at the initial block rate.

RCM/TREE proposed that the rate for additional energy should be set at approximately 6.28¢ per kilowatt hour.

RCM/TREE discounted MH's concerns about the accuracy of the Corporation's customer database for identifying customers with electric heat capability, and suggested that exceptional cases and administrative gaps should not obstruct sound policies. RCM/TREE stated it advocates an integrated approach to affordability and efficiency.

Paul Chernick, a witness for RCM/TREE, stated inverted rates are a good and sound economic policy, and observed that while there are low-income customers that would be affected by the implementation of inverted rates that should not act as a "veto" for the program's implementation.

Mr. Chernick stated proper steps to protect lower income individuals should be put in place. Mr. Chernick proposed the implementation of targeted low-income conservation programs and bill assistance, the latter through vouchers, as mitigation measures, enabling the Corporation to move more quickly to implement conservation measures. "There is no time for the extreme gradualism advocated by Mr. Harper", according to Mr. Chernick.

RCM/TREE stated that if MH requires time to prepare education materials and mitigation measures with respect to the introduction of inverted rates, it might be possible to begin introduction by residential rate increases under a flat rate structure, and then implement a revenue neutral inverted rate structure in the fall.

RCM/TREE did not agree with the Coalition that gradualism in the implementation of inverted rates is a good idea.

Energy Demand Rebalancing/ Basic Monthly Charge

RCM/TREE proposed the elimination of the BMC over time, and the recovering of those costs through volumetric energy charges to be applied on the tail block of inverted rates.

RCM/TREE countered concerns raised by MH that lowering the BMC for electric customers might encourage customers with small gas usage to switch to all electric appliances to avoid the recently increased gas BMC. However, RCM/TREE noted, since gas customers are also electric customers, such an incentive to switch is already built into the BMC for small users of gas. Lowering the BMC for electric customers and increasing the tail block rate provides a counter incentive for that move, according to RCM/TREE.

RCM/TREE also countered concerns raised by MH that suggested that because customer-related costs are real costs, larger consumers of energy will subsidize costs of smaller energy consumers. RCM/TREE noted that all customers are subsidized from export profits, and that credits applied to the BMC rather than energy would be a more equitable approach, and also provide a stronger price signal to conserve.

Time of Use Rates (TOU) & Demand Ratchets

RCM/TREE recommended MH should implement TOU rates, starting with the largest customers, and move revenue collection from demand charges to time-of-use energy charges. RCM/TREE acknowledged that time of use rates will require appropriate metering, but held that they should be implemented as soon as feasible. The intervener also recommended that MH eliminate demand ratchets.

Mr. Chernick noted that in jurisdictions where TOU rates have been implemented a parallel billing system was utilized, where a customer would, along with the existing bill, receive a bill as if they were on time of use rates. This allowed the customer to gauge the impact the TOU system had on their consumption and billing, and allow them time to make changes in energy use behaviour.

14.13 Board Findings

Inverted Rates

The Board encourages MH to develop plans to employ an inverted rate structure for all customer classes, initially to be designed on a revenue neutral (to MH) basis and to send a “price signal” for every kilowatt hour of energy used, to promote conservation.

MH suggested that too large an inversion would be prejudicial to all-electric customers. However, the nominal inversion of the Residential Rate approved by Order 90/08 can be expected to cost an all-electric customer approximately $45/year.

In comparison, a natural gas space-heated home, with a conventional furnace, can expect to pay hundreds of dollars more for space heating this upcoming winter as compared to a similarly adequately-insulated, electrically-heated home.

The Board agrees with the principle of inverted rates but notes, based on demand studies presented, that residential customers, in particular, do not significantly change their consumption patterns upon a price increase.

The Board shares the concerns expressed by all parties on the impact that sharply inverted rates would have on both low-income customers and all all-electric heat-load customers, who are unlikely to diminish consumption with increases in electricity prices. So, if the inversion were to be sharper, to promote conservation, this could be expected to result in a relatively high proportion of consumption being exposed to the higher second-block rate.

The Board notes that (with respect to the identified problem which electric heat customers could incur with sharply-inverted rates) there are methods to address what could be considered the inequity that could result from such sharply-inverted rates. The Board is aware of the complexities that MH will face in addressing this concern, but it warrants a fulsome analysis.

In particular, the Board is interested in MH providing additional information on seasonal variations in the size of the first electric block for electric heat-load customers. The Board agrees with MH that the size of the first rate block for Manitoba, as compared to the one utilized in Ontario, will likely have to be higher to take into consideration the greater heating load factor due to Manitoba's colder winters. The Board will direct MH to file a plan by January 15, 2009 outlining the pros and cons of the various potential inverted rate strategies under consideration, and the MH-proposed course of action to address this issue.

The Board is quite concerned with the impact that sharply-inverted rates will have on low-income customers. The Board shares the concerns raised by the Coalition that barriers exist that preclude low-income customers from taking actions to reduce electricity consumption. Given that the proposal currently under consideration only reflects a nominal differential between the first and second block, the implementation of inverted rates should not be delayed, and the Board will address the problems of higher energy costs for low-income households in a broader way.

Nonetheless, the Board will expect MH to put forward more comprehensive plans to shield low-income customers from the impacts that will result from higher electricity rates in a sharply-inverted rate scheme.

With respect to the level of the basic monthly charge, the Board will direct MH to increase the Basic Monthly Charge by 5% on July 1, 2008 and a further 5% on April 1, 2009, by way of Order 90/08. The increases will result in BMCs that will still be well below a representation of MH’s actual customer-based costs.

MH is to continue with the process of the GSS and GSM customer class consolidation, and provide the Board with a proposal by June 30, 2009 for a stepped-up program and a timeframe for completion.

Time of Use (TOU) Rates should be fast-tracked for customer classes where the required meter technology is currently installed. TOU rates assist in defining marginal cost, and therefore, should be included in any new proposed energy-intensive industry rate for consideration by the Board.

The Board will direct MH to provide a planned implementation strategy outline by September 30, 2008 for TOU rates, as appropriate to the classes with required metering technology already in place. Alternate rate strategies should be included for consideration at the upcoming Energy Intensive Industry rate hearing.

Energy and demand balancing is a policy issue that speaks to the fairness of rates to individual customers within a class. The argument for reducing demand charges, and increasing energy charges, is that it does send an improved price signal and thus promotes conservation. As the change occurs, Demand and Energy Cost recoveries will be brought more into line with cost causation principles. The Board will therefore direct MH to plan to re-balance demand and energy charges on a revenue-neutral basis, and submit a 5-year transition plan for the Board's approval at the earlier of December 31, 2009 or the next GRA.

Diesel Zone: MH has indicated it will apply to the Board for finalization of the 4 interim Orders related to Diesel Rates. In such an application, the Board will also direct that MH provide reports on:

a) the fairness of the rate approach with respect to non-senior government accounts (the Board is concerned that the rates restrict the economic development prospects for the communities and drive up service and commodity costs);

b) the efficacy of the current rate schedule for non-government accounts (data on aged accounts receivable, delinquency and bad debts together with the collection policies in place for the four communities will be required);

c) the effects of the current approach to rates and consumption restrictions on the four communities, a detailed review of consumption levels and collection practice from the former Diesel communities that have been connected to the Grid which will serve as a comparison; and

d) MH to report to the Board by September 1, 2008, as to the balances and status of the diesel zone accounts; to ascertain whether existing interim rates are fully recovering operational costs.

Area and Roadway Lighting (ARL)

The Board agreed with the position advanced by the City of Winnipeg and, by Order 90/08, did not approve any rate increase for the Area and Roadway Lighting class for either July 1, 2008 or April 1, 2009.

SEP

The Board is concerned with MH's marketing practices that yield extremely low prices for off-peak exports, and suggests that retaining energy in storage may prove more beneficial in the longer term than selling power for extremely low prices. The Board acknowledges that MH may be operating the system at near optimal levels to avoid "spilling" water, but there may be a benefit to spilling when prices get too low.

MH will be directed to provide a report to the Board by January 15, 2009 evaluating the Surplus Energy Program; the report should employ monthly historical data from 2000 to 2008 to analyze and compare the benefits and costs of the actual operation of the hydraulic generating system pursuant to various less aggressive sales strategies. This report should address the relative merits of withholding surplus energy from sales at off-peak periods.

The report may show whether selling at any cost increased the financial losses in 2003/04; and may also have resulted in foregone opportunity exports in 2004/05 because of low energy in storage.

In the interim, and by Order 90/08, the Board approved the extension of the SEP until October 31, 2008, on the condition that annual reports will continue to be provided.

The Board also approved all weekly interim SEP Orders, from August 1, 2007 (Order 100/07) through and including May 21, 2008 (Order 61/08), by way of Order 90/08.

CRP

Having heard no opposition to the request, the Board approved the requested change in the Terms and Conditions for the CRP by way of Order 90/08, with annual reports to be provided as previously.

LUBD

By Order 90/08, the Board also granted final approval of the revisions to the Terms and Conditions of LUBD, reducing the eligibility requirement from 36 months to 12 months. This revision will provide customers with increased flexibility to opt out and into the LUBD option, with minimal financial impact on MH or other participating ratepayers. The Board will, however, require annual reports on this program to illustrate the economic impact on MH and customers.

Winter Ratchet

The winter ratchet should be eliminated, such that customers are billed actual demand. With MH's summer and winter demands being nearly equal, there is not a strong case for retention of the ratchet. The ratchet does not send a strong price signal and is a source of considerable customer complaint. The ratchet can be removed with only a negative $2 million a year financial impact. Unless MH provides an acceptable TOU implementation process, the ratchet is to be removed ahead of the winter of 2009/10, and the change will be confirmed in an Order to follow in due course with respect to the conditional rate increase for April 1, 2009.

As previously mentioned, MH should file an implementation program for TOU rates for GSL customers with a fast-tracking of the subclasses that have the necessary metering technology in place.

It is currently the Board's intention to direct the elimination of the winter ratchet by September 30, 2009; the matter will be addressed in the Order related to the conditional April 30, 2009 rate increases.

15.0 Class Rate Impacts

15.1 Rate Changes/Rate Impacts

MH increases as of July 1, 2008 approved in Order 90/08 were::

	2008/09	**Range of Bill Impacts**	
Class		Low	High
Residential	5.06%	3.8%	5.52%
General Service Small Non-Demand	5.08%	4.88%	5.08%
General Service Small Demand	4.83%	3.98%	6.10%
General Service Medium	5.01%	3.22%	5.53%
General Service Large <30 kW	5.16%	3.35%	6.27%
General Service Large 30-100 kV	5.04%	3.21%	5.77%
General Service Large >100 kV	5.07%	3.07%	5.33%
Area and Roadway Lighting	0.0%	-	-
Overall General Service	4.95%		

Based on the approved July 1, 2008 rates, residential customers will experience increases ranging from 3.8% to 5.5%, depending on monthly consumption. Customers using more energy will experience higher than average increases.

For example, a typical residential customer without electric space heat consumes approximately 1,000 kW.h per month on average and will note an increase in their monthly bill of $3.03 or 4.7%. A residential customer with electric space heat, using on average 2,000 kW.h per month, will note an increase of $6.36 or 5.2% per month.

General Service Small commercial customers will experience increases ranging from 3.98% to 6.10% depending on monthly consumption and/or load factor; the overall class average increase is 4.94%.

General Service medium: commercial/industrial customers will experience rate increases ranging from 3.22% to 5.53%, depending on monthly consumption and/or load factor; the overall class average increase is 5.01%.

Increases to General Service large customers vary depending on the voltage level served and the load factor of each customer. MH proposed that the demand charge applied to the General Service large classes remain the same with only the baseline energy charge to increase. This charge results in higher load factor customers receiving a higher percentage increase.

For rates effective July 1, 2008, customers served at 750 V – 30 kV will have increases in their monthly bills ranging from 3.35% to 6.27%, with the average increase being 5.16%. Customers served at 30 kV to 100 kV will experience increases ranging from 3.21% to 5.77% with the average being 5.04%. General Service large customers served at over 100 kV will note increases ranging from 3.07% to 5.33% per month, with the average being 5.07%.

15.2 Differential Rate Increases

MH did not propose any class differential rate changes in its application other than for ARL, as it was MH's position that the current COSS has not been sufficiently tested to justify relying solely on the RCC results indicated therein. Furthermore, MH noted that the Board had not given MH any indication as to how marginal cost and environmental considerations will be reflected in Rate Design.

15.3 Interveners' Positions

RCM/TREE suggested that only marginal costs be considered in Rate Design, while the Coalition took the position that while the COSS should be the primary basis for rate setting, marginal cost should also be considered.

MIPUG took the position that the COSS has been adequately vetted to allow it to be established as essentially the entire basis for rate setting. MIPUG strongly supports the concept of moving RCCs to unity over five years, and suggested that a five year migration based on a 2.9% annual rates increase would bring about annual rate increases of:

- Residential 3.78%
- GSS-ND 1.92%
- GSS-D 1.26%
- GSM 2.65%
- GSL <30 5.36%
- GSL 30/100 2.04%
- GSL >30 0.93%
- ARL 1.31%

15.4 Board Findings

The Board has accepted MH's proposal for across-the-Board increases for 2008/09 and 2009/10, in order to allow further consideration of marginal cost factors for subsequent GRA's, and, by Order 90/08, directed a 5% across-the-board increase for all customer classes except for Area and Roadway Lighting, which is to receive no increase.

Also, by Order 90/08, the Board has indicated, on a conditional basis, subject to a number of reports to be required of MH, a further 4% across-the-board increase as of April 1, 2009, except for Area and Roadway Lighting which is to receive no increase.

16.0 Energy Intensive Industry Rate (EIIR)

16.1 Background

In the public hearing that resulted in Board Order 117/06, MH raised a concern related to energy consumption by energy-intensive firms, using energy as a manufacturing input. MH foresees its revenue position and the rates of other customer classes as being threatened by new or expanding industrial loads.

MH outlined its concern by considering its energy sales to energy intensive industrial customers, typically earning the Utility approximately 3.2 cents per kW.h while energy to secure such new or expanding load may be diverted from profitable export markets, which MH forecasts to return approximately 5.39 cents per kW.h. MH's example was a new or expanded load of, say, 100 MW causing a reduction of up to $18,000,000.00 per year in MH's net income, which would, according to MH, likely necessitate a rate increase of approximately 1.8% to all domestic customers served by the Utility (to recover such a revenue deficiency).

The issue compounds in the longer term, when MH assumes the risks of advancing construction of a major new generating station to meet new industrial load at prices below marginal costs. The decision that lies ahead following MH's refiling of its application potentially has large economic consequences.

While identifying the problem is relatively straight forward, the solution(s) is/are more elusive.

Against that background, the Board notes that it provided direction in Order 117/06, including that:

- MH to consult broadly, and in particular with government and industry, prior to advancing a proposal;

- MH to develop its proposal taking into account that existing industry came, remained and expanded in Manitoba with certain assumptions as to energy prices and supply – and therefore a distinction between new and existing industry is reasonable; and
- MH to provide a report and recommendations with respect to establishing a new energy – intensive industry class, including criteria developed after broad consultations with industry and government, and rate design recommendation.

16.2 MH'S Proposal

In its GRA, and in response to Order 117/06, MH proposed a new General Service Large rate schedule that would limit the application of "heritage" energy rates (based on embedded costs) to industrial customers specific baseline energy quantities per year.

Beyond the specific baseline energy quantities, higher rates, based on the marginal value of the energy, would be applied unless the industrial customer qualifies for an exemption to raise its baseline.

In essence, MH's new energy intensive rate proposal has three interrelated components:

1. new rate based on marginal value of foregone export revenue and marginal cost of generation;
2. a baseline, which would be set as an annual quantity based on a customer's prior maximum usage; and
3. exemptions, based on economic factors which would result in an increase in that customer's baseline if the exemption criteria was satisfied.

MH initially included the proposed rates and method of calculation of the baseline within its GRA; the exemption criteria was filed subsequently.

Underpinning MH's new energy intensive industry rate proposal was the principle that the revenue from such new rates would equal the foregone revenues of the same energy if it had been sold on the export market.

In short, MH sought to make the new energy intensive rate "revenue neutral" to the Utility.

16.3 MIPUG Motion

After MH's GRA filing, and also after the filing of the exemption criteria, the MIPUG advanced a motion to the Board seeking to sever the portion of the industrial rate that deals with new and expanded loads, from the GRA proceedings.

Following oral submissions on MIPUG's motion, the Board issued Order 8/08, which severed in part consideration of the new industrial rate from the GRA proceeding. At the GRA hearing, the Board and Interveners were provided the opportunity to cross-examine MH on the Utility's full proposal.

The Board, in Order 8/08, agreed that, at a minimum, consideration of the exemption criteria would occur at a special hearing. Interveners were also advised that if they so wished, they could bring new evidence forward at a separate hearing. To that end, the Board was advised, during the GRA hearing, that at least MIPUG intends to bring new evidence forward on this issue.

16.4 MH's Revised Position

While the Board and Interveners had the opportunity to explore the strengths and weaknesses of MH's proposed rates for new or expanding industrial load, so too was MH afforded the opportunity to continue to consider the issue.

During the proceedings, MH advised the Board and all parties that MH would not seek, through the GRA hearing, approval of the proposed energy intensive industry rates. Rather, MH indicated that it wanted an opportunity to review the information provided through the GRA process and have further discussions with its large industrial customers.

And, following further consideration and discussions, MH advised that it "…… may well refile or refine [its] proposal once the new hearing date is set and the process is established".

MH further advised that its request of the Board related to this issue, flowing from the GRA, would be for the Board to endorse in principle, the end date of December 31, 2007 for the setting of any baseline that may relate to a new rate for energy intensive industry. By the Board endorsing the date of December 31, 2007, as the end date for establishing a baseline, MH wants to put customers on notice for their planning purposes.

16.5 Service Extension Policy

In June 2005, MH suspended a long standing service extension policy which provided that MH would invest up to three times the anticipated annual revenues on facilities required to strengthen or extend the common grid to service customers (not including dedicated facilities). MH did not seek Board approval of this policy suspension.

MIPUG has suggested that the suspension may not be valid, or at the least, requires Board approval. Furthermore, MIPUG requested consideration should be given to refunding the costs incurred by customers due to the suspension.

16.6 Interveners' Positions

The Coalition

New and Expanded Load

The Coalition attributed the pressure on MH's load growth to load growth related to electricity intensive industry, and noted that load growth for electricity intensive industry for the next five years was projected to amount to 57% of the total load growth.

The Coalition stated that large energy intensive industry has been attracted to Manitoba on a scale large enough to threaten the Corporation's revenue position. Coalition noted that in the short-term this would impact by loads being diverted from the export market. In the long-term, for the Coalition the impact would not only be load diverted from the export market but also the implications of advancing costs in terms of new Generation and Transmission.

Energy Intensive Industry Rate

With respect to the energy intensive industry rate base line exemption criteria, the Coalition raised concerns with the MH's proposed dispute resolution process, which would come into effect in the event that there was a dispute with the establishment of the baseline or the granting an exemption between the Corporation and an industrial customer.

The Coalition held that if exemptions are to be granted they should be brought before the Board or be testable in some public forum. The Coalition opined that transparency is important because, to the extent exemptions are granted, there will be an impact on customer bills. The Coalition suggested MH address this issue when it refilled its proposal.

MIPUG

New and Expanded Load

MIPUG rejected MH's premise that new and expanded load from industry negatively affects all other customer classes, and held that such a premise would compromise in a material way fundamental ratemaking principles.

MIPUG stated that, should MH propose this ratemaking premise in future hearings, more detailed and comprehensive analysis is required. MIPUG contended that the Board will only be in a position to rule on such an important issue if it is presented with detailed analyses of both the expected short-term and long-term implications of the measure.

MIPUG contends that in the short-term, and due to export tie-line constraints, MH's ability to export additional power at times of high export prices is limited, and, as such, industrial load expansion would result in only minor impacts on MH's revenues over the short-term. Over the long-term, and in an era of expansion, MIPUG contends that the benefits arising from developing assets sooner should be included in the analysis, to allow the Board to properly assess the impacts that increased domestic loads have on long-term rate levels.

With respect to the Service Extension Policy, MIPUG opined the Utility neither had the authority nor should have suspended the policy without Board approval. Furthermore, for MIPUG, consideration should now be given to refunding costs that were disallowed by MH's unilateral suspension of the policy.

None of the other Interveners pursued this issue.

Energy Intensive Industry Rate

MIPUG accepted that MH had withdrawn its new industrial rate proposal and planned to refile an application, and that there is, therefore, no need for the Board to comment on this issue at this time. MIPUG stated that the Board should not set a date for the Corporation to return with its application, to allow MH to "take the time it needs" to properly support its proposal.

With respect to MH's proposed date of December 31, 2007 to establish a baseline for energy intensive industry rates, MIPUG's view was that the only benefit of establishing the baseline at that date would be to prevent "gaming" (i.e. new load being "rushed into service" ahead of a new rate and class being established). MIPUG's view was that the baseline should not be based on that date as other measures can be used to prevent "gaming", if and when a new rate and rate class was ultimately adopted.

MIPUG stated that the level of consultation with affected stakeholders should be commensurate with a rate proposal of this magnitude, and that the Corporation should take the time it requires to consult with the businesses and communities that may be affected by its proposal.

MKO

New and Expanded Load

MKO submitted that charging higher rates to new energy intensive general service customers would increase MH revenues and potentially provide for lower rates for all customers and greater "dividends" to the Manitoba government.

Energy Intensive Industry Rate

With respect to the energy intensive industry rate base line exemption criteria, MKO limited its comments to its view of the rate design principles that should be considered by MH in setting an energy intensive industry rate.

Firstly, MKO submitted that the proposed energy intensive industry rate violates several fundamental rate design criteria in that having such a rate would result in the charging of different rates to similar customers, and that the implementation of such a rate should only be done after the Manitoba government has set and communicated clear policy direction that such a rate is in the best interests of Manitoba.

Secondly, MKO advised of its concern that the proposed rate design will have a fixed implementation date that could “create a price cliff and intergenerational inequities”.

Thirdly, for MKO, the proposed energy intensive industry rate will differentiate customers based on “who” should receive net export benefits and “who” should not. MKO expressed a concern that MH would be “moving away” from the fundamental principle that all MH customers, including diesel community customers, should share the net export benefits, and that such a move may be a dangerous precedent and a decision to proceed with MH proposal should not be taken lightly.

Fourthly, MKO advised of a concern that the proposed rate will only apply to the large general service customer class. MKO submits that limiting the rate to one customer class violates standard rate design principles. MKO suggested that if limiting the sale of electricity to new energy intensive industry customers is a policy objective of the Manitoba government, then a more appropriate mechanism should be used instead of altering MH’s rates.

RCM/TREE

New and Expanded Load

RCM/TREE submitted that Energy Intensive Industry load growth will have a significant impact on MH's other customers, and that MH's load growth continues to exceed past projections with negative impacts on MH's finances, customers and the environment.

RCM/TREE further opined that MH may face energy shortages in 2009 to 2011, due to accelerated load growth.

Energy Intensive Industry Rate

RCM/TREE observed MH has acted on the energy-intensive industry issue by proposing a new rate for the general service large category. RCM/TREE also noted that the complexities of the proposed rate calculation are subject to consideration by the Board in a subsequent hearing.

Mr. Chernick suggested that MH's industrial rate proposal and exemption criteria were flawed, in that:

a) the baseline consumption level proposed was too high; and

b) the proposal allowed the baseline to increase to cover large amounts of increased load, with a total growth allowance of up to 39 GW.h (to qualifying companies).

Mr. Chernick noted that under MH's proposal if the industrial customer exceeded its baseline, the baseline in future years would be increased, so that marginal cost based rates would apply only in the first year of the load growth.

With respect to the proposed exemptions and/or discounts for economic development (payroll and taxes), Mr. Chernick suggested these would be the "wrong mechanism, implemented by the wrong entity", and would not be properly designed to meet the targeted objective, in that the discounts would destroy the conservation incentives of marginal-cost pricing and the computation of the cost of additional load would fail to count the environmental costs of reducing exports, and the lost benefits of the export revenues while new loads would be eligible for exemptions, regardless of the efficiency of the equipment and process installed.

Mr. Chernick stated that the baseline proposed to be established was too high and that the base usage for which a customer would be charged embedded rates should be less than a fixed historical base usage, such as the maximum annual usage in 2005-07 as proposed by MH. For Mr. Chernick, the base usage might better be set as 95% of the historical value in 2008, falling by 2% or so each year thereafter and with no future growth allowance.

Mr. Chernick stated the growth allowance eliminates any efficiency incentive provided by MH's proposal, and that "the only qualification for the growth allowance appears to be that the customer's load is less than 78 GW.h". Mr. Chernick opined that this proposed provision appears to eliminate any efficiency incentive for any customer adding less than 39 GW.h.

Mr. Chernick did not agree that incentives for economic development (exemption from the new rate due to economic development considerations) should be included in MH's rate structure. For him, the allocation of incentives should be the responsibility of an agency of the Manitoba government, not MH.

Mr. Chernick further suggested that if the Board were to want to use some of MH's revenues to support economic development; it should designate an amount to be collected and then direct that sum to be paid to the designated economic development agency, which should then decide which development projects are desirable and economically efficient.

Mr. Chernick suggested that revenues for economic development can be collected from the higher blocks of inclining-block rate structures, and that this proposal for the collection and disbursement of economic-development incentives would retain marginal-cost pricing for industrial rates, for both new and expanded loads, while not burdening MH with an economic-development role for which it has no special expertise or mandate.

RCM/TREE stated that each GSL customer should be charged the embedded energy rate for usage up to a baseline, and that marginal cost, including environmental costs, should be charged for consumption above that level. For Mr. Chernick, new general service large customers should be charged entirely at the marginal energy rate.

RCM/TREE proposes that the Board direct MH to participate in a collaborative effort with interested parties to determine if there are areas of agreement for the design of a new industrial rate proposal, and agreed with MH's proposal to fix December 31, 2007 as the end date for determining baseline levels.

16.7 Board Findings

Energy Intensive Industry Rate

The issue of the fairness of embedded cost rates being considerably lower than marginal costs or marginal values of energy, and the potential financial impact on the Utility, is not unique to Manitoba. The Board understands that other jurisdictions have, and continue, to face this issue.

And while the issue, in its basic form, exists for each new or expanded load by any customer, the financial implications of expanded load are magnified in the case of industrial customers.

While how best to address the issue in Manitoba remains an open question, one that will be pursued at a subsequent proceeding following MH's expected refiling of an application for a new industrial rate, it is an important issue that the Board is deeply interested in.

MH proposed a calculated rate for energy consumed above a baseline level, with that rate comprised of a marginal value of generated energy based on a "normalized" forecast of export values (i.e. 5.58¢ per kW.h), together with a marginal cost of transmission based on avoided costs (i.e. 0.816¢ per kW.h).

There was neither a marginal cost nor a marginal value for distribution included in MH's proposed new energy-intensive rate, this, because general service large customers have only nominal use of MH's distribution assets. The energy rate to recover the marginal cost, as proposed by MH, was also adjusted by the current demand charge of 0.740¢ per kW.h, providing for a proposed rate for new or expanded load for GSL > 100kV customers of 5.656¢ per kW.h (5.58 + 0.816 - 0.740 = 5.656).

While the Board appreciates that MH is not asking for approval of the energy-intensive rates at this time, the Board is concerned about the use of forecast export prices (as opposed to actual export prices) in the determination of marginal costs, and encourages MH to explore and advance other options for consideration at the separate hearing into this rate matter.

To explore other options and to avoid some of the concerns with the current calculation of an energy intensive rate, MH should consider:

- Baseline and growth allowance, and whether new industry coming to Manitoba [and existing industry] should get any growth allowance at heritage rates;

- Using data that is transparent and available to all customers and is not protected by a claim of confidentiality. The Board does not accept the bid for confidentiality when the information is publicly available from other industry or regulatory sources;
- Including time-of-use alternatives and variations to reflect the different values of energy at different times;
- Keeping the overall implications for revenue requirement neutral. The Board does not consider MH's proposal revenue-neutral as presented in MH's filed Proof of Revenue and IFF; and
- Perhaps including a marginal cost component or signal in rates for all classes, not just GSL. MH has identified that over the past ten years, more than 50% of the growth in Manitoba industrial loads is attributable to expansions in the electrochemical processing industry, an industry in which 70% of the costs can be incurred for electric energy used for processing purposes. The other major energy-intensive industry load (forecast by MH to significantly increase) is the pipeline compressor load.

A question to be considered is whether these specific industries should be targeted, or whether the concern is best addressed across the entire class, or perhaps all classes, served by MH.

Therefore, for the special hearing, MH will be expected to provide options, including its preferred option. The Board notes that MH may change its preferred option from what was presented at the GRA.

Export Contracts

MH should be required to reconcile its proposed treatments of energy-intensive industries with existing and proposed export contracts. Export sales do not create any direct or indirect Manitoba employment in the sense that domestic industry does.

It can be argued that MH should be pricing energy for domestic industry at average export price minus appropriate credits for direct and indirect job creation. While this might be difficult to administer, it would reward job creation and economic values input to Manitoba.

Further to the above, it would appear that the proposed energy-intensive rate may well discourage the further growth of existing industries. For example, if an industry added work shifts it would attract substantially-higher energy prices, in addition to shift premium payroll costs, even though this growth might well be employing off-peak energy (that being of low value as an export product).

TOU rates would significantly reduce the cost to industry for such expansion, and MH could benefit by gaining more value for its off-peak energy.

Time of Use (TOU) Rates

MH has suggested TOU rates will be considered after the new intensive-energy rate is implemented. This approach avoids addressing the issue of uneconomic exports and the considerable differences in domestic customer energy usage patterns. The Board, while recognizing that the implementation process for TOU may be protracted, believes that TOU should be built into the initial concept for the new rate.

In addressing confidentiality issues, MH has suggested that there is sufficient publicly-available information for the Board and Interveners to make informed judgements on the validity of MH’s marginal cost forecasts. This information (sources: SEP/NEB/etc.) should also allow MH to define time-of-use pricing on a conceptual basis for Board consideration in the new rate design.

MH has acknowledged that TOU billing could have favourable revenue results for the utility in most years. On the other hand, TOU rates should provide an opportunity to industry to optimize its energy usage and thus benefit from TOU rates.

Marginal Cost Values for Export

MH's case for increased rates to energy-intensive industry assumes that all energy used by industrial growth could alternatively be sold as peak market exports. Contract prices (generally below peak market values) apply during low flow years; only part of the exports achieve better than contract prices in average flow years, and surplus energy prices tend to fall below contract prices in high flow years. In light of the transmission tie-line constraints, the Board questions MH assumptions on the relative value of export sales and domestic load growth during the off-peak period.

Accordingly, the Board directs MH to provide an in-depth analysis of the value of peak versus off-peak energy sales into the MISO market.

MH also employs an element of avoided costs in determining the marginal cost of energy to be employed for intensive-energy usage rates. This would be appropriate if MH was actually contemplating deferral of new generation or transmission on the basis of reduced domestic load growth. In reality, MH is advancing new generation and transmission to meet new export contract sales now under negotiation.

he Board directs MH to report on the specific deferral values that could be achieved by constraining industrial load growth.

Consumption Baseline

In defining the new intensive-energy rate and by its application, MH focussed on industrial customers using more than 39 GW.h of energy per year. However, the proposed rate schedule provided marginal cost second block rates for all GSL customers.

In the Board's view, MH should have provided the impact analysis for all GSL customers, in order to justify the proposed 39 GW.h floor for new rate exemption. Accordingly, the Board directs MH to provide an analysis for all GSL customers, to justify the 39 GW.h floor for new rate exemption, and to report on the potential extension of the rate and or lowering of the threshold.

Fairness Principles

There was at least a sense of a degree of consensus from all parties that selling energy domestically at prices well below the average export market value is an issue that must be addressed. Beyond that, the Interveners were quite divided on what is a fair price level and who should pay the higher price if there is to be one.

Currently under the COSS, all domestic customer classes are allocated about 3.0 to 3.5¢/kW.h in costs for generation and transmission. Some customers pay more and others pay less than their allocated costs. No class pays the average export market value. The issue is further distorted because different classes are allocated varying amounts (zero and upward) for local distribution services. The Board will be looking to reconcile the current rate proposal with cost causation principles.

Service Extension Policy

It would appear that the policy (pre-2005) was intended to support industrial expansion in areas of the Province that did not have access to 30 kV or greater power. The scale of the investments incurred and revenues gained under this policy were not identified at this hearing. MH did not carry out a detailed feasibility test prior to suspending the policy; for the longer term, and in light of the proposed new energy-intensive rate, that policy may be reconsidered by MH.

The Board considers that the service extension policy logically falls under the Terms and Conditions that are generally believed to be integral with rate setting. Without reaching a conclusion on legal jurisdiction at this time, the Board will direct MH to file an economic feasibility test report with the Board on September 30, 2008, on the historical application of the service extension policy. In that report, MH is to define the underlying rationale for the existing policy, as it existed and explain why that rationale apparently no longer exists, together with an accounting of instances since the policy was suspended where customers paid more to have a service connection than other previous customers.

17.0 Presenters' Positions

17.1 Mr. Ciekiewicz

Mr. Ciekiewicz's view is that the March 31, 2007 interim rate increase was not justified because it was prompted by the occurrence of only a short period of low water levels in 2005/06, rather than the "long established method" of using longer periods of time to set rates.

Mr. Ciekiewicz also indicated that MH's proposed residential rate increase, and the approach the Corporation used to develop its inverted rate structure proposal penalizes home owners who are dependent on electrical heating, and/or have converted to electrical heating. He was concerned that all-electric rate-payers will face an increase greater than the rate of inflation. He argues that those who do not have the option of other fuel sources for heating should get a rebate, rather than an increased rate. As well, he predicted that inverted rates will result in heating choices by rate-payers that are not friendly to the environment.

Mr. Ciekiewicz was also concerned that it is the nature and length of the firm export contracts that constitutes the main risk affecting the financial well-being of MH, and that in years of drought the costs associated with fulfilling firm export commitments could wipe out the retained earnings.

He opined that the Board has jurisdiction over MH's export contracts, by way of section 47 of *The Public Utilities Board Act*. He recommended that the firm export contracts negotiated by MH include clauses that the contracts can be cancelled in the event of drought conditions, or that certain incentives on export prices be included in the contracts as a concession to the export customers for this cancellation clause.

Mr. Ciekiewicz also challenged the meaning of firm contracts as interpreted by MH, he based his challenge on a definition from the North American Electric

Reliability Corporation that implies that the obligation to provide power ceases when the "system reliability is threatened, or during emergency conditions".

Mr. Ciekiewicz also questioned MH assertions that the incremental costs of new office building over the efficiency savings will be cost neutral, and never affect rates. He did not accept that the $278 million price tag for the new head office will not adversely affect retained earnings, and by extension, rates.

Mr. Ciekiewicz was unclear as to whether NCN will be liable for one-third of any losses that may materialize if a future drought prevents MH from meeting its export sale commitments, and sought to have the issue clarified.

Mr. Ciekiewicz made reference to what he termed contradictory responses from MH on some Information Requests with respect to the Brandon Coal Fired Thermal Generating Station Unit 5. One apparent contradiction cited appears that MH has stated that the closure of the Unit 5 would result in firm energy deficits in 2013 to 2025 and would reduce the surplus available for export, while MH stated elsewhere in its responses to interrogatories that the thermal plants were not constructed to support export sales. Another contradiction in MH responses noted by Mr. Ciekiewicz was that MH stated in one Information Request that Unit 5 produces an average $20 million to $30 million in net income per year, while the Corporation's response to another Information Request stated that MH does not calculate the annual revenues or net income for the unit.

17.2 Mr. Forrest

Mr. Robert Forrest provided an electronic submission; he indicated opposition to MH's proposed rate increase.

Mr. Forrest stated that rates were already too high and that the current increase was not justified because MH had reported in the news a large surplus and that an increase had already been granted.

17.3 Mr. Rader

A written presentation in the form of a letter from Mr. Robert Rader, Managing Director, Koch Fertilizer Canada, Ltd., to Mr. Bob Brennan, President and Chief Executive Officer, Manitoba Hydro and to Public Utilities Board, dated February 11, 2008 was read into the record of the proceeding.

Mr. Rader made reference to the document entitled General Service Large – New or Expansion Rate Baseline Energy Consumption Level and Exemption Application Discussion Paper. He did not agree with the proposed annual growth allowance of GW.h, and recommended the growth allowance be a percentage of the base versus a fixed number.

Mr. Rader also recommended that expenditures made to reduce energy consumption should be credited at 100% rather than the 50% contemplated in the document.

Mr. Rader also stated that while his company may expand its production volume without increasing its payroll, it would still be providing secondary benefits to truck and rail companies, and that such economic benefits should be taken into account in considering exemptions from any new industrial rate.

17.4 Mr. Svidal

Mr. Kaare Svidal is the manager of the Energy Management Group of Enbridge Pipelines, and he stated that MH had made presentations across the province on the proposed new industrial rate, and that in these presentations MH had indicated that pipeline companies provide very little economic benefit to the province. He disagreed with MH on that issue, and argued that Enbridge has provided considerable value to Manitoba in the last 58 years.

He stated that Enbridge pays annual salaries of $5 million to Manitobans, and $7 million of annual property taxes in the province. He also noted that Enbridge benefits industry in Manitoba in that it delivers all the refined products to Manitoba in a reliable and economical way.

He also noted that the growing Manitoba oil producing industry, which generated $400 million in capital expenditures in 2006, relies on Enbridge to deliver their product to US markets.

He pointed out that Enbridge is a long-term financially stable A-rated base load customer of MH whose continued presence in Manitoba is required to justify the MH infrastructure in place today. He reminded the Board that his firm had switched from diesel to electrical pumping stations in 1965 at the request of the government of Manitoba, and that Enbridge was a long-term and committed customer of MH.

17.5 Mr. Turner

Mr. Bill Turner is plant manager of Canexus Chemicals at Brandon and the Chairman of MIPUG. He indicated that low-cost electricity is necessary for industry to remain competitive in Manitoba because it offsets existing geographic, climatic and other disadvantages of locating in this province, disadvantages that also include higher taxes and a growing foreign exchange problem.

Mr. Turner stated that MIPUG members pay rates that are 8% greater than the cost to MH of providing the firms the electricity they consume; MIPUG member firms were reported to consume 5,000 GW.h. annually at a cost in excess of $150 million.

Mr. Turner further advised that MIPUG members employ 4,500 Manitobans, and that the association's membership have capital assets employed in Manitoba greater than $2 billion. Mr. Turner also stated that 90% of MIPUG members' sales were exports.

Mr. Turner indicated that the new industrial rate is a new policy direction from MH with major implications for the use of energy and the development of industry within the province. He expressed frustration that the discussion meetings between MIPUG and MH on this issue were ineffectual, and that the discussions were not open and transparent. He expressed concern that the Province of Manitoba has not participating directly in the new industrial rate discussions, and stated his view that the Province may be poorly informed on the issue.

He suggested there will be far reaching impacts if the new industrial rate is adopted, in particular to the employees of affected companies and their families, and to rural and northern communities in which the firms are located.

Mr. Turner explained that with respect to his company, Canexus, 60% of the firm's manufacturing costs are for electricity ($48 million annually). He stated that 100% of his firm's product is exported, with 95% going to the US. Mr. Turner noted that the recent strengthening of the Canadian dollar had resulted in major income losses for Canexus.

He stated that his company has 6 plants in other provinces and one in Brazil, and that when the firm is not required to operate at full capacity, the firm will operate the factories with the lowest electricity cost. He also pointed out that his company is one of MH's largest DSM participants.

Mr. Turner stressed that companies such as Canexus require stability and certainty in electrical rates in order to make sound business decisions as to where they locate. He indicated that his company relocated a plant from Louisiana to Manitoba in 2004, at a cost of $55 million, because of electrical rates. He stated that further expansion plans are now being reconsidered due to the uncertainty of rates in Manitoba over the last 3 years.

He further stated that through his association with various industry groups, that business in general is concerned with the new industrial rate issue. He declared his disappointment that MH has stated that sodium chlorate companies and pipelines provide very few economic benefits in this province, and he advised of benefits being provided to the people of Brandon and the related construction trades.

18.0 IT IS THEREFORE RECOMMENDED THAT

1. MH seek independent advice as well as advice from government and its credit rating agencies as to the merits of a possible elimination of the sinking fund requirements;

2. The Board remains concerned with the Corporation's ongoing aggressive deferral and capitalization accounting practices, and recommends that MH consider an early adoption of IFRS standards. The Board further recommends that both the Board's prior concerns and current views, as expressed in this Order, be brought to the attention of both MH's external auditors and its independent consultant assisting the Corporation with its IFRS transition strategy;

3. Because of the current and future impact on rates of the unprecedented capital program and related tentative export sales contracts, the Board repeats its recommendation to government that *The Public Utilities Board Act* be amended to make the Board's regulation of MH equivalent to the Board's regulation of Centra Gas, by removing the exemption now provided under Section 2(5) of the Act;

   Or alternatively, the Board recommends that government renews the mandate provided to the Board in 1990 (via OIC 1990-177), a mandate that provided for a detailed and comprehensive integrated review of MH's Major Capital Projects in light of pending export commitments (then-covering the period 1990 to 2009). Such an updated mandate would allow for a similar review covering the period 2009 to 2028;

4. Because of the impact (and potential impact) on consumer rates, the Board recommends MH seek the Board's prior review and approval of

future agreements involving the joint ownership of Generation and Transmission assets;

5. With respect to DSM and Low-Income Energy Efficiency Programs:

a) MH accelerate its DSM plans to achieve targets earlier than presently scheduled, and at the same time, consider changing its accounting approach to one that provides for the amortization of DSM costs over a period no longer than five years;

b) MH to continue to pursue environmental objectives on an integrated natural gas electricity basis, and in particular, to consider the position of low-income customers increasingly faced with higher energy costs and too often lacking the funds and know-how to achieve needed upgrades that would reduce their energy bills and GHG emissions;

c) MH undertake changes to its furnace replacement program so as to increase low-income household participation in the early replacement of inefficient natural gas furnaces. Changes to the program, as recommended by the Board by way of Order 99/07, would better provide this opportunity and should provide energy savings for low-income customers and significant non-energy benefits to society (reduced GHG emissions), the Utility (in the form of less risk of the conversion of natural gas space heating to space heating by electricity), as well as to all participants in the program;

d) MH incent landlords to participate in the low-income DSM program, to improve the energy efficiency of their properties for the benefit of their tenants and the environment;

e) MH expand finance options for low-income customers, including subsidized Power Smart loans for the furnace replacement program, with an option either requiring repayment on the sale of the residence or, alternatively, a 10-year lease financing program as suggested by Mr. Dunsky;

6. The Board recommends government consider:

a) Seeking from the Federal government an exemption from GST for residential customers for space heating, as heat in Manitoba in winter is a necessity like food; and

b) Funding low-income and DSM programs, by setting aside all or a portion of provincially and or municipally-sanctioned sales taxes charged to residential customers on energy used for heating purposes.

7. The Board recommends government consider establishing a separate entity to manage the Corporation's DSM and low-income initiatives. The Board concludes that MH's full energies and focus should be placed on the effective implementation of its long-term expansion plans toward meeting the demand for electricity and natural gas to develop over the next few decades. The Board can envision MH establishing aggressive goals for the reduction of domestic energy consumption for such a new entity to meet or exceed, together with providing adequate funding to meet those goals (energy conserved is energy available for export).

19.0 IT IS THEREFORE ORDERED THAT:

1. MH file with the Board, MH's 2007/08 Annual Report, with audited financial statements, immediately after the Corporation meets its statutory filing requirement with respect to the Legislature;

2. With respect to MH's export program, MH to file a report with the Board by January 15, 2009 on the following:

   a) Overview of strategy, options, historical costs and revenues;

   b) Monthly historical export prices for the last five years, disaggregated for both peak and off-peak periods;

   c) Existing and pending export contract commitments, with annual forecast revenues both aggregated and also disaggregated (in confidence if necessary);

   d) Forecast export revenues until 2028, identifying opportunity sales distinct from firm contract sales and broken down by peak/off-peak;

   e) Detailed assumptions used in export market price forecasts (filed in confidence if necessary). MH to resubmit its export pricing forecasts to reflect recent realities of market prices and exchange rates;

   f) A testing of MH's assumptions through detailed sensitivity analyses for upper/lower quartile water flows, foreign exchange, domestic load growth and natural gas prices; and

   g) Given the crucial nature of the Corporation's export contracts and assumptions, with potential impacts on domestic rates, MH file for Board review all proposed export contracts;

3. MH to provide the Board with:

   a) Specific quarterly reports on energy supplies (including imports), domestic demand, and export sales (e.g., similar to NEB volume and price data); and

   b) Annual reports on the LUBD Program performance;

4. MH to provide the Board an independent assessment of the Corporation's relative weighting of fixed vs. floating debt, and file a report with the Board on or before June 30, 2009 ;
5. With respect to IFRS, the Board requires MH to file on or by January 15, 2009 :

   a) A report explaining and quantifying the proposed transition to IFRS;

   b) A copy of MH's consultant's report indicating the projected impact of the adoption of IFRS on the Utility, specifically with respect to MH's current deferral and capitalization approaches, and as to the likely status of goodwill now recorded in its accounts;

   c) An articulation of the new proposed MH accounting policies detailing how they comply with IFRS;

   d) An explanation of any changes to the internal operations of MH which may be planned or contemplated to offset any increased annual expenses expected as a result of the adoption of IFRS, together with MH's and its consultant's views of the Board's regulatory options, including a review of the pros and cons of special purpose financial reporting for utilities for rate setting purposes; and

e) An updated IFF and CEF (covering the years 2008 to 2028) reflecting the expected impact of the new standards and assumptions of related operational changes as may be planned or contemplated by MH;

6. MH to undertake and file with the Board, by June 30, 2009, an independent benchmarking study of key performance metrics, using the most currently-available data and including:
   a) Primary key drivers of OM&A in each operational division [Board preference is for a divisional break-down to allow for a comparison with other utilities, even if the comparison needs to be limited to specific divisions/activities],
   b) Comparable other Canadian Utility data for each of the drivers;
   c) Key comparison indicators, including staffing levels;
   d) A comparison with and discussion of industry best practices; and
   e) Potential improvement areas.

   The Board expects to be apprised of the scope of the benchmarking study in advance of it being undertaken, and will anticipate being provided a study outline on or before January 15, 2009, to allow the Board the opportunity to provide direction and/or comment.

7. MH to undertake and file with the Board an Asset Condition Assessment Report by June 30, 2009, that defines:
   a) major assets and categories of assets;
   b) the estimated remaining economic life of each major asset and category of asset;
   c) an indication of the implications for OM&A costs related to required and scheduled maintenance;

d) a listing of scheduled, planned or anticipated major upgrading/decommissioning of major assets and/or categories of assets;

e) forecast expenditures for planned renovations and/or replacements with respect to now available energy supply and transmission; and

f) Dam Safety Condition Assessment and Maintenance requirements.

In advance of the commencement of the Asset Condition Assessment Study, MH to file with the Board detailed Terms of Reference containing the scope for undertaking such a study and a definition of the resources to be employed, on or before January 15, 2009.

8. MH to file a report with the Board by June 30, 2009 detailing the final all-inclusive capital cost of the corporate head office project (including such things as construction cost, furniture and equipment, telecommunications, equipment leases, etc.), and the contemplated or planned operating actions to recover incremental costs related to the new head office. (The Board reaffirms that no additional incremental costs are to accrue or be allocated to Centra as a result of the new MH head office.)

9. MH to file a report with the Board by January 15, 2009 indicating:

a) whether the current depreciation rates for the Generation, Transmission, Distribution and other assets purchased from Winnipeg Hydro [including Slave Falls] and the Brandon Coal Plant remain appropriate; and

b) the related proposed capital replacement, expansion and decommissioning costs;

10. To gain a further understanding of the implications of the capital expenditures now contemplated, MH is to file with the Board by January 15, 2009 :

    a) An updated Capital Expenditure Forecast, and Integrated Financial Forecast covering the fiscal years 2007/08 to 2027/28;

    b) An updated Power Resource Plan covering the years 2008 to 2028. The updated Power Resource Plan should provide alternative scenarios with/without implementation of the pending new export contracts and related capital spending. The report should also indicate the remaining feasible hydro generation opportunities, following Wuskwatim, Keeyask and Conawapa, where and what possible quantity of energy would be expected, and the assumed development timeline; and

    c) An updated Load Forecast covering the fiscal years 2007/08 to 2027/28; the Load Forecast should reconcile projected and actual DSM savings;

11. The Board will direct MH to propose to the Board on or before January 15, 2009 the terms of reference for a regulatory review of MH's planned Capital Program and its impact on consumer rates;

12. MH to prepare a study, and file it with the Board by January 15, 2009, a thorough and quantified Risk Analysis, including probabilities of all identified operational and business risks. This report should consider the implications of planned capital spending and take into account revenue growth, variable interest rates, drought, inflation experience and risk, and potential currency fluctuation;

19.0 Board Directives

13. MH to file by September 30, 2008, for Board approval, a conceptual outline for an in-depth and independent study of all the operational and business risks facing the corporation set out in the previous directive (12);

14. MH to provide the Board, by June 30, 2009, recommended risk mitigation measures and a review of possible suitable capital structures, given the capital expansion now planned or contemplated, with risks quantified;

15. MH to provide the Board by June 30, 2009, a summary of existing programs and potential future programs defining the arrangements for increased or modified (augmented) water flows within and external to Manitoba. The summary should include the specifics of each program and mitigation and compensation related thereto;

16. MH to submit a report to the Board on January 15, 2009 on the 300 MW of additional wind energy project(s), with a discussion of the business case, general wind strategy, prospects and timelines for the project, as well as with respect to the prospect for a further 600 MW consistent with the government's identified longer-term target of 1,000 MW of wind energy. The Board will also require access to the agreements for the existing 100 MW St. Leon wind project, and an opportunity to review the pending agreements for the 300 MW project(s);

17. MH report to the Board before June 30, 2009, as to whether there are greater global environmental (GHG) and economic benefits to be achieved by exporting hydraulically-generated electricity than would be achieved by fuel switching (from natural gas to electricity) and/or

geothermal within Manitoba. The report should address and clearly define the relative environmental and economic benefits of these exports. The overall assumptions and impacts on the Load Forecast should also be included in the report;

18. With respect to low-income programs, MH to prepare and report on the following:

a) MH to consult with stakeholders on its enhancements to its low-income programs to ensure it adequately addresses low-income needs, and to report to the Board by September 30, 2008 on the results of the consultation and subsequent development of and implementation of this program;

b) MH to provide an update on the status of the current natural gas furnace replacement program (including actual and forecast take-up rates), as well as reports of possible changes to the program relative to the suggestions put forward by Mr. Dunsky, on or before September 30, 2008;

c) MH to meet with MKO and representatives from the diesel communities to discuss the issue of the access of those communities to MH's low-income programs, and to report to the Board on the outcome of these discussions on or before September 30, 2008;

d) MH to propose for Board approval (as soon as possible but no later than September 30, 2008) a low-income bill assistance program, where such a program would occur in conjunction with and complimentary to an expanded low-income DSM program;

e) MH to file with the Board on or before June 30, 2009 a draft plan, with projected implications, to increase the Corporation's integrated (natural gas and electricity) energy-efficiency initiatives with respect to low-income households, so as to allow for reduced energy consumption for all such households within a decade;

f) MH to report back to the Board on the potential for a low-income and a general refrigerator replacement program, and provide the merits of such programs, on or before June 30, 2009; and

g) MH to accrue interest on the AEF balance, to ensure additional funds are available to fund expanded low-income energy efficiency programs and to avoid the loss of "purchasing power" of the AEF due to continuing inflation;

19. MH to refile the COSS by January 15, 2009 on the following basis:

a) As defined by Order 117/06;

b) Incorporating diesel and exports in the same fashion as other domestic customer classes;

c) The assigning of 50% fixed and 100% variable thermal plant costs to the Export class;

d) Assign DSM cost directly to export class and add DSM energy savings to domestic load for Generation cost-sharing purposes;

e) Use the most recent actual [not forecast] export prices to establish export revenue in the COSS; and

f) Use actual [eight year] energy [SEP] prices and energy use profiles in Generation energy weighting process;

20. MH to provide and file with the Board by January 15, 2009 a revamped Marginal Cost (MC)-COSS analysis, one reflecting needed refinements to generation, transmission and distribution marginal costs. This should include specific demonstrations of how alternative MC adjustments could be applied to an embedded COSS. Among the scenarios to be explored, MH should consider the addition or blending of marginal costs to embedded costs prior to comparison to class revenues;

21. MH to file all appropriate data [e.g. SEP/ NEB/ MISO clearinghouse information and avoided cost information etc.] required for input to the marginal cost determinations for generation, transmission and distribution and to further define the key assumptions employed by MH in support of this process, with the Board [on a confidential basis if necessary] on or before September 30, 2008;

22. MH to provide a planned implementation strategy outline by September 30, 2008 for TOU Rates as appropriate to the classes with required metering technology already in place. Alternative rate strategies should be included for consideration at the upcoming Energy Intensive Industry rate hearing;

23. MH file a plan by January 15, 2009 outlining the pros and cons of the various potential inverted rate strategies under consideration, and the MH-proposed course of action to address this issue over the next five years;

24. MH to plan to re-balance demand and energy charges on a revenue-neutral basis, and submit a 5-year transition plan for the Board's approval at the earliest of June 30, 2009, or the next GRA;

25. MH to continue with the consolidation of process of the GSS and GSM customer class consolidation, and provide the Board with a proposal by June 30, 2009 for a stepped-up program and a timeframe for completion;

26. MH to include in its future application to finalize the four interim Orders related to Diesel Rates, reports on:

    a) the fairness of the rate approach with respect to non-senior government accounts (the Board is concerned that the rates restrict the economic development prospects for the communities and drive up service and commodity costs);

    b) the efficacy of the current rate schedule for non-government accounts (data on aged accounts receivable, delinquency and bad debts together with the collection policies in place for the four communities will be required); and

    c) the effects of the current approach to rates and consumption restrictions on the four communities, a detailed review of consumption levels and collection practice from the former Diesel communities that have been connected to the grid which will serve as a comparison; and

    d) MH to report to the Board by September 1, 2008, as to the balances and status of the diesel zone accounts; to ascertain whether existing interim rates are fully recovering operational costs;

27. MH to provide a report to the Board by January 15, 2009 evaluating the Surplus Energy Program. The report should employ monthly historical data from 2000 to 2008 to analyze and compare the benefit and costs of the actual operation of the hydraulic generating system

pursuant to various less aggressive sales strategies. This report should address the relative merits of withholding surplus energy from sales at off-peak periods;

28. MH to file an economic feasibility test report with the Board by September 30, 2008, on the historical application of the service extension policy. In that report, MH is to define the underlying rationale for the existing policy, as it existed, and explain why that rationale apparently no longer exists, together with an accounting of instances (since the policy was suspended) where customers paid more to have a service connection than other previous customers;

29. With respect to an Energy Intensive Industry rate for new and expanded load, MH is to file an updated application with the Board on or before September 30, 2008. Such an application should include:

    a) An in-depth analysis of value of on-peak versus off-peak energy sales into the MISO market;

    b) A report on the specific deferral values that could be achieved by constraining industrial load growth; and

    c) An analysis for all GSL customers, to justify the proposed 39 GW.h floor for new rate exemption, and report on the potential extension of the rate and/or lowering of the threshold;

30. MH to file before January 15, 2009, supporting information for Board review of the 4% April 1, 2009 conditional increase. In addition to the information identified above to be filed by January 15, 2009, MH is to include:

    a) first ,second and third quarter 2008/09 unaudited financial results and statements; and

b) an updated forecast of net income for 2008/09, reflecting existing water energy in storage conditions.

THE PUBLIC UTILITIES BOARD

"GRAHAM LANE, CA"

Chairman

"H. M. SINGH"

Acting Secretary

Certified a true copy of
Board Order 116/08 issued by
The Public Utilities Board

Acting Secretary

Appendix A

Appearances

R. Peters	Counsel for The Manitoba Public Utilities Board (Board)
O. Fernandes P. Ramage	Counsel for the Manitoba Hydro Electric Board (Hydro)
B. Williams	Counsel for Consumers' Association of Canada (Manitoba) Inc./Manitoba Society of Seniors Inc./ Winnipeg Harvest (COALITION)
T. McCaffrey J. Landry	Counsel for Manitoba Industrial Power Users Group (MIPUG)
M. Anderson	Representing Manitoba Keewatinook Ininew Okimowin. (MKO)
W. Gange D. Rempel P. Miller	Counsel for Resource Conservation Manitoba/Time to Respect Earth's Ecosystems (RCM/TREE)
D. Buhr	Counsel for the City of Winnipeg (CITY)
J. Scott (np) T. Trull (np)	TransCanada Keystone Pipeline GP Ltd.

(np)- not present at the hearing

Appendix B

Witnesses for Hydro

V. A. Warden	Vice-President, Finance & Administration and Chief Financial Officer
H. M. Surminski	Section Head, Generation System Studies, Resource Planning and Market Analysis,
K. R. Wiens	Division Manager, Rates & Regulatory Affairs
W. J. Derksen	Manager, Corporate Accounting
C. S. Thomas	Manager, Electric Rates & Regulatory Department
L. J. Kuczek	Division Manager, Consumer Marketing and Sales
I. S. Page	Manager, Financial Planning Department
W. Hamlin	Senior Energy Policy Officer, Energy Policy & Emissions Trading, Power Supply

Appendix C

Interveners of Record

1. Consumers' Association of Canada (Manitoba) Inc./Manitoba Society of Seniors/Winnipeg Harvest (Coalition)

2. Manitoba Industrial Power Users Group (MIPUG)

3. Manitoba Keewatinook Ininew Okimowin (MKO)

4. Resource Conservation Manitoba/Time to Respect Earth's Ecosystems (RCM/TREE)

5. City of Winnipeg (CITY)

6. TransCanada Keystone Pipeline GP Ltd. (KEYSTONE)

Appendix D

Intervener Witnesses

Coalition

W. Harper	Manager, Econalysis Consulting Services, Inc.
P. Dunsky	President, Dunsky Energy Consulting

MIPUG

A. McLaren	Consultants, InterGroup Consultants Ltd.
P. Bowman	

RCM/TREE

P. Chernick	President, Resource Insight Inc
S. Weiss (np)	Sr. Policy Analyst, NW Energy Coalition

Appendix E

Presenters

Mr. A. Ciekiewicz	Citizen
Mr. B. Turner	Chair, Manitoba Industrial Power Users Group
Mr. K. Svidal	Manager, Energy Management Group, Enbridge Pipelines
Mr. R. Rader (written only)	Managing Director, Koch Fertilizer Canada, Ltd.