## SUBJECT: Capital Costs

## REFERENCE: CAC/MH I-002a

## QUESTION:

If the P50 estimate is considered the "most likely Base Estimate amount", what does the Point Estimate represent?

## RESPONSE:

The Point Estimate is the risk-free, escalation-free (or bare) costs based on an initial set of assumptions and current market conditions (i.e. overnight costs) (refer to Appendix 2.4 page 1 of 27). The Point Estimate is comprised of both the direct and indirect cost estimate, developed on first principles, manufacturer quotes, general industry costs and historical costs. It does not include contingency or labour management reserve.

The base estimate includes the point estimate plus contingency. A P50 base estimate would include the point estimate plus P50 contingency which has an equal likelihood of cost overrun or underrun.

## REFERENCE: Question CAC/MH I-001

## QUESTION:

Please provide a copy of the actual corporate policy/standard as originally requested.

## RESPONSE:

This approach was adopted following an Executive Committee Recommendation which is not a published document, but reflects the corporate direction regarding capital cost estimates for new major generation and transmission where the estimated capital cost is great than $250 million.

**SUBJECT: Keeyask**

**REFERENCE:** CAC/MH I-003a

**QUESTION:**

With the inclusion of the Management Reserves for Labour and Escalation, what P value is the Keeyask Base Dollar cost of $4.1 B equivalent to?

**RESPONSE:**

Please see Manitoba Hydro's response to PUB/MH II – 447.

## SUBJECT: Keeyask

## REFERENCE: CAC/MH I-003b

## QUESTION:

The response states that the $3.3 B value used in Appendix 9.3 excludes the cost of the KIP. However, if one sums the values included in the third column of the Table provided (excluding the KIP) one gets $2.93 B (2.86+0.55+0.11-0.59), not $3.3 B. Please reconcile.

## RESPONSE:

To clarify, The capital cost estimate of $3.3 B (2014 constant dollars) provided in Table 001 of Appendix 9.3 is a base dollar cost estimate for the Keeyask Generating Station only. The Reference NFAT economic analysis does not include labour reserve, and capital costs incurred or estimated to June 2014 (including KIP costs) as they are considered sunk costs and common to all development plans.

In Manitoba Hydro's response to CAC/MH I-3 (b), to illustrate that the Keeyask capital cost estimate used in the NFAT economic analysis was consistent with that used in IFF12, Manitoba Hydro identified the amount of KIP costs and removed all Sunk Costs (which included KIP) and de-escalated to 2012$.

| | **Table 3, Appendix 2.4**<br><br>(2012 dollars) | **Table 001, Appendix 9.3**<br>Economic Summary Table<br>(Ref-Ref-Ref)<br>(2014 dollars) | **Table 001, Appendix 9.3**<br><br>(2012 dollars) |
|---|---|---|---|
| Purpose of Estimate | Capital cost estimate used in the Integrated Financial Forecast IFF12 | Reference capital cost estimate used in the NFAT economic analysis | De-escalated to 2012 dollars to be able to compare to Table 3 estimates |
| Point Estimate Keeyask Infrastructure Project (KIP) | $0.29 B | $0.30 B | $0.29 B |
| Point Estimate for Keeyask Generating Station | $2.76 B | $2.86 B | $2.76 B |
| Contingency* | $0.53 B | $0.55 B | $0.53 B |
| Management Reserve<br>• Labour Reserve<br>• Escalation Reserve** | <br>$0.38 B<br>$0.12 B | <br>-<br>$0.11 B | <br>-<br>$0.10 B |
| Sunk Costs from March 31, 2012 to June 30, 2014 | | -$0.59 B | -$0.57 B |
| **TOTAL BASE DOLLAR COST** | **$4.1 B** | **$3.3 B** | **$3.1 B** |
| Reconcile Labour Reserve | -$0.38 B | | $0.38 B |
| Reconcile Escalation Reserve portion allocated to Labour Reserve | -$0.02 B | | $0.02 B |
| Reconcile sunk costs | -$0.57 B | | $0.57 B |
| **Comparative Totals** | **$3.1 B** | | **$4.1 B** |

* Reference capital cost estimate for Keeyask is based on a P50 Contingency
** Reference capital cost estimate for Keeyask is based on 0.6%/yr real escalation

## SUBJECT: Keeyask

## REFERENCE: CAC/MH 1-003b

## QUESTION:

Please explain why, for purposes of the economic analysis, the Labour Reserve was excluded from the costs for Keeyask.

## RESPONSE:

Please refer to Manitoba Hydro's response to PUB/MH II-447.

## REFERENCE: Question CAC/MH I-004

## QUESTION:

Please provide an actual copy of Corporate policy G911 as originally requested.

## RESPONSE:

A copy of the Corporate Policy G911 is attached.

Subject: Projected Escalation, Interest, Exchange and Hurdle Rates
Number: G911
Revised: 2011 08 05

Contact: For interpretation or further information on this policy, contact:
Economic Forecasting Consultant

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**Projected Escalation, Interest and Exchange Rates**

Projected escalation, interest and exchange rates will be used for:

- project evaluations
- estimates in planning studies
- all input to the Capital Expenditure Forecast (COPP 98.13)

**Process of Development for Escalation, Interest, Exchange and Hurdle Rates**

- Economic Analysis recommends the projected escalation, interest, market exchange and hurdle rates.
- Executive Committee authorizes the recommended escalation, interest, market exchange and hurdle rates.
- Financial Planning enters applicable projected rates into the SAP system for corporate use.

See the following for further detail:

Projected Escalation Rates—Estimates of escalation will be applied at applicable rates as outlined in the Projected Escalation, Interest and Exchange Rates (G911-1)

Projected Interest Rates (G911-2)
Projected Exchange Rates (G911-3)
Hurdle Rates (G911-4)
Composite Index Matrix for Escalating Historical Cost Estimates (G911-5)

For more information on this policy, contact:
Economic Forecasting Consultant

# PROJECTED ESCALATION, INTEREST, & EXCHANGE RATES - G911-1

| | Historical | | | | | Projected** | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ITEM (Fiscal Year) | 2007/08 | 2008/09 | 2009/10 | 2010/11 | 2011/12 | 2012/13 | 2013/14 | 2014/15 | 2015/16 | 2016/17 | 2017/18 | 2018/19 & on |
| *1. Hydro-Electric Generation Plant | | | | | | | | | | | | |
| Weight | | | | | | | | | | | | |
| Earthworks 0.16 | 5.1 | 7.2 | -4.2 | 5.1 | 6.3 | | | | | | | |
| Concrete 0.15 | 6.1 | 7.8 | -5.2 | 7.0 | 5.3 | | | | | | | |
| Equipment 0.25 | 7.3 | 6.8 | -8.3 | 6.8 | 4.9 | | | | | | | |
| Infrastructure Construction/Operation 0.21 | 4.9 | 6.7 | -2.1 | 4.0 | 4.8 | | | | | | | |
| Permitting, Engineering & Administration 0.23 | 2.7 | 3.0 | 0.1 | 6.0 | 4.7 | | | | | | | |
| 1.00 | | | | | | | | | | | | |
| Hydro Projects: Composite Escalation Rate | 5.2 | 6.1 | -4.0 | 5.8 | 5.1 | 1.8 | 2.1 | 2.1 | 1.9 | 1.9 | 1.9 | 1.9 |
| *2. General Constr.(Composite) | 4.4 | 4.6 | -0.4 | 2.1 | 3.2 | 1.8 | 2.1 | 2.1 | 1.9 | 1.9 | 1.9 | 1.9 |
| Labour | 2.4 | 1.4 | 4.6 | 3.2 | 2.3 | | | | | | | |
| Materials | 6.0 | 7.3 | -4.2 | 1.1 | 3.9 | | | | | | | |
| 3. M.H. long-term Cdn interest rate | 5.71 | 5.65 | 5.75 | 5.27 | 4.64 | 4.15 | 4.30 | 4.85 | 5.55 | 5.95 | 6.15 | 6.30 |
| 4. Interest Capitilization Rate | | | | | | 12/13 | 13/14 | 14/15 | 15/16 | 16/17 | 17/18 | 18/19 |
| | | | | | | 6.6 | 6.2 | 6.3 | 6.3 | 6.3 | 6.3 | 6.2 |
| | 19/20 | 20/21 | 21/22 | 22/23 | 23/24 | 24/25 | 25/26 | 26/27 | 27/28 | 28/29 | 29/30 | 30/31 |
| | 6.4 | 6.7 | 6.3 | 6.3 | 6.3 | 6.3 | 6.3 | 6.3 | 6.3 | 6.3 | 6.3 | 6.3 |
| 5. Weighted Average Cost of Capital (%) | | | | | | <---------- 7.05 ----------> | | | | | | |
| *6. Consumer Price Index | | | | | | | | | | | | |
| MbCPI | 1.9 | 2.2 | 0.6 | 1.0 | 2.8 | 1.7 | 1.8 | 1.8 | 1.8 | 1.8 | 1.9 | 1.9 |
| CdnCPI | 2.1 | 2.2 | 0.4 | 2.0 | 2.8 | 1.8 | 2.1 | 2.1 | 1.9 | 1.9 | 1.9 | 1.9 |
| 7. Real Weighted Avg. Cost of Capital (7.05 - 1.9)/1.019 (%) | | | | | | <---------- 5.05 ----------> | | | | | | |
| 8. Real Hurdle Rates for Project Evaluation (minimum % rates of return) | | | | | | <---------- 5.05 to 15+ ----------> | | | | | | |
| *9. GDP Price Deflator | | | | | | | | | | | | |
| U.S. | 2.6 | 2.0 | 0.9 | 1.5 | 2.1 | 1.6 | 1.8 | 2.0 | 1.8 | 1.8 | 1.8 | 1.8 |
| Cdn. | 3.3 | 2.9 | -0.8 | 2.8 | *3.2* | 1.9 | 2.0 | 2.2 | 1.8 | 1.8 | 1.8 | 1.8 |
| 10. U.S. - Cdn. Exchange Rate (C$/US$) | 1.03 | 1.13 | 1.09 | 1.02 | 0.99 | 1.00 | 0.99 | 1.02 | 1.03 | 1.04 | 1.04 | 1.04 |

* Represents current fiscal year over previous fiscal year, % change

Item 1 Historical: Model based on Keeyask costs.
Includes both Statistics Canada and Bureau of Labor Statistics indexes.

Item 2 Historical: Canadata Construction Cost Index - REED CONSTRUCTION DATA

Item 3 Average of 10 year and 30 year Canadian long bond rates plus credit spread plus Provincial guarantee fee; Historical - Bloomberg actuals provided by Manitoba Hydro Treasury.

Item 4 Provided by Financial Planning Department: interest capitalization rates based on projected embedded cost of debt.
The interest capitalization rate should only be used for budgeting purposes.

Item 5 Nominal Cost of Capital = 0.75 * MH LT Cdn. Interest Rate + 0.25 * Imputed Cost of Equity
= 0.75(6.30) + 0.25(6.30 + 3) = 7.05
where a 3% premium is added to the MH LT Cdn Interest rate to impute a value for equity.

Item 6 Historical: Statistics Canada - *The Consumer Price Index - 62-001- X*,
Table 1 & Table 3

Item 7 (Nominal Cost of Capital - MbCPI)/(1 + (MbCPI/100)) - This is rounded to 5.05%

Item 8 See Application and Derivation of Hurdle Rates (G911-4) for further information

Item 9 Historical Statistics Canada - National Income and Expenditure Accounts - Table 30
U.S. Bureau of Economic Analysis - National Accounts Data - Table 5

Item 10 Historical: Bank of Canada Weekly Financial Statistics
Exchange rates reflect average for the fiscal year.
Exchange rate at March 31 2013 is projected to be 1.00.

** Projected as per Economic Outlook 2012 - Spring 2012 (EO12-1) & **Fall 2012 Update**; forecasts of items 3,6, 9 and 10 are based on a consensus view from surveys of private sector forecasters.

*Note: The italicized items are preliminary*

**EFFECTIVE** May 11 2012
RE-ISSUED September 11 2012
**RE-ISSUED October 11 2012**

Executive Committee Minute # **1415.03**

Subject: Projected Interest Rates
Number: G911-2
Revised: 2009 06 02

First screen of this guideline

Contact: For interpretation or further information on this policy, contact:
Economic Forecasting Consultant

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When evaluating and screening projects**,** apply the Weighted Average Cost of Capital (WACC), appropriately adjusted for the relative risk of the project (see Hurdle Rates G911-4)

Estimates of interest capitalized for Capital Project Budget Estimates included within Capital Project Justification (CPJ) submissions are calculated using rates based on the weighted average cost of debt (WACD) and the G911-1 projected long term Canadian debt rate. The rates are calculated and input to the SAP system by the Financial Planning Department.

Rates are applied to capital estimates as follows:

- Interest for the current month for a sub-project (Level 2 of the Work Breakdown Structure) is calculated on the opening month's balance of total accumulated net costs (including salvage material, salvage labour expense, customer contributions, holdbacks and outstanding accounts payable).

- Interest capitalization is to cease the month after plant additions are placed in-service

  Note: The in-service date for interest capitalization and depreciation purposes is the date Corporate Controller Division is notified that a project has been placed into service.

- No interest will be applied on expenditures that are in-service when purchased (for example equipment, tool and vehicle purchases).

- No interest will be applied on expenditures for projects with an expected duration of one month or less.

Subject: Projected Exchange Rate
Number: G911-3
Revised: 2009 06 02

First screen of this guideline

Contact: For interpretation or further information on this policy, contact:
Economic Forecasting Consultant

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The market U.S. exchange rate is forecast in the schedule of Projected Escalation, Interest and Exchange Rates (G911-1) and is also provided by Economic Analysis Department. This rate should be used for the evaluation of new transactions**.**

Example 1: New long term export sales to the United States—forecast revenues should be converted at the market rate in the Projected Escalation, Interest and Exchange Rates schedule, to make an economic evaluation of revenues as compared to costs in Canadian dollars.

Example 2: Short term transaction—current exchange rates should be applied when comparing a Canadian sale or purchase option to the U.S. option.

Example 3: Bid evaluations—current market values should be applied so that foreign bids can be assessed on a common dollar basis with Canadian bids.

Treasury Division should be consulted about the exchange rates to be used or for questions on daily or monthly market exchange rates (as for examples 2 and 3) or on the Exposure Management Program.

Reporting Revenues for the Integrated Financial Forecast (IFF)—U.S. revenue stream will initially be projected at the Cdn./U.S. market exchange rate. Firm revenues required to hedge U.S. dollar outflows may subsequently be revalued at the historical cost of existing $U.S. designated debt issues.

Subject: Hurdle Rates
Number: G911-4
Revised: 2012 10 18

First screen of this guideline

Contact: For interpretation or further information on this policy, contact:
Economic Forecasting Consultant

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Manitoba Hydro will maintain hurdle rates for purposes of evaluating the economics of investment decisions and project proposals. The hurdle rates used in the economic analyses will reflect the degrees of risk deemed to be inherent in the associated cash flows and will be categorized as:

- low risk
- low to medium risk, or
- medium to high risk

E.C 1009.05

**Application and Derivation of Hurdle Rates**

Capital expenditures undertaken by Manitoba Hydro are for reliability, safety, contractual, regulatory and environmental obligations and the general obligations to serve, or are undertaken for economic reasons. To evaluate the economics of a project, Manitoba Hydro utilizes business case principles involving the techniques of discounted cash flow (DCF), net present value (NPV) or internal rate of return (IRR).

See the following:

1. Background
2. Derivation of Hurdle Rates
3. Application of Hurdle Rates

Benchmark Hurdle Rates Classifications

- Low Risk
- Low to Medium Risk
- Medium to High Risk

**1. Background**

Three forms of economic analysis are generally used in investment decisions. The choice of which one to use is made by the analyst based on the type of project. The three forms are as follows:

1. Cost/benefit analysis is used to determine if a project is economically viable. If the benefits of the project are greater than the costs over the analysis period, considering the time value of money, the project is economically viable and has a positive cost/benefit.

2. Least cost analysis is used to determine the least cost approach given a number of available alternatives. The costs of each alternative are compared on a consistent basis over the analysis period, taking into account the time value of money, in an effort to determine the least cost alternative.

3. Internal Rate of Return (IRR) Analysis

In these analyses, Manitoba Hydro uses risk adjusted hurdle rates to discount future revenues and costs and determine whether the resulting NPV is positive. A hurdle rate is defined as the minimum expected rate of return that would be acceptable to justify making the investment. Generally, the starting point for development of a hurdle rate is the weighted average cost of capital (WACC), that is, the company's overall cost of financing. Depending on the type of project to be evaluated, a further risk premium can be added beyond that which is incorporated in the WACC to recognize additional uncertainty in future cash flows.

## 2. Derivation of Hurdle Rates

Manitoba Hydro's overall WACC is calculated using the cost of debt and the imputed rate for equity which are then weighted by Manitoba Hydro's target capital structure of 75% debt and 25% equity. The cost of debt is the forecast interest rate on the Government of Canada long term (10 year+) bond yield, plus provincial-federal borrowing spread and the provincial guarantee fee. The imputed cost of equity is calculated based on the fact that regulated investor owned utilities receive a regulated return on equity which is approximately 3% higher than the current market cost of new long term debt.

Therefore, Manitoba Hydro's WACC is calculated as follows:

WACC = (Cost of Debt x 75%) + (Imputed Cost of Equity x 25%)

WACC is usually used to assess investments in Manitoba Hydro's core business mix, that is, generation, transmission and distribution for domestic markets along with the types of export business in which the corporation has historically engaged. If a project falls outside of these core activities or has an unusual degree of risk, then the hurdle rate would be greater than WACC.

#### Risk Accounted for Outside of the Hurdle Rate

The selection of an appropriate discount rate depends on the risk associated with the cash flow projections. If future anticipated cash flows for a project have already been adjusted to reflect a degree of uncertainty, or if risk has been accounted for by some other means, then a lower risk premium would need to be incorporated in the applicable hurdle rate.

## 3. Application of Hurdle Rates

Hurdle rates are applied to arrive at a quantitative determination of a project's relative acceptability. However, the economic evaluation of a project or investment is only one component in determining whether to proceed. Other factors such as ensuring the safety and reliability of the system, customer service or operational efficiency are also considered. The weighting of these components may vary for each project or investment . Therefore, a project with a positive or negative NPV may or may not be approved depending on the significance of these other components.

As a general guideline, the company provides benchmark hurdle rates classified as low, medium and high risk investments or projects. These benchmark rates (in real terms) are demarcated by 5.05%, 10% and 15%+ for low, medium and high risk projects, respectively. In practice, each cash flow component will have varying levels of risk specific to the nature of that project. Therefore the risk classification of certain projects may not precisely equal one of the benchmark categories but instead fall within the range of the guideline rates provided.

Following is a description of these guideline categories together with examples. The examples are not intended to be all inclusive but rather are illustrative indications. As noted above, the hurdle rate is partly dependent on the degree to which risk has been recognized in the cash flow projections for the specific investment and is therefore not necessarily based on the type of project. For assistance in determining the appropriate risk adjusted rate for any project, departments should contact the Economic Analysis Department or Financial Planning Department. Where a hurdle rate other than at the top end of the range in each of the following risk categories is selected, Executive approval is required.

### Benchmark Hurdle Rate Classifications

#### Low Risk (5.05%)

A project with a low level of risk is defined as one which belongs in Manitoba Hydro's core business mix, that is, generation, transmission and distribution for domestic markets along with the types of export business in which the corporation has historically engaged. Such projects would be evaluated using WACC, that is, a real discount/hurdle rate of 5.05%.

General examples include, but are not limited to:

- projects required to meet safety, environmental or regulatory standards
- mandatory expenditures to maintain operational integrity of the system
- cost minimization/operational efficiency projects
- power resource projects (for example, demand side management, supply side enhancements and new generation) undertaken mainly to meet Manitoba Hydro's obligation to service domestic load or exports under existing contracts, and with minimal challenges and uncertainties

**Low to Medium Risk (greater than 5.05% up to 10%)**

A project that would be classified as ranging from low to medium risk is defined as one which belongs in Manitoba Hydro's core business mix (as defined for low risk), but which presents additional challenges and uncertainties. To recognize this exposure, a real discount/hurdle rate in the range of greater than 5.05% up to 10% is required.

General examples include, but are not limited to:

- certain customer service and joint ventures for utility services
- power loss reduction projects
- Manitoba Hydro International projects with guaranteed contracts
- power resource projects (for example, demand side management, supply side enhancements and new generation) with typical challenges and uncertainties

**Medium to High Risk (greater than 10% to 15%+)**

A project with a medium to high level risk is defined as one which does not belong in Manitoba Hydro's core business mix or which presents significant additional challenges and uncertainties. To recognize this exposure, a real discount/hurdle rate in the range of greater than 10% to 15%+ is required.

General examples include, but are not limited to:

- certain projects with highly uncertain cash flows which may be offered to Manitoba Hydro International
- major initiatives to gain new sources of revenue
- investments in new technology not directly related to core business

- power resource projects (for example, demand side management, supply side enhancements and new generation) with atypically high challenges and uncertainties

# Composite Index Matrix for Escalating Historical Cost Estimates (G911-5)

Based on escalation rates from Item #1 of G911-1

| | 75/76 | 76/77 | 77/78 | 78/79 | 79/80 | 80/81 | 81/82 | 82/83 | 83/84 | 84/85 | 85/86 | 86/87 | 87/88 | 88/89 | 89/90 | 90/91 | 91/92 | 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 | 06/07 | 07/08 | 08/09 | 09/10 | 10/11 | 11/12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| % chge | 13.4 | 10.0 | 6.8 | 7.8 | 8.8 | 9.3 | 12.8 | 7.6 | 5.7 | 3.0 | 2.4 | 1.7 | 4.3 | 6.2 | 5.4 | 4.0 | -0.5 | 0.1 | 3.8 | 5.3 | 3.9 | 3.2 | 4.2 | 3.1 | 4.5 | 4.1 | -0.5 | 3.3 | 3.3 | 7.8 | 6.6 | 5.9 | 5.2 | 6.1 | -4.0 | 5.8 | 5.1 |
| 75/76 | 1.00 | 1.10 | 1.17 | 1.27 | 1.38 | 1.51 | 1.70 | 1.83 | 1.93 | 1.99 | 2.04 | 2.07 | 2.16 | 2.30 | 2.42 | 2.51 | 2.50 | 2.51 | 2.60 | 2.74 | 2.85 | 2.94 | 3.06 | 3.16 | 3.30 | 3.43 | 3.41 | 3.53 | 3.64 | 3.93 | 4.19 | 4.43 | 4.66 | 4.95 | 4.75 | 5.03 | 5.29 |
| 76/77 | | 1.00 | 1.07 | 1.15 | 1.25 | 1.37 | 1.54 | 1.66 | 1.76 | 1.81 | 1.85 | 1.88 | 1.96 | 2.09 | 2.20 | 2.29 | 2.28 | 2.28 | 2.36 | 2.49 | 2.59 | 2.67 | 2.78 | 2.87 | 3.00 | 3.12 | 3.10 | 3.21 | 3.31 | 3.57 | 3.81 | 4.03 | 4.24 | 4.50 | 4.32 | 4.57 | 4.81 |
| 77/78 | | | 1.00 | 1.08 | 1.17 | 1.28 | 1.45 | 1.56 | 1.64 | 1.69 | 1.73 | 1.76 | 1.84 | 1.95 | 2.06 | 2.14 | 2.13 | 2.13 | 2.21 | 2.33 | 2.42 | 2.50 | 2.61 | 2.69 | 2.81 | 2.92 | 2.91 | 3.00 | 3.10 | 3.35 | 3.57 | 3.77 | 3.97 | 4.21 | 4.05 | 4.28 | 4.50 |
| 78/79 | | | | 1.00 | 1.09 | 1.19 | 1.34 | 1.44 | 1.53 | 1.57 | 1.61 | 1.64 | 1.71 | 1.81 | 1.91 | 1.99 | 1.98 | 1.98 | 2.05 | 2.16 | 2.25 | 2.32 | 2.42 | 2.49 | 2.60 | 2.71 | 2.70 | 2.78 | 2.88 | 3.10 | 3.31 | 3.50 | 3.68 | 3.91 | 3.75 | 3.97 | 4.18 |
| 79/80 | | | | | 1.00 | 1.09 | 1.23 | 1.33 | 1.40 | 1.44 | 1.48 | 1.50 | 1.57 | 1.67 | 1.76 | 1.83 | 1.82 | 1.82 | 1.89 | 1.99 | 2.07 | 2.13 | 2.22 | 2.29 | 2.39 | 2.49 | 2.48 | 2.56 | 2.64 | 2.85 | 3.04 | 3.22 | 3.39 | 3.59 | 3.45 | 3.65 | 3.84 |
| 80/81 | | | | | | 1.00 | 1.13 | 1.21 | 1.28 | 1.32 | 1.35 | 1.38 | 1.44 | 1.52 | 1.61 | 1.67 | 1.66 | 1.66 | 1.73 | 1.82 | 1.89 | 1.95 | 2.03 | 2.10 | 2.19 | 2.28 | 2.27 | 2.34 | 2.42 | 2.61 | 2.78 | 2.94 | 3.10 | 3.29 | 3.16 | 3.34 | 3.51 |
| 81/82 | | | | | | | 1.00 | 1.08 | 1.14 | 1.17 | 1.20 | 1.22 | 1.27 | 1.35 | 1.42 | 1.48 | 1.47 | 1.48 | 1.53 | 1.61 | 1.68 | 1.73 | 1.80 | 1.86 | 1.94 | 2.02 | 2.01 | 2.08 | 2.14 | 2.31 | 2.47 | 2.61 | 2.75 | 2.91 | 2.80 | 2.96 | 3.11 |
| 82/83 | | | | | | | | 1.00 | 1.06 | 1.09 | 1.11 | 1.13 | 1.18 | 1.26 | 1.32 | 1.38 | 1.37 | 1.37 | 1.42 | 1.50 | 1.56 | 1.61 | 1.67 | 1.73 | 1.80 | 1.88 | 1.87 | 1.93 | 1.99 | 2.15 | 2.29 | 2.43 | 2.55 | 2.71 | 2.60 | 2.75 | 2.89 |
| 83/84 | | | | | | | | | 1.00 | 1.03 | 1.05 | 1.07 | 1.12 | 1.19 | 1.25 | 1.30 | 1.30 | 1.30 | 1.35 | 1.42 | 1.47 | 1.52 | 1.58 | 1.63 | 1.71 | 1.78 | 1.77 | 1.82 | 1.89 | 2.03 | 2.17 | 2.30 | 2.41 | 2.56 | 2.46 | 2.60 | 2.74 |
| 84/85 | | | | | | | | | | 1.00 | 1.02 | 1.04 | 1.09 | 1.15 | 1.22 | 1.26 | 1.26 | 1.26 | 1.31 | 1.38 | 1.43 | 1.48 | 1.54 | 1.59 | 1.66 | 1.72 | 1.72 | 1.77 | 1.83 | 1.97 | 2.10 | 2.23 | 2.34 | 2.49 | 2.39 | 2.53 | 2.66 |
| 85/86 | | | | | | | | | | | 1.00 | 1.02 | 1.06 | 1.13 | 1.19 | 1.23 | 1.23 | 1.23 | 1.28 | 1.34 | 1.40 | 1.44 | 1.50 | 1.55 | 1.62 | 1.68 | 1.68 | 1.73 | 1.79 | 1.93 | 2.06 | 2.18 | 2.29 | 2.43 | 2.33 | 2.47 | 2.59 |
| 86/87 | | | | | | | | | | | | 1.00 | 1.04 | 1.11 | 1.17 | 1.21 | 1.21 | 1.21 | 1.26 | 1.32 | 1.37 | 1.42 | 1.48 | 1.52 | 1.59 | 1.66 | 1.65 | 1.70 | 1.76 | 1.90 | 2.02 | 2.14 | 2.25 | 2.39 | 2.29 | 2.43 | 2.55 |
| 87/88 | | | | | | | | | | | | | 1.00 | 1.06 | 1.12 | 1.16 | 1.16 | 1.16 | 1.20 | 1.27 | 1.32 | 1.36 | 1.42 | 1.46 | 1.53 | 1.59 | 1.58 | 1.63 | 1.69 | 1.82 | 1.94 | 2.05 | 2.16 | 2.29 | 2.20 | 2.33 | 2.45 |
| 88/89 | | | | | | | | | | | | | | 1.00 | 1.05 | 1.10 | 1.09 | 1.09 | 1.13 | 1.19 | 1.24 | 1.28 | 1.33 | 1.37 | 1.44 | 1.49 | 1.49 | 1.54 | 1.59 | 1.71 | 1.82 | 1.93 | 2.03 | 2.16 | 2.07 | 2.19 | 2.30 |
| 89/90 | | | | | | | | | | | | | | | 1.00 | 1.04 | 1.03 | 1.04 | 1.08 | 1.13 | 1.18 | 1.21 | 1.27 | 1.30 | 1.36 | 1.42 | 1.41 | 1.46 | 1.51 | 1.62 | 1.73 | 1.83 | 1.93 | 2.05 | 1.97 | 2.08 | 2.19 |
| 90/91 | | | | | | | | | | | | | | | | 1.00 | 1.00 | 1.00 | 1.03 | 1.09 | 1.13 | 1.17 | 1.22 | 1.25 | 1.31 | 1.36 | 1.36 | 1.40 | 1.45 | 1.56 | 1.67 | 1.76 | 1.85 | 1.97 | 1.89 | 2.00 | 2.10 |
| 91/92 | | | | | | | | | | | | | | | | | 1.00 | 1.00 | 1.04 | 1.09 | 1.14 | 1.17 | 1.22 | 1.26 | 1.32 | 1.37 | 1.36 | 1.41 | 1.46 | 1.57 | 1.67 | 1.77 | 1.86 | 1.98 | 1.90 | 2.01 | 2.11 |
| 92/93 | | | | | | | | | | | | | | | | | | 1.00 | 1.04 | 1.09 | 1.14 | 1.17 | 1.22 | 1.26 | 1.32 | 1.37 | 1.36 | 1.41 | 1.45 | 1.57 | 1.67 | 1.77 | 1.86 | 1.98 | 1.90 | 2.01 | 2.11 |
| 93/94 | | | | | | | | | | | | | | | | | | | 1.00 | 1.05 | 1.09 | 1.13 | 1.18 | 1.21 | 1.27 | 1.32 | 1.31 | 1.36 | 1.40 | 1.51 | 1.61 | 1.70 | 1.79 | 1.90 | 1.83 | 1.93 | 2.03 |
| 94/95 | | | | | | | | | | | | | | | | | | | | 1.00 | 1.04 | 1.07 | 1.12 | 1.15 | 1.20 | 1.25 | 1.25 | 1.29 | 1.33 | 1.43 | 1.53 | 1.62 | 1.70 | 1.81 | 1.74 | 1.84 | 1.93 |
| 95/96 | | | | | | | | | | | | | | | | | | | | | 1.00 | 1.03 | 1.07 | 1.11 | 1.16 | 1.20 | 1.20 | 1.24 | 1.28 | 1.38 | 1.47 | 1.56 | 1.64 | 1.74 | 1.67 | 1.77 | 1.86 |
| 96/97 | | | | | | | | | | | | | | | | | | | | | | 1.00 | 1.04 | 1.07 | 1.12 | 1.17 | 1.16 | 1.20 | 1.24 | 1.34 | 1.43 | 1.51 | 1.59 | 1.69 | 1.62 | 1.71 | 1.80 |
| 97/98 | | | | | | | | | | | | | | | | | | | | | | | 1.00 | 1.03 | 1.08 | 1.12 | 1.12 | 1.15 | 1.19 | 1.28 | 1.37 | 1.45 | 1.52 | 1.62 | 1.55 | 1.64 | 1.73 |
| 98/99 | | | | | | | | | | | | | | | | | | | | | | | | 1.00 | 1.04 | 1.09 | 1.08 | 1.12 | 1.15 | 1.25 | 1.33 | 1.41 | 1.48 | 1.57 | 1.51 | 1.59 | 1.68 |
| 99/00 | | | | | | | | | | | | | | | | | | | | | | | | | 1.00 | 1.04 | 1.04 | 1.07 | 1.11 | 1.19 | 1.27 | 1.35 | 1.42 | 1.50 | 1.44 | 1.53 | 1.60 |
| 00/01 | | | | | | | | | | | | | | | | | | | | | | | | | | 1.00 | 1.00 | 1.03 | 1.06 | 1.15 | 1.22 | 1.29 | 1.36 | 1.44 | 1.39 | 1.47 | 1.54 |
| 01/02 | | | | | | | | | | | | | | | | | | | | | | | | | | | 1.00 | 1.03 | 1.07 | 1.15 | 1.23 | 1.30 | 1.37 | 1.45 | 1.39 | 1.47 | 1.55 |
| 02/03 | | | | | | | | | | | | | | | | | | | | | | | | | | | | 1.00 | 1.03 | 1.11 | 1.19 | 1.26 | 1.32 | 1.40 | 1.35 | 1.43 | 1.50 |
| 03/04 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | 1.00 | 1.08 | 1.15 | 1.22 | 1.28 | 1.36 | 1.30 | 1.38 | 1.45 |
| 04/05 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | 1.00 | 1.07 | 1.13 | 1.19 | 1.26 | 1.21 | 1.28 | 1.35 |
| 05/06 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | 1.00 | 1.06 | 1.11 | 1.18 | 1.14 | 1.20 | 1.26 |
| 06/07 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | 1.00 | 1.05 | 1.12 | 1.07 | 1.13 | 1.19 |
| 07/08 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | 1.00 | 1.06 | 1.02 | 1.08 | 1.13 |
| 08/09 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | 1.00 | 0.96 | 1.02 | 1.07 |
| 09/10 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | 1.00 | 1.06 | 1.11 |
| 10/11 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | 1.00 | 1.05 |
| 11/12 | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | 1.00 |

An example:

$250 million estimate made in 1999/00 and escalated to 2011/12.

Base price in 1999/00 = $250 million

New Estimate in 2011/12 = $250 million * (2011/12 index) / (1999/00 index)

= $250 million * (1.60 / 1.00)

= $400 million

Note 1: Historical Hydro Project Index Matrix to be updated annually each Spring

**Note 2: Historical values may change, due to Statistics Canada revisions associated with technology changes and new items included in index**

**SUBJECT: Keeyask**

**REFERENCE: CAC/MH 1-008**

**PREAMBLE:** The response states that 25% of the capital cost of the Keeyask generating station is forecast to be financed through equity by partners.

**QUESTION:**

What is Manitoba Hydro's assumed share of the total equity invested in the project? Please provide both a dollar value and a percentage value (i.e. of the 25% total how many percentage points are Manitoba Hydro's), reconciling both with the $6.2 B total capital cost.

**RESPONSE:**

The NFAT financial evaluation assumes that the KCN invest in the preferred ownership arrangement. Under this arrangement, the KCN will invest $25 million plus preferred distributions from first unit in-service to Joint Keeyask Development Agreement (JKDA) final close and the percentage ownership will be a function of the total dollar value invested and the capital cost of the Keeyask project. Based on the NFAT reference scenario capital cost of $5.7 billion, Manitoba Hydro’s equity investment will be $1.3 billion or approximately 98%. Based on the CEF12 capital cost of $6.2 billion, Manitoba Hydro’s equity investment in the project will be $1.4 billion or approximately 98%.

Under a common equity arrangement, the KCN may invest up to 25% of the total 25% equity in the Keeyask Project and Manitoba Hydro’s investment will be at least 75%.

The following schedule shows the capital structure of KHLP and calculations of owners’ equity based on the different project capital costs.

KHLP Capital Structure
($ Millions)

| | | NFAT Reference Scenario | CEF12 |
|---|---|---|---|
| Total Project In-Service Cost | | 5,711 | 6,220 |
| **Less:** | | - | - |
| Transmission | | (203) | (202) |
| Interest on MH Equity | | (174) | (196) |
| KHLP Generating Station In-Service Cost | | 5,334 | 5,822 |
| | | | |
| Total Project Debt | 75% | 4,001 | 4,366 |
| Total Project Equity | 25% | 1,334 | 1,455 |
| | | | |
| Preferred Arrangement: | | | |
| KCN Equity Investment | | 32 | 30 |
| KCN Ownership Percentage | | 2.37% | 2.07% |
| | | | |
| MH Equity Investment | | 1,302 | 1,425 |
| MH Ownership Percentage | | 97.63% | 97.93% |
| | | | |
| Common Arrangement: | | | |
| KCN Equity Investment | | 333 | 364 |
| KCN Ownership Percentage | | 25% | 25% |
| | | | |
| MH Equity Investment | | 1,000 | 1,092 |
| MH Ownership Percentage | | 75% | 75% |

**SUBJECT: Keeyask**

**REFERENCE: CAC/MH 1-008**

**PREAMBLE:** The response states that 25% of the capital cost of the Keeyask generating station is forecast to be financed through equity by partners.

**QUESTION:**

Is the capitalized interest of $0.85 B (Chapter 2, Table 2.2) calculated based on the total capital spending for the project or just that portion that is assumed to be debt-financed?

**RESPONSE:**

The capitalized interest in the amount of $0.85 billion represents the interest on the debt financed portion of the Keeyask Generating Station reflected as interest capitalized on the KHLP financial statements and then consolidated with Manitoba Hydro electric operations.

**SUBJECT: Keeyask**

**REFERENCE: CAC/MH 1-008**

**PREAMBLE:** The response states that 25% of the capital cost of the Keeyask generating station is forecast to be financed through equity by partners.

**QUESTION:**

If based on the total, why is there any need to add in an additional amount for "Interest on MH Equity"?

**RESPONSE:**

Manitoba Hydro will finance the 75% debt portion of the Keeyask Generating Station capital cost to KHLP. The interest capitalized on this portion is reflected as KHLP interest capitalized. In addition, Manitoba Hydro will finance its share of the equity investment in KHLP and the associated interest capitalized is reflected in the Manitoba Hydro's electric operations. When KHLP is consolidated with Manitoba Hydro electric operations, the interest capitalized on the KHLP debt portion ($0.788 billion under the reference scenario) and the interest capitalized on Manitoba Hydro's equity portion ($0.174 billion) are added together ($0.962 billion) to reflect the approximate 98% share of the capital cost Manitoba Hydro is financing (excluding the equity amount contributed by the KCN).

Please also see Manitoba Hydro's responses to CAC/MH II-006(a) and (b).

**SUBJECT: Keeyask**

**REFERENCE: CAC/MH 1-008**

**PREAMBLE:** The response states that 25% of the capital cost of the Keeyask generating station is forecast to be financed through equity by partners.

**QUESTION:**

If not based on the total capital investment cost, is the "Interest on MH Equity" calculated based on the total 25% equity assumed or just on Manitoba Hydro's share of the total equity (i.e., excluding the equity contributed by First Nation partners)? As part of the response, please explain and provide the rationale for the treatment.

**RESPONSE:**

Please see the responses to CAC/MH II-006 (a) to (c).

**SUBJECT: Keeyask**

**REFERENCE: CAC/MH I-008**

**QUESTION:**

Is the $6.2 B figure the value that is used in the Financial Evaluations as the in-service cost of Keeyask (Chapter 11)?

**RESPONSE:**

The financial evaluation incorporates nine different Keeyask capital costs based on all possible combinations of low, reference and high base capital costs with low, reference and high escalation and interest rates. Under these scenarios, Keeyask capital costs range from $5.0 billion to $6.7 billion and the CEF12 Keeyask capital cost of $6.2 billion is a value within that range but is not a specific capital cost used in the financial evaluation. The following table shows the Keeyask capital costs under each of the nine capital cost scenarios used in the financial evaluation.

**Preferred Development Plan**
**Keeyask 2019-20 In-Service Cost**
**Billions of Dollars**

| Base Capital Cost Scenario | Economic Indicator Scenario | In-Service Cost |
|---|---|---|
| Low | Low | 5.014 |
| Low | Ref | 5.309 |
| Ref | Low | 5.396 |
| Low | High | 5.640 |
| Ref | Ref | 5.711 |
| High | Low | 5.979 |
| Ref | High | 6.075 |
| High | Ref | 6.334 |
| High | High | 6.740 |

**REFERENCE: CAC/MH I-008**

**SUBJECT: Keeyask**

**QUESTION:**

If not, what is the value used and why is it different?

**RESPONSE:**

Please see Manitoba Hydro's response to CAC/MH II-007(a).

## SUBJECT: Keeyask

## REFERENCE: CAC/MH I-008

## QUESTION:

Is "Interest on MH Equity" included in the in-service Keeyask capital cost for purposes of the financial evaluations and why is its inclusion/exclusion appropriate?

## RESPONSE:

Interest on Manitoba Hydro’s equity portion is included in the NFAT financial evaluation. The combined interest capitalization on the KHLP debt portion and Manitoba Hydro’s equity portion (excluding the KCN equity contribution) represents the interest charges on the total amount Manitoba Hydro is financing on the Keeyask project. Please also see the responses to CAC/MH II-006(a)-(d).

**SUBJECT: Keeyask**

**REFERENCE: CAC/MH I-010**

**QUESTION:**

Please confirm that the "dollars spent to March 31, 2012" are captured in the IFF12 forecast balance sheets and, similarly, in the forecast balance sheets provided in Appendix 11.4.

**RESPONSE:**

Confirmed, costs spent to March 31, 2012 are included in the opening balance of Construction in Progress in each development plan and scenario in Appendix 11.4.

**SUBJECT: Keeyask**

**REFERENCE: CAC/MH I-010**

**QUESTION:**

If not, how are these costs accounted for in the financial evaluations?

**RESPONSE:**

Please see Manitoba Hydro's response to CAC/MH II-008.

**SUBJECT: Keeyask**

**REFERENCE: CAC/MH I-010 and CAC/MH I-134**

**QUESTION:**

Was the Labour Reserve for Keeyask also excluded from the economic evaluations? Also, was the escalation reserve included or excluded for purposes of the economic evaluations?

**RESPONSE:**

Please refer to Manitoba Hydro's response to PUB/MH II-447 for an explanation of where labour reserve and the respective escalation reserve on the labour reserve was and was not included in the NFAT economic and financial evaluations. The escalation reserve, as described in Appendix 2.4 of the NFAT submission, was applied to the capital cost estimates for Keeyask.

**SUBJECT: Conawapa**

**REFERENCE: CAC/MH I-013**

**QUESTION:**

Why was the Labour Reserve excluded from the capital costs of Conawapa used for purposes of the economic evaluations?

**RESPONSE:**

Please refer to Manitoba Hydro's response to PUB/MH II-447.

## SUBJECT: Transmission Reliability

## REFERENCE: CAC/MH I-014 a

## QUESTION:

Why is the criteria the largest single piece of equipment as opposed to say the loss of the entire Bipole III line due to a single event such as adverse weather?

## RESPONSE:

The loss of a largest single piece, i.e. the HVdc valve group, is the most frequent outage that occurs in  Manitoba Hydro's HVDC operation experience and similar experience is expected for Bipole III operation. Therefore, the valve outge is considered when evaluating the firm transfer capability of HVdc system. The performance of the three-bipole system meets the NERC reliability performance standard,  including  the contingency of  Bipole III loss.

**SUBJECT: Transmission Reliability**

**REFERENCE: CAC/MH I-014a , CAC/MH I-18b**

**QUESTION:**

Alternatively, if a single piece of equipment out of service is the relevant consideration then why aren't the 900 MW and 1,000 MW HVDC poles (noted in page 10 of the attachment to CAC/MH 1-051) the relevant consideration?

**RESPONSE:**

As indicated in the response to CAC/MH II-13a, the Manitoba Hydro system can meet the NERC reliability standard for the loss of a 2000MW bipole, so the loss of a 900-1000MW pole is not a reliability concern for the Manitoba Hydro system. A pole loss has been studied historically in addition to valve losses and bipole losses. The loss of 900-1000MW pole is a low probability event (< 1%) as stated in Appendix 13 of the NFAT submission, therefore it is not considered to be an economically attractive option to cover for this loss with additional spare HVdc capability when evaluating the firm transfer capability of the HVdc system.

**SUBJECT: Capital Costs**

**REFERENCE: CAC/MH 1-017b and CAC/MH 1-018b**

**QUESTION:**

Please confirm that the $331 M cost for the Manitoba portion was used in the NFAT economic evaluations and whether it was also used for the NFAAT financial evaluations?

**RESPONSE:**

As stated in Manitoba Hydro's response to CAC/MH I-018b, the $331 million cost for the Manitoba portion of the 750 MW US interconnection was the in-service cost which includes interest and escalation.

The base estimate of $267 million (2012$) was used in the NFAT Economic evaluations. Adding interest and escalation to this base estimate yields the $331 million in-service cost.

The $331 million in-service cost was used in the NFAT financial evaluations.

**SUBJECT: Capital Costs**

**REFERENCE: CAC/MH I-018b**

**QUESTION:**

Was the updated capital cost of $350 M incorporated into the 2013 Update (Chapter 12)? If not, why not?

**RESPONSE:**

The increase in estimate from $331 million to $350 million reflects an updated in-service cost estimate for the Manitoba portion of the 750 MW US interconnection. This information was not available for inclusion in the economic analysis for the 2013 Update (Chapter 12). Please refer to Manitoba Hydro's response to CAC/MH I-018b.

## SUBJECT: Partnership Agreements

## REFERENCE: CAC/MH I-022a and CAC/MH I-024

## QUESTION:

For purposes of the financial projections, what percentage of KCN ownership interest was assumed (per CAC/MH 1-024)?

## RESPONSE:

As indicated in the response to MIPUG/MH I-017(a), the percentage of KCN equity ownership ranges from 1.9% to 2.5% depending upon the capital cost scenario. Under all scenarios, the KCN are projected to invest $25 million plus preferred distributions from first unit in-service to final close and the percentage ownership will be a function of the total dollar value invested and the capital cost of the Keeyask project. The response to CAC/MH II-006(a) provides the calculation of the KCN ownership interest in terms of total dollar value as well as percentage interest under the reference scenario.

## SUBJECT: Partnership Agreements

## REFERENCE: CAC/MH I-024

## QUESTION:

Please provide the projected financial statement for the Keeyask Partnership of the first year that Keeyask is in-service all year and provide a schedule that sets out how the annual distribution for the preferred-unit partners would be calculated based on these results.

## RESPONSE:

Please see the response to CAC/MH II-076 for the KHLP projected operating statement.

The following schedule provides the calculation of the projected KCN Preferred Distribution for the 2022/23 fiscal year.

**KCN Preferred Distribution Calculation**
**Millions of Dollars**

| | | | **2022/23** |
|---|---|---|---|
| Keeyask Partnership Revenue | | | 293.004 |
| Marketing Risk Fee | | | (8.790) |
| Revenue Net of Marketing Risk Fee | | | 284.214 |
| | | | |
| **Less:** | | | |
| Amortization of Pre-Construction Capital Expenditures | | | (4.126) |
| Operating and Administration | | | (15.269) |
| Interest on Pre-Construction Costs | | | (17.740) |
| | | | |
| Adjusted Gross Revenue | | | 247.079 |
| | | | |
| **Share of Adjusted Gross Revenue:** | **% Share per 1% of KCN Ownership Interest** | **KCN Ownership Interest** | |
| Adjusted Gross Revenue $0 to $250 million | 0.8% | 2.37% | 4.685 |
| Adjusted Gross Revenue $250 million to $1 billion | 1.2% | 2.37% | - |
| Adjusted Gross Revenue > $1 billion | 1.6% | 2.37% | - |
| | | | |
| KCN Preferred Distribution | | | 4.685 |

## REFERENCE: Question CAC/MH I-022b

## QUESTION:

Does the non-controlling interest shown in the financial statements in Appendix 11.4 only reflect the preferred dividends projected to be paid to the KCN or does it include other items as well?

## RESPONSE:

The non-controlling interest shown in the financial statements in Appendix 11.4 also includes NCN's share of the projected net income or loss from the Wuskwatim Power Limited Partnership.

**SUBJECT: Partnership Agreements**

**REFERENCE: CAC/MH I-022 b)**

**QUESTION:**

If other items are included what are they and how will their values vary under the various scenarios?

**RESPONSE:**

The attached schedule shows the breakdown of non-controlling interest between NCN's 33% share of WPLP income and losses and preferred distributions to the KCN.

**Development Plan** **K19 Sales C25 750 MW**
**Scenario** **Economics:REF Rev:REF Cap:REF**

| **Fiscal Year Ending March 31** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** | **2033** | **2034** | **2035** | **2036** | **2037** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| NCN's Share (33%) of WPLP Net Income | (14) | (24) | (23) | (17) | (14) | (13) | (9) | (9) | (7) | (4) | (2) | 2 | 4 | 0 | 2 | 4 | 5 | 8 | 10 | 11 | 13 | 15 | 17 | 18 | 19 |
| KCN's Preferred Distributions before repayments | - | - | - | - | - | - | - | - | - | 5 | 5 | 5 | 5 | 5 | 5 | 6 | 6 | 6 | 6 | 7 | 7 | 7 | 7 | 7 | 7 |
| Non-Controlling Interest | (14) | (24) | (23) | (17) | (14) | (13) | (9) | (9) | (7) | 1 | 3 | 7 | 9 | 5 | 7 | 9 | 11 | 14 | 16 | 18 | 20 | 22 | 24 | 25 | 26 |

**Development Plan** **K19 Sales C25 750 MW**
**Scenario** **Economics:REF Rev:HIGH Cap:REF**

| **Fiscal Year Ending March 31** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** | **2033** | **2034** | **2035** | **2036** | **2037** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| NCN's Share (33%) of WPLP Net Income | (14) | (24) | (19) | (12) | (10) | (7) | (4) | (3) | 1 | 3 | 6 | 9 | 11 | 11 | 13 | 15 | 17 | 20 | 22 | 24 | 26 | 28 | 29 | 32 | 37 |
| KCN's Preferred Distributions before repayments | - | - | - | - | - | - | - | - | - | 7 | 7 | 8 | 8 | 9 | 9 | 9 | 9 | 10 | 10 | 11 | 11 | 11 | 12 | 13 | 13 |
| Non-Controlling Interest | (14) | (24) | (19) | (12) | (10) | (7) | (4) | (3) | 1 | 10 | 13 | 17 | 19 | 20 | 22 | 25 | 27 | 30 | 32 | 35 | 37 | 39 | 41 | 44 | 50 |

**Development Plan** **K19 Sales C25 750 MW**
**Scenario** **Economics:REF Rev:LOW Cap:REF**

| **Fiscal Year Ending March 31** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** | **2031** | **2032** | **2033** | **2034** | **2035** | **2036** | **2037** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| NCN's Share (33%) of WPLP Net Income | (14) | (24) | (27) | (21) | (19) | (18) | (13) | (14) | (16) | (13) | (11) | (6) | (4) | (11) | (10) | (8) | (7) | (4) | (3) | (1) | 1 | 3 | 5 | 4 | 0 |
| KCN's Preferred Distributions before repayments | - | - | - | - | - | - | - | - | - | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 4 | 4 | 4 | 4 | 4 | 3 | 3 |
| Non-Controlling Interest | (14) | (24) | (27) | (21) | (19) | (18) | (13) | (14) | (16) | (10) | (8) | (3) | (1) | (8) | (7) | (5) | (3) | (1) | 1 | 3 | 5 | 7 | 9 | 8 | 4 |

**Development Plan** **K19 Sales C25 750 MW**
**Scenario** **Economics:REF Rev:REF Cap:REF**

| **Fiscal Year Ending March 31** | **2038** | **2039** | **2040** | **2041** | **2042** | **2043** | **2044** | **2045** | **2046** | **2047** | **2048** | **2049** | **2050** | **2051** | **2052** | **2053** | **2054** | **2055** | **2056** | **2057** | **2058** | **2059** | **2060** | **2061** | **2062** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| NCN's Share (33%) of WPLP Net Income | 20 | 22 | 24 | 26 | 27 | 29 | 31 | 33 | 35 | 37 | 38 | 38 | 39 | 40 | 41 | 41 | 42 | 43 | 45 | 46 | 48 | 49 | 51 | 53 | 55 |
| KCN's Preferred Distributions before repayments | 8 | 8 | 8 | 8 | 9 | 9 | 9 | 10 | 10 | 10 | 10 | 11 | 11 | 11 | 11 | 12 | 12 | 12 | 13 | 13 | 13 | 13 | 14 | 14 | 14 |
| Non-Controlling Interest | 28 | 30 | 32 | 34 | 36 | 38 | 41 | 43 | 45 | 47 | 49 | 49 | 50 | 51 | 53 | 53 | 54 | 55 | 57 | 59 | 61 | 63 | 64 | 66 | 69 |

**Development Plan** **K19 Sales C25 750 MW**
**Scenario** **Economics:REF Rev:HIGH Cap:REF**

| **Fiscal Year Ending March 31** | **2038** | **2039** | **2040** | **2041** | **2042** | **2043** | **2044** | **2045** | **2046** | **2047** | **2048** | **2049** | **2050** | **2051** | **2052** | **2053** | **2054** | **2055** | **2056** | **2057** | **2058** | **2059** | **2060** | **2061** | **2062** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| NCN's Share (33%) of WPLP Net Income | 40 | 43 | 45 | 49 | 52 | 54 | 57 | 60 | 62 | 65 | 67 | 67 | 69 | 70 | 72 | 74 | 75 | 76 | 78 | 80 | 82 | 84 | 87 | 89 | 92 |
| KCN's Preferred Distributions before repayments | 13 | 13 | 15 | 15 | 15 | 16 | 17 | 17 | 18 | 18 | 18 | 19 | 19 | 19 | 20 | 20 | 21 | 21 | 22 | 22 | 22 | 23 | 23 | 24 | 24 |
| Non-Controlling Interest | 53 | 56 | 60 | 64 | 67 | 70 | 74 | 77 | 80 | 83 | 85 | 86 | 88 | 90 | 92 | 94 | 96 | 97 | 99 | 102 | 105 | 107 | 110 | 113 | 116 |

**Development Plan** **K19 Sales C25 750 MW**
**Scenario** **Economics:REF Rev:LOW Cap:REF**

| **Fiscal Year Ending March 31** | **2038** | **2039** | **2040** | **2041** | **2042** | **2043** | **2044** | **2045** | **2046** | **2047** | **2048** | **2049** | **2050** | **2051** | **2052** | **2053** | **2054** | **2055** | **2056** | **2057** | **2058** | **2059** | **2060** | **2061** | **2062** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| NCN's Share (33%) of WPLP Net Income | (0) | 1 | 2 | 2 | 3 | 4 | 5 | 7 | 8 | 9 | 9 | 8 | 8 | 9 | 9 | 10 | 10 | 11 | 12 | 12 | 13 | 14 | 15 | 16 | 18 |
| KCN's Preferred Distributions before repayments | 3 | 3 | 3 | 3 | 3 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 6 |
| Non-Controlling Interest | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 13 | 13 | 12 | 13 | 13 | 14 | 14 | 15 | 15 | 16 | 17 | 19 | 20 | 21 | 22 | 23 |

**SUBJECT: Partnership Agreements**

**REFERENCE: CAC/MH I-022b**

**QUESTION:**

If other items are also included, please provide the annual distribution of preferred dividends to KCN for the preferred development plan under the following cases:

i) Economic:REF/Rev:REF/Capital:REF;

ii) Economic:REF/Rev:HIGH/Capital:REF and

iii) Economics:REF/Rev:LOW/Capital:REF

**RESPONSE:**

Please see the response to CAC/MH II-019b.

## SUBJECT: Export Contract

## REFERENCE: CAC/MH I-027a

## QUESTION:

Unless otherwise agreed to in the sale arrangement, would these sales to MP and WPS normally trigger charges (under the Manitoba Hydro Tariff) that would be payable to Manitoba Hydro? If so, what are the current Manitoba Hydro Tariff charges for such service?

## RESPONSE:

Under normal conditions, Manitoba Hydro would earn Transmission Revenues under the Manitoba Hydro Open Access Transmission Tariff (OATT) for transmission services provided to Manitoba Hydro transmission customers. For Firm Point-to-Point electricity sales, Manitoba Hydro transmission service charges would be $4,673.29 $MW-MO (per megawatt for one month). This would include Schedule 1 - Scheduling, System Control and Dispatch Service; Schedule 2 - Reactive Supply and Voltage Control from Generation Sources Service; and Schedule 7 - Long-Term Firm and Short-Term Firm Point-to-Point Transmission Service.

The Coordination Agreement with MISO and Manitoba Hydro waives transmission service charges to encourage open access (to avoid transmission “pancaking” of tariff rates in multiple jurisdictions). The waiving of transmission charges is reciprocal and occurs in the following cases:

- MISO shall waive all transmission service charges for Point-to-Point Transmission Service involving service from a generating source located either inside or outside the ISO Tariff Zone to load in the Manitoba Hydro Zone.
- Manitoba Hydro shall waive all transmission service charges for Point-to-Point Transmission Service involving service from a generating source inside or outside the Manitoba Hydro Zone to a load that is located inside the ISO Tariff Zone.

Therefore, for electricity sales to Minnesota Power (MP) and Wisconsin Public Service Corporation (WPS) from Manitoba Hydro, the transmission service charges within Manitoba would be waived under the Coordination Agreement.

For electricity sales from MP and WPS to Manitoba Hydro, there would be no transmission service charges within Manitoba since there is no transfer pricing agreement. Manitoba Hydro Energy Marketing (the customer in this case) and Transmission are both owned by Manitoba Hydro.

## SUBJECT: Export Contract

## REFERENCE: CAC/MH I-027b

## QUESTION:

What are the current MISO Tariff charges for such service and what share would accrue to Manitoba Hydro?

## RESPONSE:

MISO posts the tariff rates on their public website, which are adjusted from time to time (and vary according to specific transaction). When Manitoba Hydro enters into a long term sale with an export customer, that company pays the MISO tariff fee. With respect to the new U.S. Interconnection, Manitoba Hydro has yet to determine whether it will be a registered Transmission Owner in MISO. As a result, it is not possible to say definitively whether it would share in any MISO revenues from the new transmission line as provided for under the MISO Tariff.

**SUBJECT: Export Markets**

**REFERENCE: CAC/MH I-033**

**QUESTION:**

Are the on-peak and off-peak price forecasts in Slide 33 meant to reflect on-peak and off-peak opportunity prices? If not, what do they represent and how does this differ from forecast on-peak and off-peak opportunity prices used in the economic and financial evaluations?

**RESPONSE:**

Manitoba Hydro notes that the Reference CAC/MH I-033 in turn references slide 33 of Appendix 3.1 which is Brattle's report "Long Term Price Forecast to Manitoba Hydro's Export Market in MISO" dated March 2013. Slide 33 contains forecasts of On-Peak and Off-Peak Energy prices on a chart labeled "Annual Average Energy and Capacity Prices".

The On-Peak and Off-Peak Energy forecasts on Slide 33 can be considered The Brattle Group's expectations for day-ahead market prices, under the specified scenario assumptions, for the MRO-west region (which includes Minn Hub) of MISO. Manitoba Hydro's surplus opportunity energy would generally be sold into the MISO Day Ahead market or sold under short term bilateral contracts at pricing based on the current short term expectations in the MISO Day Ahead Market.

The value of Capacity shown on the Annual Average Energy and Capacity Prices represents the annual value of Capacity divided by the 8760 hours (All Hours) in a year. For the purpose of preparing the electricity export price forecast, Manitoba Hydro allocates the annual value of Capacity over the 4170 hours in the On Peak period.

Manitoba Hydro applies the consensus On-Peak Energy Forecast when forecasting revenues from the export of on-peak opportunity energy. Off-peak opportunity energy is valued at the Off-Peak Energy price. In its forecast of opportunity revenues, Manitoba Hydro also accounts for additional value related to short-term forward sales and revenues from non flow related market transactions.

## SUBJECT: Export Markets

## REFERENCE: CAC/MH I-037 a) and PUB/MH I-235 b)

## QUESTION:

What rate(s) of inflation would have to be used in order to translate the constant 2013 U.S. in Figure 3.13 into nominal dollars over the period 2013-2034?

## RESPONSE:

The set of electricity price forecasts shown in Figure 3.13 in Chapter 3 of the NFAT submission are from the March 2013 report on "Long-Term Price Forecast for Manitoba Hydro's Export Market in MISO – The Brattle Group" as provided in Appendix 3.1 of the NFAT submission.

The US GDP Deflator inflation rates, as provided in page 1 of Appendix 11.2 of the NFAT submission, should be used to convert the 2013 US constant dollars to nominal dollars.

**SUBJECT: Load Forecast**

**REFERENCE: CAC/MH I-043 and CAC/MH I-047 b**

**QUESTION:**

Please confirm that by not accounting for non-persistence of savings achieved to date the 2027/2028 load forecast is understated by almost 500 GWh (per Figure 4.10).

**RESPONSE:**

Not confirmed. The starting year of the Load Forecast is based upon weather adjusted actual energy consumption. As the starting point is actual energy consumption, it is assumed to reflect all energy savings achieved to date due to past codes & standards and Power Smart program activity and, as no additional future adjustments are made to this base year consumption, the energy savings achieved to date is assumed to persist.

## SUBJECT: Load Forecast

## REFERENCE: CAC/MH I-043 and CAC/MH I-047 b

## QUESTION:

If not confirmed, please explain why and what, if any, understatement does exist.

## RESPONSE:

Please refer to Manitoba Hydro's response to CAC/MH II-026a.

**SUBJECT: Load Forecast**

**REFERENCE: CAC/MH I-048**

**QUESTION:**

Does the load forecast assume the introduction of any new codes/standards after 2027/28? If yes, what are they and when are they assumed to come into effect?

**RESPONSE:**

The load forecast does not assume the introduction of any new codes/standards after 2027/28.

**REFERENCE: CAC/MH I-075b**

**PREAMBLE:** The congestion component of the LMP at Manitoba Hydro Electric Board has been negative for most of the time since 2011.

**QUESTION:**

Will the Great Northern Transmission Line to be constructed by MP reduce the Congestion Component?

**RESPONSE:**

As noted in Chapter 6, Section 6.5.3 New Transmission Interconnection, "the new transmission interconnection is an international transmission line, with two distinct components – the Manitoba-Minnesota Transmission Project (MMTP) in Manitoba and the Great Northern Transmission Line (GNTL) in Minnesota. The interconnection would have an incremental transfer capability of 750 MW for both exports from and imports into Manitoba." Both components are required for the line to function.

Manitoba Hydro anticipates that in the future, under the preferred development plan, increased exports will be achieved on the larger interconnection with the 750 MW interconnection upgrade (i.e. Great Northern Transmission and the Manitoba Minnesota Transmission Project), and as a result the future relative congestion levels are not expected to change significantly from recent historic levels.

Also, as noted in the response to CAC/MH I-031, "In the future, Manitoba Hydro anticipates this regional transmission planning process will help minimize future congestion in the MISO market. However should Keeyask and Conawapa proceed without a new major interconnection, additional off-peak congestion at Minnesota Hub and at the MHEB LMP node can be expected as a significant proportion of the surplus energy that these projects would produce would have to sold in the off peak hours."

Some degree of a negative congestion component at the MHEB node is to be expected as Manitoba Hydro was a significant net exporter most times during the January 2011- August 2013 period as shown in the response to CAC/MH 1-075b. Net importing regions tend to have positive congestion components in their locational marginal prices while net exporting regions tend to have a negative congestion component.

**SUBJECT: Export Markets**

**REFERENCE: CAC/MH I- 075b**

**PREAMBLE:** The congestion component of the LMP at Manitoba Hydro Electric Board has been negative for most of the time since 2011.

**QUESTION:**

Will the proposed 500 MW Minnesota-Manitoba Transmission project (particularly the U.S. portion) further reduce the Congestion Component?

**RESPONSE:**

As explained in the response to CAC/MH I-031, Manitoba Hydro is not proposing to build a 750 kV, or a 500 MW interconnection. As indicated in Section 2.4 page 56 of the NFAT filing, "The proposed Manitoba-Minnesota Transmission Project is a 750 MW, 500 kV AC transmission line."

Please see Manitoba Hydro's response to CAC/MH II-030a.

## SUBJECT: Imports

## REFERENCE: CAC/MH I-086

## QUESTION:

With respect to column 5 in the Table provided, what was the off-peak transmission limit used to determine the values of Plans 4 and 14? In each case, please indicate how this limit was determined.

## RESPONSE:

As shown in Table 5.8 of the NFAT Business Case the firm transfer capability of the existing U.S. interconnection is 700 MW.

For Plan 4 (K19/Gas/250MW) the 250 MW U.S. interconnection is assumed for planning purposes to have a firm transfer capability for imports of 50 MW, bringing the total firm import capability to 750 MW.

For Plan 14 (K19/C25/750MW (WPS Sale & Inv)) the new US interconnection is assumed to have an import capability of 750MW. In the NFAT submission, for energy planning purposes Manitoba Hydro assumed the ability to import energy on the new interconnection on a guaranteed basis at 375 MWh/hr during the off-peak hours. When added to the existing interconnection, the total firm transmission service for planning purposes is 1075 MW.

## SUBJECT: Imports

## REFERENCE: CAC/MH I-094

## QUESTION:

Please explain why, under New Imports, the Capacity is shown as "Proposed" but the Dependable Energy is shown as "Contracted" and explain what the difference is between the two designations.

## RESPONSE:

The Supply and Demand Tables for the K19/C31/750MW development plan are shown on Pages 31 to 36 of Appendix 4.2.

The K19/C31/750MW development plan accommodates a six year deferral of the Conawapa G.S. through the additional import capability provided by the new interconnection.

The Proposed Imports for the 2025/26 through to the 2030/31 fiscal years in the New Power Resources section of the Winter Peak Capacity Supply and Demand Table reflect future capacity purchases that will be required to defer Conawapa. These capacity imports are classified as "Proposed" as there is no contract currently in place for these future purchases and it is assumed that the purchases will be made at some time in the future closer to the need date. Similarly the dependable energy import purchases which enable the deferral of Conawapa to 2031 are shown as Market Purchases in the Base Supply Power Resources section of the Dependable Energy Supply and Demand Table.

The Contracted Imports shown in the in the New Power Resources Section of the Dependable Energy Supply and Demand Tables are related to signed contracts which are contingent upon new resources and are therefore shown in the New Power Resources section of the table.

## SUBJECT: Imports

## REFERENCE: CAC/MH I-094

## QUESTION:

Please explain why, under New Imports, the Capacity values only extend to 2030/31 where as the Dependable Energy values extend to 2035/36. Are both not associated with the same purchase arrangements?

## RESPONSE:

Please refer to Manitoba Hydro's response to CAC/MH II-032a.

The purchases shown in the New Imports Sections of the Winter Peak Capacity and the Dependable Energy Supply and Demand Tables are not associated with the same purchase arrangements.

**SUBJECT: Imports**

**REFERENCE: CAC/MH I-095**

**QUESTION:**

If the one-year on-peak import is reflected as an increase in Market Purchases for 2024/25, why doesn't the level of Market Purchases decrease in 2025/26 (as opposed to increasing)?

**RESPONSE:**

Total Dependable Imports for each year of the development plan is based on the Generation Planning Criteria which limits the total quantity of dependable imports to that which can be imported during the off-peak period. For the K19/C25/250MW development plan a one-year on-peak import contract in 2024/25 was also included to cover a one year dependable energy deficit prior to the earliest in-service date of Conawapa and this is reflected in the Market Purchases of the Dependable Energy Supply and Demand Table located on Page 42 of Appendix 4.2.

Based on the Generation Planning Criteria total off-peak imports on 750 MW of firm import transmission (700 MW existing interconnection plus 50 MW from new interconnection) amounts to 3291 GWh. For the 2024/25 fiscal year total imports, including Contracted, Proposed and Market Purchases, amounts to 3489 GW.h which includes a 198 GW.h on-peak purchase.

For the 2025/26 fiscal year total imports amounts to 3291 GWh. If the quantity of Contracted Imports had remained the same in 2025/26 Market Purchases would have decreased. The increase in Market Purchases in the 2025/26 fiscal year is a result of the decrease in Contracted Imports in that year.

**SUBJECT: NPV**

**REFERENCE: CAC/MH 1-101**

**PREAMBLE:** The response states that the economic analysis includes the cost and benefits Manitoba Hydro experiences in proceeding with the projects.

**QUESTION:**

Please confirm that the economic analysis also includes the costs (i.e. equity contributions) and benefits (i.e. income sharing) that participating First Nations will experience.

**RESPONSE:**

Not confirmed.

As stated in Manitoba Hydro's response to CAC/MH I-101, "The economic analysis does not include any equity contributions from the participating First Nations and the income sharing. These are not project capital costs and are accounted for in the financial analyses."

## SUBJECT: NPV

## REFERENCE: CAC/MH I-102

## QUESTION:

Please provide an actual copy of Manitoba Hydro's updated Hurdle Rate Policy.

## RESPONSE:

Please see Manitoba Hydro’s response to CAC/MH II-005.

**SUBJECT: Capital Costs**

**REFERENCE: CAC/MH I-103**

**QUESTION:**

Under CGAAP are all such costs considered "expenses" or would some be capitalized?

**RESPONSE:**

The economic analysis only recognizes such costs as incremental cash flows and does not distinguish between operating and capital accounting treatment. The financial evaluation in Chapter 11 classifies equipment replacement and refurbishments costs which extend the useful life of the generating station as capital and are amortized over the life of the asset. These costs can be seen beyond the in-service date of Keeyask in the Net Capital Expenditure table for the Preferred Development Plan in Appendix 11.1 (p.6). Operating costs are recognized in the financial evaluation in the period in which they are incurred.

**SUBJECT: Rate Impacts**

**REFERENCE: CAC/MH I-103**

**QUESTION:**

Are these replacement costs all treated as O&M for purposes of the financial analyses performed in Chapter 11?

**RESPONSE:**

Please see Manitoba Hydro's response to CAC/MH II-036(a).

## SUBJECT: NPV

## REFERENCE: CAC/MH I-111

## QUESTION:

What is the impact on Table 13.3 of assuming that 75% of incremental investment is debt financed?

## RESPONSE:

As described in Manitoba Hydro's response to CAC/MH I-111, for the economic analysis of all 15 development plans analyzed in Chapter 9, a simplifying assumption was made that 80% of the capital costs will be debt financed. However, the provincial debt guarantee fee information in Table 13.3 was not derived through this economic assumption, but rather was prepared using the debt guarantee fees calculated for the eight development plans in the financial evaluation (Chapter 11). The financial evaluation assumed even-annual rate increases in order to achieve the targeted 75:25 debt:equity ratio by the end of 2031/32, and consequently the provincial debt guarantee fees tabulated in Table 13.3 were based on the projected capital structure and debt balances from year-to-year for each development plan (reference scenario). Financial projections in which the capital structure is held at 75:25 in each year are not available. Conceptually, financial projections assuming a constant 75:25 capital structure would show significantly higher rate increases in the near term of the projections, thereby generating additional cash flow such that the levels of debt financing and debt guarantee fees would be reduced during this timeframe.

## SUBJECT: NPV

## REFERENCE: CAC/MH I-111

## QUESTION:

What is the impact on Table 13.3 of assuming that 75% of incremental investment is debt financed?

## RESPONSE:

Table 13.3 was prepared recognizing that the debt:equity ratio of the corporation increases in the near term and returns to 75:25 in time. The values in Table 13.3 were based on detailed financial modeling of the entire corporation for each of the four development plans presented. The financing model for a specific development plan does not change the total debt of the corporation, and thus will not alter the debt guarantee fee that is calculatied in Table 13.3.

Estimates of the debt guarantee that were calculated using the 1% interest charge on 80% of the capital were used in determining the transfers to the province in the probabilistic evaluation for the 27 development plans Chapter 10, figure 10.8 page 19 and Chapter 9 Figure 9.3 page 25.

**SUBJECT: NPV**

**REFERENCE: CAC/MH I-111**

**QUESTION:**

Can a reasonable estimate of this impact on debt guarantee fee revenues be determined by multiplying the values in Table 13.3 by 93.75% (i.e. 75/80)?

**RESPONSE:**

Please see Manitoba Hydro's response to CAC/MH II-037b.

## SUBJECT: NPV

## REFERENCE: CAC/MH I-122

## QUESTION:

Based on the historical trends in water rental rates is it reasonable to assume that they will remain fixed over the next 35 years?

## RESPONSE:

Manitoba Hydro assumes that water rentals will be fixed over the life of the analysis because there have been no indications from the province that they will increase the rental rate. It is possible the rates could be increased or decreased. Should the water rentals increase, this would result in a decrease in the NPV of the Manitoba Hydro benefits (or the "Market Valuation Account" of Chapter 13) but would be offset by an equivalent increase in the Transfers to Government (or the "Manitoba Government Account" of Chapter 13).

**SUBJECT: NPV**

**REFERENCE: CAC/MH I-124**

**QUESTION:**

Please clarify the definition of the $22.3/MWh by indicating whether it is in real or nominal $ and whether the discount rate used to derive the levelized price is the same as that used in the reference case economic evaluation.

**RESPONSE:**

As stated in Manitoba Hydro’s response to CAC/MH I-124, the 22.3 is the mean of the 9-point representation of Figure 2.3 of Appendix 9.3. The calculation of the mean considered the probability weightings associated with Manitoba Hydro's forecasts of natural gas and carbon prices for carbon and gas across the nine scenarios identified in Figure 2.3. The 22.3 is expressed in units of $/MWh in real dollars and was determined by using the 5.05% discount rate used in the reference case economic evaluation.

## REFERENCE: Question CAC/MH I-143

## QUESTION:

Please provide materials from the credit rating agencies that review Manitoba's provincial debt and bond ratings that substantiates the claim "that the Corporation's net debt levels are excluded from this ratio".

## RESPONSE:

The ratio referenced in this information request is net tax-supported provincial debt as a percent of provincial GDP. As stated in Manitoba Hydro's response to CAC/MH I-143:

> "The ratio of net tax-supported provincial debt as a percent of provincial GDP is a measure used by organizations such as credit rating agencies in their review of provincial debt levels. However, as Manitoba Hydro's long-term debt advances are considered to be self-supporting, the Corporation's net debt levels are excluded from this ratio. Therefore, the ratio of Manitoba Hydro's net debt as a percentage of provincial GDP for each year in the study period is not an appropriate measure when reviewing Manitoba Hydro's debt levels, and organizations such as credit rating agencies do not use this measure in their analysis of Manitoba Hydro."

Credit rating reports for Manitoba Hydro and the Province of Manitoba were filed by Manitoba Hydro in response to PUB/MH I-085(a) and (b).

The credit rating agency reports for the Manitoba Hydro-Electric Board do not include ratios comparing Manitoba Hydro's debt to provincial GDP. This measure is not used by credit rating agencies in their analysis of Manitoba Hydro.

As demonstrated in the 2013 credit rating reports for the Province of Manitoba, as filed in PUB/MH I-085b, each of the credit rating agencies exclude Manitoba Hydro's debt from their ratios of provincial debt as a percentage of provincial GDP.

**Moody's**:

On page 6 of the July 23, 2013 report from Moody's on the Province of Manitoba, Moody's has a schedule which takes the total Provincial "Direct and Indirect Debt" (for example $30.531 billion for 2013F) and then subtracts Manitoba Hydro debt, Manitoba HydroBonds and Promisssory Notes, and sinking funds in order to calculate a "*Net Direct and Indirect Debt*" ($18.321 billion for 2013F). As also shown in this schedule, Moody's calculated Net Direct and Indirect Debt (which excludes Manitoba Hydro's net debt) was then used to determine the percentage of debt to GDP. In the following excerpt from page 2 of the same report, Moody's also utilizes debt levels that exclude net Manitoba Hydro debt when describing the provincial debt ratios: "As a percentage of GDP, net direct and indirect debt remained relatively stable, hovering around 30% between 2007-08 to 2012-13."

**S&P**:

On page 10 of the September 13, 2013 report from S&P on the Province of Manitoba, S&P differentiates between tax-supported debt and self-supporting debt. "At the end of fiscal 2013, tax-supported debt (adjusted for sinking funds) stood at an estimated C$18.5 billion, … Net self-supported debt, which includes debt issued for Manitoba Hydro, was C$9.6 billion." S&P's debt to GDP ratios in the report exclude Manitoba Hydro's self-supporting debt and specifically refer to the Province's tax-supporting debt. For example, on page 10 of the same report S&P states that: "In fiscal 2013, tax-supported debt increased to 33% of GDP."

**DBRS**:

On page 1 of the October 11, 2013 report from DBRS on the Province of Manitoba, DBRS includes a table of financial information that defines the provincial debt levels as being “tax-supported debt + unfunded pension liabilities.” By definition, these tax-supported debt levels and the associated debt/GDP ratios exclude Manitoba Hydro’s self-supported debt.

## REFERENCE: Question CAC/MH I-143

## QUESTION:

If no such materials can be provided, please respond to the intial information request as posed.

## RESPONSE:

Please see Manitoba Hydro's response to CAC/MH II-041a.

## REFERENCE: Question CAC/MH I-150

## QUESTION:

Please provide the 2013 Update's forecast of the various interest rates set out in Appendix 11.2 - as requested in the initial interrogatory.

## RESPONSE:

Please see the attached table.

**Projected Escalation, Interest and Exchange Rates**
**2013 Update**

| Fiscal Year Ending | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 & on |
|---|---|---|---|---|---|---|---|
| MB CPI | 1.80 | 2.00 | 2.00 | 2.00 | 2.00 | 2.00 | 2.00 |
| CDN CPI | 1.50 | 2.00 | 2.00 | 2.00 | 2.00 | 2.00 | 2.00 |
| Cdn GDP Deflator - % chg | 1.80 | 1.80 | 1.80 | 1.80 | 1.90 | 1.90 | 1.90 |
| US GDP Deflator - % chg | 1.90 | 2.10 | 1.90 | 2.00 | 2.00 | 2.00 | 1.90 |
| Hydro Project Escalation (real) - % | | | | 0.60 | | | |
| Gas Fired Generation Projects Escalation (real) - % | | | | 0.50 | | | |
| MH Short Term Cdn T-Bill Rate - % | 2.05 | 2.45 | 3.35 | 4.25 | 4.70 | 4.90 | 4.90 |
| MH Short Term Cdn BA Rate - % | 2.35 | 2.75 | 3.65 | 4.55 | 5.00 | 5.20 | 5.20 |
| MH Cdn Long Term Rate - % | 4.50 | 4.85 | 5.20 | 5.95 | 6.40 | 6.75 | 6.75 |
| MH Short Term US Rate - % | 1.65 | 2.00 | 2.55 | 4.20 | 5.05 | 5.45 | 5.55 |
| MH US Long Term Rate - % | 4.35 | 4.80 | 5.30 | 6.00 | 6.50 | 6.90 | 7.10 |
| WACC (nominal) - % | | | | 7.50 | | | |
| WACC (real) - % | | | | 5.40 | | | |
| US - Cdn Exchange Rate (Cdn $/US $) | 1.02 | 1.01 | 1.01 | 1.03 | 1.03 | 1.03 | 1.03 |
| Interest Capitalization Rate - % | 6.20 | 5.88 | 5.92 | 6.03 | 6.09 | 6.07 | 6.12 |

## REFERENCE: Question CAC/MH I-152b

## QUESTION:

Please reconcile Manitoba Hydro's choice of 6% real as the social opportunity cost of capital with the Treasury Board of Canada's recommendation that 8% is the appropriate value.

## RESPONSE:

The rationale for using a 6% discount rate in the MABCA is provided on pages 5-6 of Chapter 13. It is consistent with recent research and it is more reflective of a provincial perspective than an 8% rate. Specifically, in the weighted average opportunity cost of capital there is likely to be greater weight on inflows of capital than displacement of other investment than what Treasury Board Secretariat might assume for Canada as a whole.

## QUESTION:

Please provide copies (or internet links to copies) to both the Burgess and Zerbe study and the M. Moore et. al. study referenced in footnote #7.

## RESPONSE:

The requested articles are protected by copyright and as such Manitoba Hydro is not able to provide copies. The articles can be purchased online at the following links:

- http://www.degruyter.com/view/j/jbca.2011.2.2/jbca.2011.2.2.1065/jbca.2011.2.2.1065.xml
- http://www.degruyter.com/view/j/jbca.2013.4.issue-1/jbca-2012-0008/jbca-2012-0008.xml.

## REFERENCE: Question CAC/MH I-152c

## QUESTION:

In work Marvin Shaffer did for Manitoba Hydro regarding the Wuskwatim Project (Chapter 13, footnote #5) did he provide any view as to what the appropriate social opportunity cost of capital was? If so, please indicate what they were.

## RESPONSE:

The Wuskwatim benefit-cost analysis used a 6% to 8% discount rate. It was noted that the low end of the range is more appropriate for projects which result in greater outside borrowing (capital inflows) than displacement of other investment. Please also see Manitoba Hydro's response to CAC/MH II-044.

## REFERENCE: Question CAC/MH I-152c

## QUESTION:

Has Marvin Shaffer provided any recent (i.e., last five years) evidence/opinion as to the appropriate real social opportunity cost of capital to be used in benefit-cost analysis? If so, please provide.

## RESPONSE:

Dr. Shaffer summarizes the issues and historical research concerning the weighted average opportunity cost of capital-based discount rate on pages 124-127 of his text ***Multiple Account Benefit-Cost Analysis***, University of Toronto Press, 2010.

## SUBJECT: Project Benefits

## REFERENCE: CAC/MH I-153a

## QUESTION:

Please explain more fully why the social opportunity cost of capital is the appropriate discount rate if the Market Valuation account is looking at the project from "the point of view of Manitoba Hydro and its project partners".

## RESPONSE:

The purpose of benefit-cost analysis is to assess the benefits and costs of a project (or in this case development plan) from the point of view of society as a whole. It typically starts with the analysis of benefits and costs from the point of view of the investor or implementing agency (the incremental revenues and expenditures the project entails) and then makes a series of adjustments to capture benefits and costs to other parties (taxpayers, consumers, workers, the environment, affected communities) not fully reflected in the project incremental revenues and expenditures. In other words, adjustments are made to move from the investor perspective to the broader social point of view.

All of the benefits and costs (the project incremental revenues and expenditures and social adjustments) are estimated each year over the life of the investment or planning period. Then they are discounted to calculate the equivalent net present value of the annual cash flows. A discount rate reflecting the weighted average opportunity cost of capital is generally used.

A primary difference between the multiple account and the more traditional benefit-cost analysis is that the social adjustments are disaggregated by account to highlight trade-offs as opposed to just a bottom line, and not all of the benefits and costs are monetized, to recognize that for some consequences dollar estimates of value would not be reliable or considered appropriate.

The market valuation account in a multiple account benefit-cost analysis is in effect the starting point for any traditional benefit-cost analysis as discussed above. It captures the benefits and costs (incremental revenues and expnditures) from the point of view of the investor or implementing agency. It is called the market valuation account because it reflects the value of the project outputs and inputs at market prices.

In the case of the analysis presented in Chapter 13, the market valuation account captures the incremental revenues and expenditures for Manitoba Hydro and its project partners – what they receive from incremental export and other surplus sales, and what they pay to develop the new facilities and operate the system.

While capturing the consequences for Manitoba Hydro and its project partners, the annual benefits and costs in this market valuation account are still part of the benefit-cost analysis. They are considered along with the social adjustments – the estimated net benefits or costs to government, consumers, workers, the environment and affected communities not fully reflected in the incremental revenues and expenditures – in order to assess the net benefits from the perspective of society as a whole. Consequently, when the incremental revenues and expenditures for Manitoba Hydro and its partners are discounted to determine their equivalent present values, they are discounted at the same social opportunity cost of capital rate as the benefits and costs in all of the other accounts.

## SUBJECT: Project Benefits

## REFERENCE: CAC/MH I-153a

## QUESTION:

If the Market Valuation account looks at the project from the point of view of Manitoba Hydro and its partners, what point of view does the economic evaluation undertaken in Chapter 9 look at the project from - given it includes the same costs and benefits?

## RESPONSE:

The present values in Chapter 9 are calculated at Manitoba Hydro's discount rate. It provides an economic analysis of the consequences for Manitoba Hydro and its partners. Chapter 13 is a benefit-cost analysis of the consequences for Manitoba as a whole.

## REFERENCE: Question CAC/MH I-158

## QUESTION:

What is the basis for Manitoba Hydro's view that the various Plans will not have disproportional impacts on: i) urban vs. rural Manitobans or ii) low vs. high income Manitobans. In responding, please address the fact the various Plans will result in different patterns of future rate increases.

## RESPONSE:

How different income classes and urban versus rural residents will be affected will depend on overall cumulative rate increases, rate structure and use. What the multiple account analysis indicates is that consumers as a whole will face higher rate increases in the short to medium term and lower rate increases over the long term with the preferred plan as compared to the alternatives. The impact on different residents in the different groups in those time periods will vary depending on their use characteristics and on future rate structure decisions.

**REFERENCE: CAC/MH I-156a**

**PREAMBLE:** The NFAAT Application states: "This account (i.e. the Manitoba Economy account) assess the consequences of the different plans for the Manitoba Economy".

**QUESTION:**

Does Manitoba Hydro agree or disagree with the premise that the different plans will have different effects on the disposable income that Manitoba ratepayers will have to spend/save? If it disagrees, please explain why?

**RESPONSE:**

To the extent Manitobans' power bills are affected, there may be impacts on their ability to save or spend on other things.

**REFERENCE: CAC/MH I-156a**

**PREAMBLE:** The NFAAT Application states: "This account (i.e. the Manitoba Economy account) assess the consequences of the different plans for the Manitoba Economy"

**QUESTION:**

If Manitoba Hydro agrees, please indicate where/how the economic and social implications of these impacts are accounted for in its multiple account analyses.

**RESPONSE:**

As explained in the response to CAC/MH I-156a, benefit-cost analysis is not the same as economic impact analysis. The purpose of the economic activity account is to estimate potential employment net benefits (in economic terms, economic rents) where wages paid differ from the workers' opportunity cost. It is not clear what economic impacts may occurdue to more or less spending on power bills. Most important, Manitoba Hydro is unaware of any evidence to support that such impacts would have a significant effect on the employment net benefits (wages in excess of opportunity costs).

**REFERENCE: CAC/MH I-159**

**PREAMBLE:** Manitoba Hydro has declined to provide the requested information on the basis that the suggested approach is inappropriate.

**QUESTION:**

Does Manitoba Hydro agree that assessing the appropriateness of the analytical approaches taken by Manitoba Hydro in preparing its NFAAT application falls within the scope of the current NFAAT Review and, in particular, is part of determining whether the "preferred and alternative resource and conservation evaluations are complete, accurate, thorough, reasonable and sound"? If not, why not?

**RESPONSE:**

The response to this Information Request contemplates production of a legal argument which matter is not appropriately part of the evidence of Manitoba Hydro.

**REFERENCE: CAC/MH I-159**

**PREAMBLE:** Manitoba Hydro has declined to provide the requested information on the basis that the suggested approach is inappropriate.

**QUESTION:**

If yes, why is it appropriate for Manitoba Hydro to decline to provide information requested simply on the basis that it does not agree with the approach suggested?

**RESPONSE:**

Please see the response to CAC/MH II-050a.

**REFERENCE: CAC/MH I-159**

**PREAMBLE:** Manitoba Hydro has declined to provide the requested information on the basis that the suggested approach is inappropriate.

**QUESTION:**

Please provide a response to CAC/MH 1-159 as originally posed.

**RESPONSE:**

The use of the requested information in the multiple account benefit-cost analysis would be misleading and methodologically incorrect.

Both the market valuation account and the cumulative rate increases included in the customer account reflect the impact of the development plans on customers. The addition of the present value of both accounts would double count the development plans net benefits (or costs) in the summary table provided in Table 13.9. That would be methodologically incorrect.

**REFERENCE: CAC/MH I-159**

**PREAMBLE:** The response states: "It would be incorrect to calculate the present value of the customer rate impact and add it to the other monetized accounts because it would overlap with what is already reflected in the market valuation account"

**QUESTION:**

Please explain more fully why the calculation would overlap with what is already reflected in the market valuation account.

**RESPONSE:**

The net present value costs calculated in the market valuation account indicate the net costs that customers will have to pay for. To then calculate a net present value of the rate impact effects discussed in the customer account would double count the net cost impact, since that is what the rate impacts reflect.

**REFERENCE: CAC/MH I-159**

**PREAMBLE:** The response states: "It would be incorrect to calculate the present value of the customer rate impact and add it to the other monetized accounts because it would overlap with what is already reflected in the market valuation account"

**QUESTION:**

Please explain how this overlap differs from the overlap that exists between what is included in the Market Valuation Account and the Government Account.

**RESPONSE:**

The government account captures the adjustment needed in a multiple account benefit-cost analysis to recognize that some of what is included in the market valuation account as a cost to Manitoba Hydro (and therefore to its customers) is simply a transfer to the government. Therefore, this amount constitutes an offsetting benefit from an overall Manitoba point of view. In other words, the government account adjusts for those amounts included as Manitoba Hydro expenditures that are not resource costs from an overall Manitoba perspective.

**REFERENCE: CAC/MH I-159**

**PREAMBLE:** The response states: "It would be incorrect to calculate the present value of the customer rate impact and add it to the other monetized accounts because it would overlap with what is already reflected in the market valuation account"

**QUESTION:**

Please explain why it is inappropriate to include the overlap related to customer rates but appropriate to include the overlap associated with the items included in the Government Account.

**RESPONSE:**

Please see Manitoba Hydro's response CAC/MH II-051b.

## REFERENCE: Question CAC/MH I-159

## QUESTION:

Please explain more fully why using Manitoba Hydro's value for the social opportunity cost of capital "overstates estimates of the social time preference". In particular, why is the fact that the cost of capital is already reflected in the rate relevant, when the purpose is to look at the impact of the resulting rates on customers over different time frames.

## RESPONSE:

There are two different reasons for discounting in benefit-cost analysis: the opportunity cost of capital and the time preference rate.

The opportunity cost of capital reflects the fact that dollars received today can be invested and grow over time. The opportunity cost of capital is typically measured by the rate of return on investment before tax, because that is an estimate of the social return that can be realized with dollars received today as opposed to the future.

The time preference rate reflects the fact that people prefer benefits received sooner rather than later – it reflects the trade off people would willingly make between present and future benefits (or costs). The time preference rate is commonly measured by the after-tax rate of interest on savings because that is how much people are compensated for deferring consumption.

The social opportunity cost of capital exceeds the time preference rate because the pre-tax return on investment is significantly greater than the after tax interest rate on savings. (A classic article explaining the difference between the social opportunity cost of capital and the time preference rate is W. Baumol, “On the social rate of discount”, American Economic Review 58, no. 4 (1968), pp.788-802.)

Because of the difference between the social opportunity cost of capital and the time preference rate, a weighted average social opportunity cost is typically used in social benefit-cost analysis. This weighted average incorporates both the opportunity cost of capital and the time preference rate, as well as the cost of borrowing from outside the jurisdiction. It is higher than the time preference rate because the time preference rate is only one factor and a relatively small one in the weighted average calculation.

## REFERENCE: Question CAC/MH I-159

## QUESTION:

Please confirm that the purpose of the Rate Impact segment of the Manitoba Hydro Customer Account is to consider the relative impact on rates and what customers will pay for electricity in the short to medium vs. longer term under the various plans. If not confirmed, what is the purpose?

## RESPONSE:

The description is correct.

## REFERENCE: Question CAC/MH I-159

## QUESTION:

Please explain more fully why using Manitoba Hydro's value for the social opportunity cost of capital "overstates estimates of the social time preference". In particular, why is the fact that the cost of capital is already reflected in the rate relevant, when the purpose is to look at the impact of the resulting rates on customers over different time frames.

## RESPONSE:

The social opportunity cost of capital is a weighted average of the different sources of capital in an economy (savings, displaced investment and increased borrowing from outside the jurisdiction) and their respective costs. The social rate of time preference is the rate at which people would willingly trade-off present for future consumption opportunities (or present versus future benefits or costs). The time preference rate is commonly estimated by the after-tax interest rate on savings because that is the rate at which people are compensated for trading off present for future consumption opportunities.

## REFERENCE: Question CAC/MH I-159

## QUESTION:

In Manitoba Hydro's view, what would be the appropriate discount rate to use and why?

## RESPONSE:

Manitoba Hydro believes that for the multiple account benefit-cost analysis, consistent with standard benefit-cost practice, a social opportunity cost of capital should be used to calculate present value benefits and costs. That is what was done for all of the present value calculations in Chapter 13.

**REFERENCE: CAC/MH I-159**

**PREAMBLE:** Table 13.9 in the Application shows comparative total monetized net benefits (costs) on a PV basis for a number of the Multiple Accounts for various Plans.

**QUESTION:**

For each of the Multiple Accounts where a monetized PV has been calculated please indicate what discount rate was used and why that rate was considered appropriate.

**RESPONSE:**

As stated in the response to CAC/MH II-052c, Manitoba Hydro considers it appropriate to use a discount rate reflecting the social opportunity cost of capital for benefit-cost analysis, and that is what was used for all of the present value calculations in Chapter 13 and summarized in Table 13.9. The social opportunity cost of capital used in this analysis is 6%.

## REFERENCE: Question CAC/MH I-040a and CAC/MH I-172b

## QUESTION:

Please prepare a response to CAC/MH 1-172 b) using an own price elasticity estimate of -0.06 for all customer classes and assuming that Manitoba Hydro's current load forecast is consistent with real electricity price growth of 0% per year.

## RESPONSE:

Using a real price increase of 2% per year, and assuming a price elasticity of -0.06, the following table shows the effect the price increase would have on the electricity consumption forecast.

| Fiscal Year | 2013 Gross Firm Energy (GW.h) | Forecast With Assumed Price Effect (GW.h) | Price Effect (GW.h) |
|---|---|---|---|
| 2013/14 | 25239 | 25209 | -30 |
| 2014/15 | 25676 | 25615 | -61 |
| 2015/16 | 26013 | 25920 | -93 |
| 2016/17 | 26322 | 26197 | -125 |
| 2017/18 | 26606 | 26448 | -158 |
| 2018/19 | 27003 | 26811 | -192 |
| 2019/20 | 27398 | 27171 | -227 |
| 2020/21 | 27789 | 27527 | -263 |
| 2021/22 | 28197 | 27897 | -300 |
| 2022/23 | 28605 | 28268 | -338 |
| 2023/24 | 29013 | 28636 | -377 |
| 2024/25 | 29418 | 29002 | -416 |
| 2025/26 | 29822 | 29365 | -457 |
| 2026/27 | 30225 | 29727 | -499 |
| 2027/28 | 30625 | 30085 | -541 |
| 2028/29 | 31041 | 30456 | -585 |
| 2029/30 | 31453 | 30824 | -629 |
| 2030/31 | 31863 | 31189 | -674 |
| 2031/32 | 32265 | 31545 | -720 |
| 2032/33 | 32667 | 31900 | -767 |

## REFERENCE: CAC/MH I-175a

## QUESTION:

Please explain why it is the high upfront cost of the two hydro plants that leads to the Preferred Plan being affected by the discount rate. Doesn't the the choice of discount rate have more impact on the valuation of costs/benefits in subsequent future years as opposed to the "upfront" years?

## RESPONSE:

As stated in Manitoba Hydro's response to CAC/MH I-175a, the discount rate is one of the highest impact factors across all development plans in the economic evaluations. Discounting reduces the influence of events that occur at a later time. The development plans with a large upfront cost are affected because the benefits associated with those costs occur much later than the costs do, and as such, these benefits need to be larger to offset the costs. Development plans that have both costs and benefits distributed over the planning horizon are less sensitive to the discount rate.

## REFERENCE: CAC/MH I-176a and CAC/MH I-184a

## QUESTION:

Please provide a graphic that for each of the Plans evaluated sets out its expected NPV on one axis and its 10th percentile NPV value on the other axis.

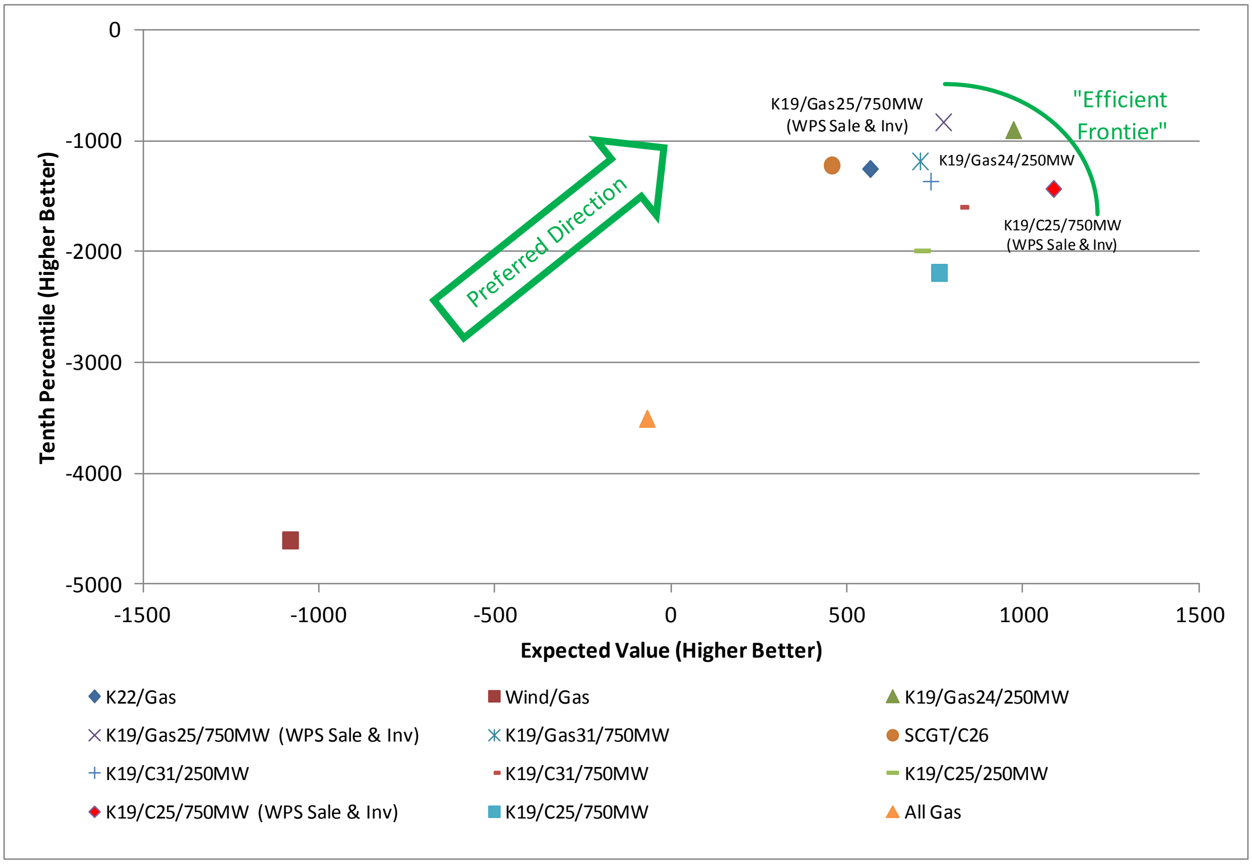
## RESPONSE:

Financial investment alternatives are sometimes displayed on an X-Y plot with the expected value of the return on one axis (a fundamental measure of return) and the standard deviation of the return on the other axis (a fundamental measure of risk). Such plots are an outgrowth of modern portfolio theory that dictates that investments should be chosen based on mean and variance. In many cases, the "efficient frontier" is also displayed – the set of non-dominated alternatives. Dominated alternatives are those where there is another choice that is better based both on mean and variance. Non-dominated alternatives are those where there is no better alternative based on both mean and variance, and where a tradeoff between risk and return is required.[1]

As discussed in CAC/MH I-184a, the standard deviation or variance is not a particularly good measure to evaluate risk-return tradeoffs for investments (such as those faced by Manitoba Hydro) with asymmetric uncertainty - more upside than downside or vice versa. A 10$^{th}$ percentile value provides a better indication of risk than standard deviation. As requested, the chart below displays the expected value on one axis and the 10$^{th}$ percentile value on the other axis for each development plan evaluated in Chapter 10 of the NFAT submission.

[1] For a more detailed explanation of modern portfolio theory, see for example David G. Luenberger, Investment Science, Oxford University Press, 2014, Chapter 6.

As the figure indicates, plans with higher expected values and higher 10th percentile values are preferred. Also, as the figure indicates, there are three non-dominated plans on the efficient frontier to the upper right: K19/Gas25/750MW (WPS Sale & Inv), K19/Gas24/250MW, K19/C25/750MW (WPS Sale & Inv).



**REFERENCE: CAC/MH I-176a**

**PREAMBLE:** The response suggests that the comparative "risks" of two Plans can be determined by looking at their relative NPVs for a specific P values.

**QUESTION:**

Assume there are two Plans and the first has a benefit of $170 guaranteed while the second has an expected benefit of $200 but the P25 and P75 values are $110 and $290 respectively. In Manitoba Hydro's view which Plan is more risky and why? Does Manitoba Hydro agree that the choice between the two Plans is not obvious and depends on the decision makers' views regarding "risk"?

**RESPONSE:**

Yes, Manitoba Hydro agrees that the choice between the two plans is not obvious and depends on the decision makers' views regarding "risk". Moreover, the decision on choosing between the plans would also consider other factors which have not been able to be integrated into the economic calculations but which would affect those calculations (e.g. opportunities or scenarios which are not quantified currently) and factors which are not able to be readily integrated into the economic calculations (e.g. energy security, reliability, socioeconomics, environmental, provincial revenues, GHG reductions, northern and aboriginal benefits, etc.).

The choice between the two alternatives clearly depends on risk aversion. A simple example based on this question may be instructive. Figure 1 shows a choice between Alternative I with a certainty of $170 and Alternative II with a 25% chance of $110, a 50% chance of $200 and a 25% chance of $290. The expected value of Alternative II is $200.

Figure 1. Decision Problem

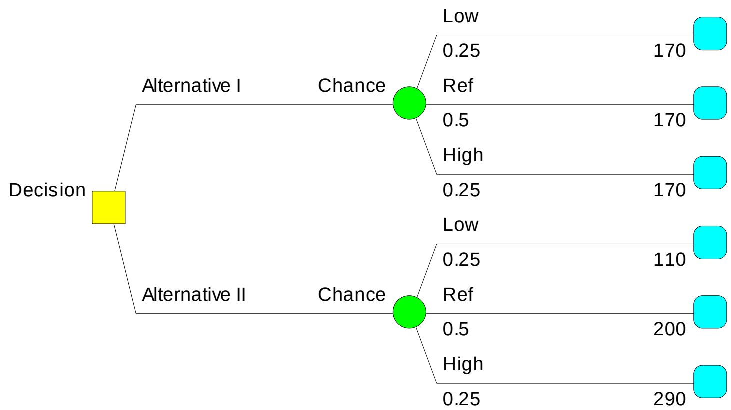
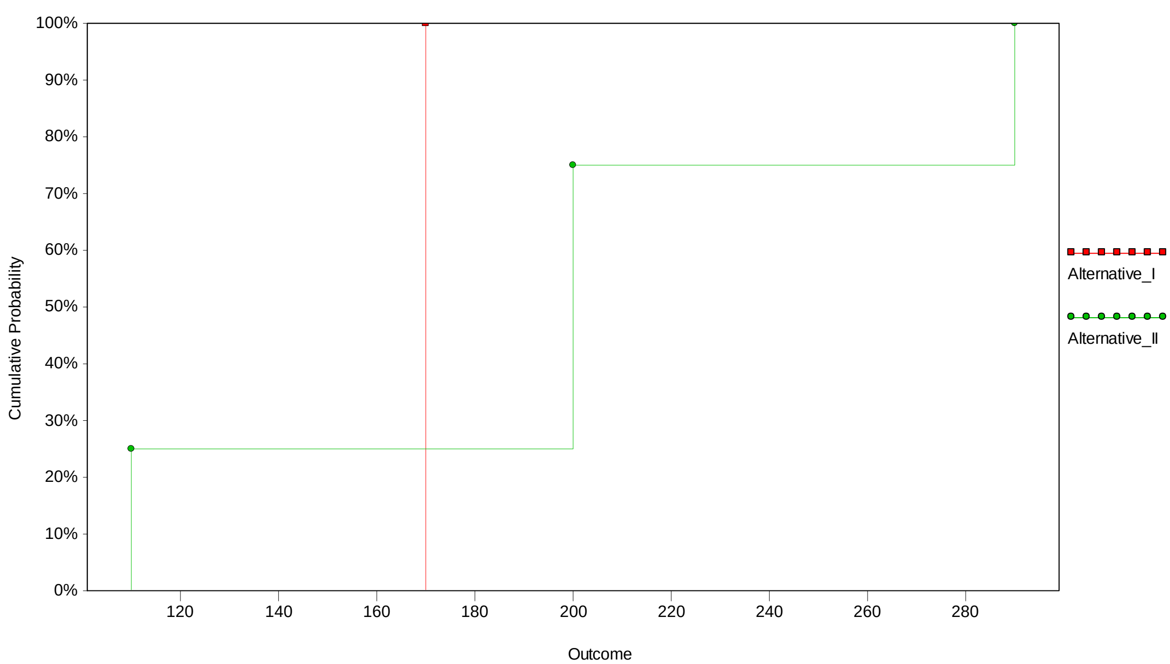



Figure 2 shows S curves for the two alternatives. As the figure indicates, the two alternatives present a choice between "lower value and lower risk" (Alternative I) and "higher value and higher risk" (Alternative II). The choice between these alternatives depends on risk attitude.

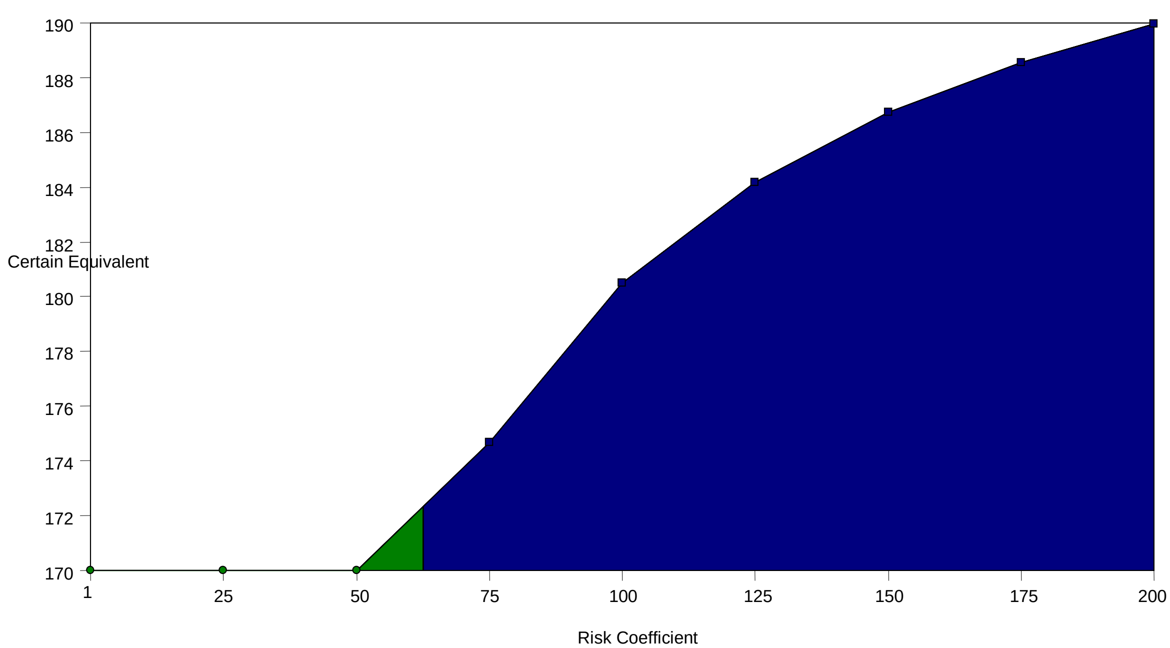
Figure 2. S Curves



Risk attitude is generally measured through what is called a utility function. One common form of utility function is exponential. An exponential utility function is characterized by a single parameter – the risk coefficient. This is also referred to as the risk aversion or risk tolerance coefficient. Using a utility function, one can convert uncertain outcomes into an equivalent fixed amount, called the "certain equivalent."

Figure 3 shows how the choice between the two alternatives varies depending on the risk coefficient. For low values of the risk coefficient (relatively risk averse), the best choice is to take the certainty of Alternative I. This is reflected in the green region of the figure. The certain equivalent is $170. For high values of the risk coefficient (relatively risk tolerant), the best choice is to choose the more uncertain Alternative II. This is reflected in the blue region of the figure. The certain equivalent if one chooses Alternative II gradually rises towards $200 with increasing risk tolerance. In this example, the switch between alternatives occurs at a risk coefficient between 50 and 75. That is, below a risk coefficient of around 62, the best choice is Alternative I; above a risk coefficient of around 62, the best choice is Alternative II.

Figure 3. Sensitivity to Risk Coefficient



There is not one correct level of risk aversion. In general, the level and importance of risk aversion reflects the characteristics of the parties affected by the decision (e.g., high wealth vs. low wealth) and the range of possible outcomes (e.g., large gains/losses vs. small gains/losses).

**REFERENCE: CAC/MH I-178**

**PREAMBLE:** The response states that: "When evaluating alternatives based on maximizing a single objectiv (such as NPV), an alternative with an S curve strictly to the right is clearely superior or dominant"

**QUESTION:**

Is it possible that even though one alternative's S curve is strictly to the right of a second alternative, it may not necessarily have the better outcome for all the possible circumstances analyzed?

**RESPONSE:**

S-curves are useful for comparing the possible outcomes of alternatives in a compact, visual way. For example, one can determine from an S-curve the probability that an alternative will have an outcome above any particular level, and which alternative has the highest probability of achieving an outcome above any particular level. This information is useful for balancing risk and return, and for identifying the best alternative. The fact that one curve is strictly to the right of another indicates that the probability of achieving an outcome above any particular level is higher with one alternative than the other, no matter what the level. This is called stochastic dominance (or sometimes first-order stochastic dominance) and generally, if the decision-maker prefers more to less, no matter what the decision-maker’s attitude towards risk is, the stochastically dominant alternative is preferable.

On the other hand, S-curves are not designed for, nor are they useful for, examining the outcome of an alternative in a particular state (or scenario) or for comparing the outcomes of alternatives in a particular scenario. The S-curve for each alternative reflects the outcome of that alternative in all scenarios, each with the appropriate probability. However, individual scenarios are not necessarily located at the same probability point on the S-curve for each alternative. Consequently, comparing S-curves at a particular probability does not represent a scenario-by-scenario comparison. For example, the fact that one curve is strictly to the right of another says very little about the comparison of outcomes in particular scenarios (as is made clear by the example below). In most approaches to economic decision-making, this "scenario-by-scenario" comparison is not highly relevant.

A simple example may be instructive.

Table 1 shows an example of a decision problem with two alternatives (I and II) in five possible scenarios (ranging from very low to very high.) It shows the name of each scenario in the first column, the probability of that scenario in the second column, and the outcome in that scenario of choosing Alternative I or Alternative II in the third and fourth columns, respectively. The expected value of Alternative I and Alternative II is also provided in the last row of the third and fourth columns, respectively. Lastly, the fifth column shows the difference between the outcomes of the two alternatives in each scenario.

Table 1 – CASE 1 Data

| | | CASE 1 | | |
|---|---|---|---|---|
| **Scenario** | **Probability** | **Alternative I** | **Alternative II** | **II-I** |
| Very Low | 10% | $ (100) | $ (75) | $ 25 |
| Low | 20% | $ (50) | $ (25) | $ 25 |
| Reference | 40% | $ - | $ 25 | $ 25 |
| High | 20% | $ 50 | $ 75 | $ 25 |
| Very High | 10% | $ 100 | $ 125 | $ 25 |
| *Expected Value* | | $ - | $ 25 | |

As the table indicates, Alternative II not only has a higher expected value by $25 but it is superior by $25 in all five scenarios. That is, no matter which scenario occurs, Alternative II comes out $25 better than Alternative I. Assuming the decision-maker prefers more money to less, it is difficult (if not impossible) to find a rationale for choosing Alternative I based on these outcomes. The decision appears obvious, and Alternative II is clearly best.

Figure 1 shows the S-curves for the two alternatives. This figure shows that Alternative II stochastically dominates Alternative I; that is, no matter what level is chosen, Alternative II always has an equal or higher probability of exceeding it. Alternative II dominates Alternative I. However, it does not show any scenario-by-scenario comparisons.

Figure 1 – CASE 1 S-Curves

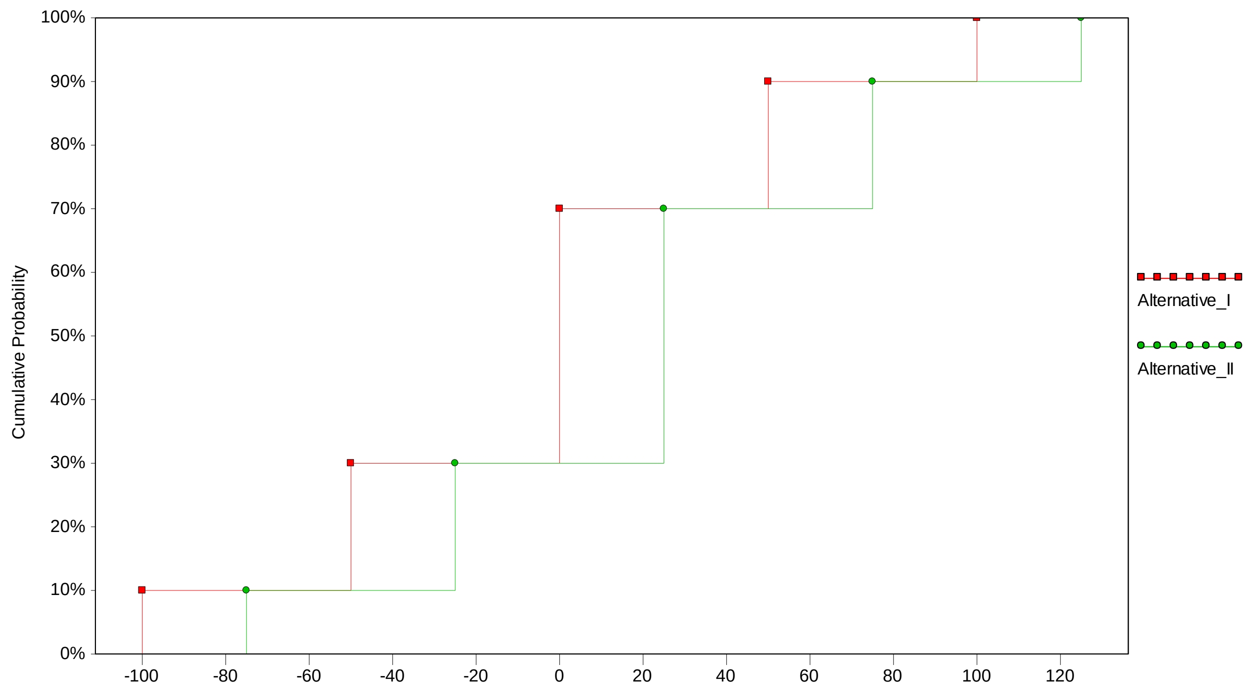



Table 2 shows a similar example with the same scenaios and probabilities. The outcomes for Alternative I given in the third column are the same as in Case 1. The outcomes for Alternative II given in the fourth column are reordered, but the expected value comparison remains the same. Alternative II has a higher expected value by $25. Because of the reordering, the difference between the outcomes of the two alternatives in each scenario, given in the fifth column, is very different than before. Depending on the scenario, Alternative II ranges from

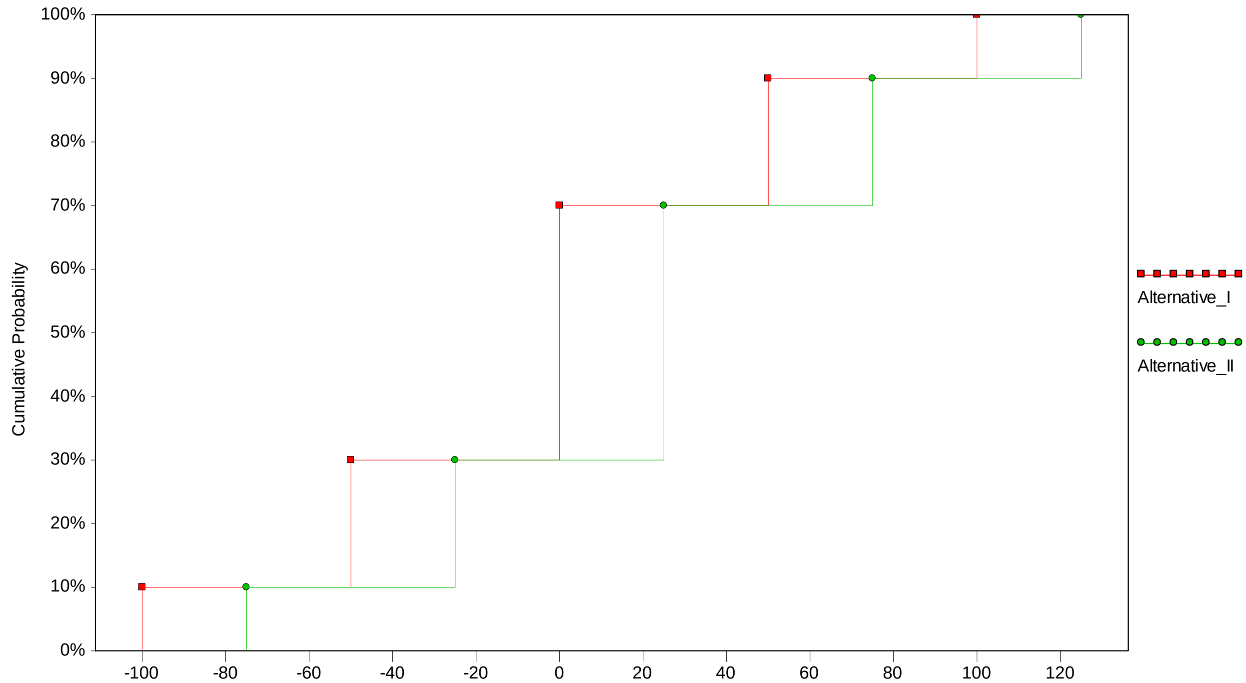
$225 better than Alternative I (in the very low scenario) to $175 worse than Alternative I (in the very high scenario).

Table 2 – CASE 2 Data

| | | CASE 2 | | |
|---|---|---|---|---|
| **Scenario** | **Probability** | **Alternative I** | **Alternative II** | **II-I** |
| Very Low | 10% | $ (100) | $ 125 | $ 225 |
| Low | 20% | $ (50) | $ 75 | $ 125 |
| Reference | 40% | $ - | $ 25 | $ 25 |
| High | 20% | $ 50 | $ (25) | $ (75) |
| Very High | 10% | $ 100 | $ (75) | $ (175) |
| *Expected Value* | | $ - | $ 25 | |

Figure 2 shows the S-curves for the two alternatives. Notice that the S-curves are exactly the same as in Case 1. As before, the S-curves reveal that, no matter what level is chosen, Alternative II always has an equal or higher probability of exceeding it. Again as before, the S-curves reveal nothing about the scenario-by-scenario comparison. Although it may not be quite so obvious, based on most views of "rational" economic decision-making, it is difficult to find a rationale for choosing Alternative I. More specifically, if the decision-maker prefers more money to less, no matter what the decision-maker's attitude towards risk is, Alternative II is best.

Figure 2 – CASE 2 S-Curves



**REFERENCE: CAC/MH I-179a**

**PREAMBLE:** The response states that "the K19/C25/750 MW plan has more surplus power than gas plans and thus would be in a better situation to accommodate higher load growth than the two gas plans"

**QUESTION:**

Please confirm that this is only true if the surplus power is dependable energy that has not been committed to firm (contracted) exports.

**RESPONSE:**

Surplus dependable energy would not be greater in the K19/C25/750 MW plan than the gas plans if all the dependable energy were committed to firm contracted exports.

However, when comparing the supply/demand tables in Appendix 4.2 of the Submission, it can be seen that the surplus firm capacity and energy would be significantly greater in the K19/C25/750 MW plan than the gas plans before new export sales are contracted in addition to the MP 250MW and WPS 300MW contracts. It is assumed that eventually those firm surpluses would be mainly eliminated through additional contracts but adding such contracts would take a number of years to achieve and in the meantime those surpluses would be available to be held back for higher than forecast Manitoba domestic load.

Furthermore, compared to the gas plans, the K19/C25/750 MW plan, even with additional firm export contracts, utilizing all dependable energy,provides a higher level of system reliability to address generation or major transmission outages or unexpectedly high load peaks, and a higher level of energy security to mitigate unexpectedly severe droughts or unexpectedly high energy consumption. This is due to a variety of reasons including the ability to give priority to Manitoba domestic load over exports contracts in unforeseen emergency conditions and the overall benefits arising from additional import capability on the new interconnection beyond that which would be included in the dependable energy determinations. Please refer to Figure 13.2 of the submission, Appendix 13.1 of the submission, Manitoba Hydro’s response to MNP/MH I-072 and Manitoba Hydro’s response to LCA/MH I-037.

## QUESTION:

For those scenarios assuming higher capital costs than in the Reference case, were the higher capital costs assumed for all new capital spending by Manitoba Hydro (including the spending common to all plans) or were the higher capital costs assumed only for the Generation and Transmission capital spending that varied across the plans?

## RESPONSE:

Under the high capital cost scenario, only the projects specific to the development plans (not the projects common to all plans) increased in cost. However, all project costs, including both the development plan specific projects and the projects common to all plans, increased due to higher escalation and interest rates under the high economic indicator scenario.

## REFERENCE: CAC/MH I-001b

## QUESTION:

Why does a plan for new interconnections and export contracts necessarily require Keeyask at an earlier date than required for Manitoba Hydro Load?

## RESPONSE:

The plan for the new interconnections and export contracts require Keeyask at an earlier date because the export counterparties are pursuing contracts with Manitaoba Hydro for supply from a new hydropower resource during that timeframe. Once Keeyask is licensed there is a high degree of certainty Manitoba Hydro will have sufficient dependable and dispatchable resources in time to meet the requirements of the export contract and provide sufficient surplus energy to justify developing the new interconnections.

Both Minnesota Power and Wisconsin Public Service want new hydro for their contracts and this interconnection rather than existing hydro or wind.

## REFERENCE: CAC/MH I-078

## QUESTION:

Please explain why the 2012/13 through 2047/48 profile for Dependable Surplus Energy is different as between the K19/Gas24/250 MW and K19/Gas25/750 MW Plans. Why aren't they the same in all years except 2024/25?

## RESPONSE:

There are differences in the amount of exportable surplus dependable energy between the K19/Gas25/750MW (WPS Sale & Inv) development plan and the K19/Gas24/250MW development plan for the following reasons:

1. The K19/Gas25/750MW (WPS Sale & Inv) development plan includes the dependable energy obligations under the proposed WPS sale agreement which decreases the amount of surplus dependable energy.

2. The K19/Gas25/750MW (WPS Sale & Inv) development plan includes a 750 MW interconnection which has a higher firm import capability than the 250 MW interconnection. The increased import capability provides additional dependable energy during the off-peak hours.

**SUBJECT: Capital Costs**

**REFERENCE: MIPUG/MH I-003c**

**QUESTION:**

For each of the four projects please show the spending by year that accumulates to the Total Sunk Costs.

**RESPONSE:**

Please see the attached table.

**Total Sunk Costs and Amortization Expense by Project**

**Economics:** **Reference**
**Market Prices:** **Reference**
**Capital Costs:** **Reference**

**($millions)**

| **Project** | **2002** | **2003** | **2004** | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** | **Total** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Conawapa GS | | | 0.2 | 8.5 | 28.1 | 32.6 | 34.0 | 33.4 | 35.2 | 29.7 | 28.2 | 56.1 | 72.1 | 17.9 | **376.1** |
| Keeyask GS | 51.8 | 25.2 | 31.2 | 33.2 | 32.2 | 36.0 | 43.0 | 54.1 | 58.5 | 55.7 | 79.8 | 197.7 | 328.7 | 159.7 | **1,186.7** |
| Keeyask GOT | 1.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | 0.1 | (1.5) | 0.7 | 0.4 | 2.1 | 1.4 | 8.5 | **13.4** |
| US Tie Line | | | | | | | | | 0.8 | 0.2 | 0.1 | 0.1 | 0.1 | 0.0 | **1.2** |
| | | | | | | | | | | | | | | | **1,577.4** |

Keeyask GOT - 2010 $1.8M of Keeaysk Transmission plus interest was transferred to BiPole III

**REFERENCE: MIPUG/MH I-009a**

**PREAMBLE:** The response states that "there is little support, analytical or empirical, for using the regret approach to make complex, future altering decisions.

**QUESTION:**

Please provide the third party references Manitoba Hydro has relied on in making this statement.

**RESPONSE:**

Please refer to Manitoba Hydro's response to MIPUG/MH II-4a.

## REFERENCE: MIPUG/MH I-013a and MIPUG/MH I-028g

## SUBJECT: NPV

## QUESTION:

For purposes of the Government Account calculations presented in Chapter 13, were the capital tax and debt guarantee fee values used consistent with those calculated in the economic or the financial analyses?

## RESPONSE:

The annual cash flow estimates of the capital tax and debt guarantee fee are consistent with the values used in the financial analysis.

## REFERENCE: MIPUG/MH I-013a and MIPUG/MH I-028g

## SUBJECT: Socio-economic

## QUESTION:

Based on the response to part (a), please comment on whether there are any inconsistencies/double counting in the presentation in Table 13.9 of the Overall Monetized Net Benefit (Cost) for the various Plans presented.

## RESPONSE:

There were no inconsistencies or double counting. Please see the response to CAC/MH II-051b.

## SUBJECT: Partnership Agreements

## REFERENCE: MIPUG/MH I-016b and MIPUG/MH I-017d

## QUESTION:

Does the non-controlling interest shown under each development plan and scenario in Appendix 11.4 include just that related to Wuskwatim and Keeyask (where applicable)? If not, what else is included?

## RESPONSE:

Please see Manitoba Hydro's responses to CAC/MH II-019(a) and (b).

**SUBJECT: Partnership Agreements**

**REFERENCE: MIPUG/MH I-017a**

**QUESTION:**

Is the 1.9% to 2.4% ownership interest range for KCN with respect to the percentage of the total project or with respect to its percentage of the total equity in the project?

**RESPONSE:**

The KCN will own between 1.9% and 2.5% of the total equity in the project.

**REFERENCE: MIPUG/MH I-038**

**SUBJECT: Load Forecast**

**QUESTION:**

Please confirm that the Medium Low and Medium High Scenario approach looked at possible changes in the load forecast due to changes in economic inputs and customer growth but not weather.

**RESPONSE:**

The Medium Low and Medium High Scenarios assumed normal weather, the same as the Base forecast.

## REFERENCE: MIPUG/MH I-038

## SUBJECT: Load Forecast

## QUESTION:

What types of uncertainties are captured in the probability based analysis adopted in the 1990's and, in particular, are they comparable to those reflected in the earlier approach?

## RESPONSE:

The probabilistic-based approach, as outlined on page 44 of the 2013 Load Forecast included as Appendix D of the submission, uses historical annual variations in weather adjusted load. It therefore incorporates all effects other than weather, namely economic, population, expansions and reductions to Top Consumers, and all other changes in energy use.

The Medium Low and Medium High scenarios represent different outlooks of future economic growth in Manitoba. When compared to the Base Forecast, the Medium Low scenario included lower population growth, lower housing formation rates, lower economic growth, lower oil and natural gas price increases, lower electric space heat saturation rates, lower business formation rates, lower business electricity usage, more shutdowns/closures of existing large customers and lower probabilities of large electrical-intensive industries locating in the province.

When compared to the Base Forecast, the Medium High scenario included higher population growth, higher housing formation rates, higher economic growth, higher oil and natural gas price increases, higher electric space heat saturation rates, higher business formation rates, higher business electricity usage, less shutdowns/closures of existing large customers and higher probabilities of large electrical-intensive industries locating in the province.

## REFERENCE: PUB/MH I-026b

## QUESTION:

Do the wind storage provisions apply regardless of whether the new intertie is for 250 MW or 750 MW?

## RESPONSE:

The wind storage provisions in the Energy Exchange Agreement with Minnesota Power are independent of the capacity of the new U.S. interconnection.

## REFERENCE: Question PUB/MH I-026b

## QUESTION:

What investment (i.e. what dollars and for what facilities) is MP making in a "new international transmission line"?

## RESPONSE:

MP is investing in 51% of the cost of the interconnection project within Minnesota. MP estimates that total construction costs for the Minnesota portion of the Project on a proxy route, including substation construction, will cost between $406 Million and $609 Million (2013 dollars) with a mid-point of $507 Million.

## REFERENCE: Question PUB/MH I-042f

## QUESTION:

Do Manitoba Hydro's firm export contracts require that the transmission system delivering the load be able to do so in the event of single contingency equipment failure?

## RESPONSE:

Yes. Manitoba Hydro’s firm export contracts require Manitoba Hydro to provide firm transmission service on the AC network to facilitate energy and capacity transfers according to the system criteria associated with firm transmission service.

However, Manitoba Hydro is not required to provide a similar level of firmness of transmission service on its HVDC system. The firm export contracts expose the buyer to the risks of the generating system which is defined to include all of Manitoba Hydro’s HVDC facilities. As a result single contingency equipment failures on the HVDC system are a reason to curtail contract deliveries to avoid curtailment of higher priority loads.

**REFERENCE: Question CAC/MH I-078b**

**QUESTION:**

Please provide the forecast operating statement for KHLP consistent with the net income projection shown in Table 2.

**RESPONSE:**

The following projected operating statement for the Keeyask Hydro Limited Partnership represents the contractual arrangements.

**Keeyask Hydro Power Limited Partnership**
**Projected Operating Statement**
**Preferred Development Plan - REF REF REF**
**(In Millions of Dollars)**

| *For the year ended March 31* | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **REVENUES** | | | | | | | | | | | | | | |
| Revenue | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 30 | 212 | 270 | 284 | 291 | 299 | 296 |
| | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 30 | 212 | 270 | 284 | 291 | 299 | 296 |
| **EXPENSES** | | | | | | | | | | | | | | |
| Operating and Administrative | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 5 | 15 | 15 | 15 | 15 | 16 | 16 |
| Finance Expense | 0 | 0 | (0) | 0 | 0 | 0 | 0 | 19 | 173 | 235 | 240 | 240 | 239 | 239 |
| Depreciation and Amortization | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 6 | 58 | 80 | 80 | 80 | 80 | 80 |
| Water Rentals and Assessments | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2 | 13 | 15 | 15 | 15 | 15 | 15 |
| | 0 | 0 | (0) | 0 | 0 | 0 | 0 | 31 | 259 | 345 | 350 | 350 | 350 | 349 |
| 1 **Net Income** | - | - | 0 | - | (0) | (0) | - | (2) | (47) | (75) | (66) | (59) | (51) | (53) |

**Keeyask Hydro Power Limited Partnership**
**Projected Operating Statement**
**Preferred Development Plan - REF REF REF**
**(In Millions of Dollars)**

| *For the year ended March 31* | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 | 2039 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **REVENUES** | | | | | | | | | | | | | |
| Revenue | 303 | 308 | 317 | 326 | 334 | 343 | 353 | 362 | 372 | 376 | 375 | 379 | 387 |
| | 303 | 308 | 317 | 326 | 334 | 343 | 353 | 362 | 372 | 376 | 375 | 379 | 387 |
| **EXPENSES** | | | | | | | | | | | | | |
| Operating and Administrative | 15 | 16 | 16 | 16 | 15 | 15 | 16 | 16 | 16 | 16 | 16 | 16 | 16 |
| Finance Expense | 235 | 233 | 231 | 229 | 216 | 207 | 205 | 201 | 198 | 195 | 191 | 188 | 184 |
| Depreciation and Amortization | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 | 80 |
| Water Rentals and Assessments | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 | 15 |
| | 345 | 344 | 342 | 339 | 326 | 317 | 316 | 312 | 309 | 305 | 302 | 299 | 296 |
| 2 **Net Income** | (42) | (36) | (25) | (14) | 8 | 26 | 37 | 50 | 63 | 71 | 73 | 80 | 92 |

**REFERENCE: PUB/MH I-088b**

**PREAMBLE:** Pages 3-72 of the response provide the debt/equity ratio for each Plan and associated scenarios.

**QUESTION:**

Can the debt/equity ratios reported for each Plan be calculated from the data provided in the schedule? If yes, please indicate how this would be done. If not, please provide a revised set of schedules with the relevant data required to calculate the debt/equity ratio and indicate how the information would be used in the calculation.

**RESPONSE:**

The debt/equity ratio can be calculated from the data provided in the response to PUB/MH II-088(b) using the following formula:

Debt /

(Retained Earnings + Contributions in Aid of Construction +

Accumulated Other Comprehensive Income + Non-Controlling Interest + Debt)

**REFERENCE: PUB/MH I-088b**

**PREAMBLE:** Pages 3-72 of the response provide the debt/equity ratio for each Plan and associated scenarios.

**QUESTION:**

Please indicate how the Debt value reported in the response can be derived from the Pro-Forma financial statements in Appendix 11.4.

**RESPONSE:**

For the purposes of the debt/equity ratio calculation, debt is the sum of the long-term (including the current portion) and short-term debt balances less sinking fund assets, short-term investments and debt attributed to the gas operations. Long-term debt on the pro forma balance sheet in Appendix 11.4 excludes the current portion which is classified in Current & Other Liabilities. Short-term debt and debt attributed to Centra Gas are also classified in Current & Other Liabilities. Sinking fund assets and short-term investments are classified in Current & Other Assets on the pro forma balance sheet.

The following schedule provides the corresponding values to calculate the debt for the Preferred Development Plan debt equity ratio under the reference scenario.

Development Plan K19 Sales C25 750 MW
Development Plan Scenario Economics:REF Rev:REF Cap:REF

ELECTRIC OPERATIONS
CALCULATION OF NET DEBT
In Millions of Dollars

| For the year ended March 31 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Long Term Debt (including current portion) | 10 097 | 11 471 | 13 114 | 14 821 | 16 700 | 18 571 | 19 744 | 21 039 | 22 406 | 23 530 | 25 080 | 26 482 | 27 685 | 28 038 | 28 239 | 28 440 | 28 581 | 28 334 | 27 636 | 27 626 | 27 399 | 25 401 | 25 202 | 24 921 | 24 523 |
| Sinking Fund Assets | (320) | (129) | (152) | (311) | (489) | (700) | (498) | (533) | (518) | (188) | (277) | (542) | (830) | (691) | (1 003) | (1 328) | (1 606) | (1 708) | (1 361) | (1 678) | (1 792) | (1 337) | (1 446) | (1 424) | (1 376) |
| Short Term Debt | 183 | 84 | 128 | 215 | 220 | 172 | 215 | 105 | 51 | 160 | 90 | 53 | - | 107 | 190 | 18 | - | - | - | - | - | - | - | - | - |
| Short Term Investments | - | - | - | - | - | - | - | - | - | - | - | - | (4) | - | - | - | (113) | (287) | (668) | (1 425) | (1 412) | (166) | (193) | (232) | (156) |
| Debt for Gas Operations | (295) | (325) | (330) | (340) | (360) | (380) | (390) | (400) | (410) | (420) | (440) | (450) | (460) | (470) | (480) | (490) | (500) | (510) | (520) | (530) | (540) | (550) | (560) | (570) | (580) |
| Net Debt for Debt/Equity Ratio | 9 665 | 11 100 | 12 760 | 14 386 | 16 072 | 17 664 | 19 071 | 20 211 | 21 530 | 23 081 | 24 453 | 25 543 | 26 392 | 26 984 | 26 947 | 26 640 | 26 362 | 25 829 | 25 088 | 23 993 | 23 655 | 23 348 | 23 003 | 22 695 | 22 412 |

Development Plan K19 Sales C25 750 MW
Development Plan Scenario Economics:REF Rev:REF Cap:REF

ELECTRIC OPERATIONS
CALCULATION OF NET DEBT
In Millions of Dollars

| For the year ended March 31 | 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 | 2046 | 2047 | 2048 | 2049 | 2050 | 2051 | 2052 | 2053 | 2054 | 2055 | 2056 | 2057 | 2058 | 2059 | 2060 | 2061 | 2062 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Long Term Debt (including current portion) | 24 375 | 24 177 | 24 279 | 24 429 | 24 378 | 24 277 | 24 625 | 24 624 | 24 622 | 25 020 | 25 019 | 24 817 | 24 490 | 24 490 | 24 489 | 24 439 | 24 238 | 22 638 | 21 837 | 21 236 | 20 829 | 20 428 | 19 702 | 19 502 | 19 102 |
| Sinking Fund Assets | (1 410) | (1 609) | (1 627) | (1 743) | (1 863) | (1 988) | (2 261) | (2 498) | (2 445) | (2 792) | (2 901) | (2 915) | (2 803) | (3 012) | (3 230) | (3 406) | (3 539) | (2 975) | (2 819) | (2 803) | (2 834) | (2 815) | (2 587) | (2 743) | (2 778) |
| Short Term Debt | - | - | - | - | - | 60 | - | 88 | 232 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| Short Term Investments | (242) | (69) | (178) | (106) | (62) | - | (66) | - | - | (105) | (340) | (508) | (650) | (830) | (947) | (1 064) | (1 028) | (366) | (144) | (69) | (153) | (243) | (257) | (381) | (447) |
| Debt for Gas Operations | (590) | (600) | (610) | (620) | (630) | (640) | (660) | (670) | (680) | (700) | (710) | (720) | (740) | (750) | (760) | (770) | (780) | (790) | (790) | (800) | (800) | (810) | (810) | (810) | (800) |
| Net Debt for Debt/Equity Ratio | 22 134 | 21 898 | 21 863 | 21 961 | 21 823 | 21 709 | 21 638 | 21 544 | 21 728 | 21 424 | 21 068 | 20 674 | 20 298 | 19 898 | 19 553 | 19 198 | 18 892 | 18 507 | 18 084 | 17 565 | 17 041 | 16 560 | 16 048 | 15 569 | 15 077 |

## REFERENCE: PUB/MH I-095b

## QUESTION:

Please provide the value for marginal cost used in the 2011-2012 Power Smart Review.

## RESPONSE:

Programs are evaluated using the same levelized marginal value that was in used in developing the program plan. Thus, the 2011-2012 Power Smart Annual Review used a levelized marginal value of 8.52 cents/kW.h (2011$), which is the marginal value used in the 2011 Power Smart Plan.

## REFERENCE: PUB/MH I-099a

## QUESTION:

Please confirm that "nominal" means the reported value is constant over the 30 years.

## RESPONSE:

The table presented in MIPUG/MH I-7a of the 2012/13 & 2013/14 Manitoba Hydro General Rate Application (GRA), refiled as PUB/MH I-099a of this proceeding, should not have been labeled "nominal dollars" as was outlined in Manitoba Hydro's response to CAC/MH II-56 of the the 2012/13 & 2013/14 GRA. The levelized marginal values are shown in the year's dollars of the associated Power Smart Plan. For example, the levelized marginal value used in the 2011 Power Smart Plan is in 2011 dollars, the levelized marginal value used in the 2010 Power Smart Plan is in 2010 dollars, etc.

**REFERENCE: PUB/MH 1-105a**

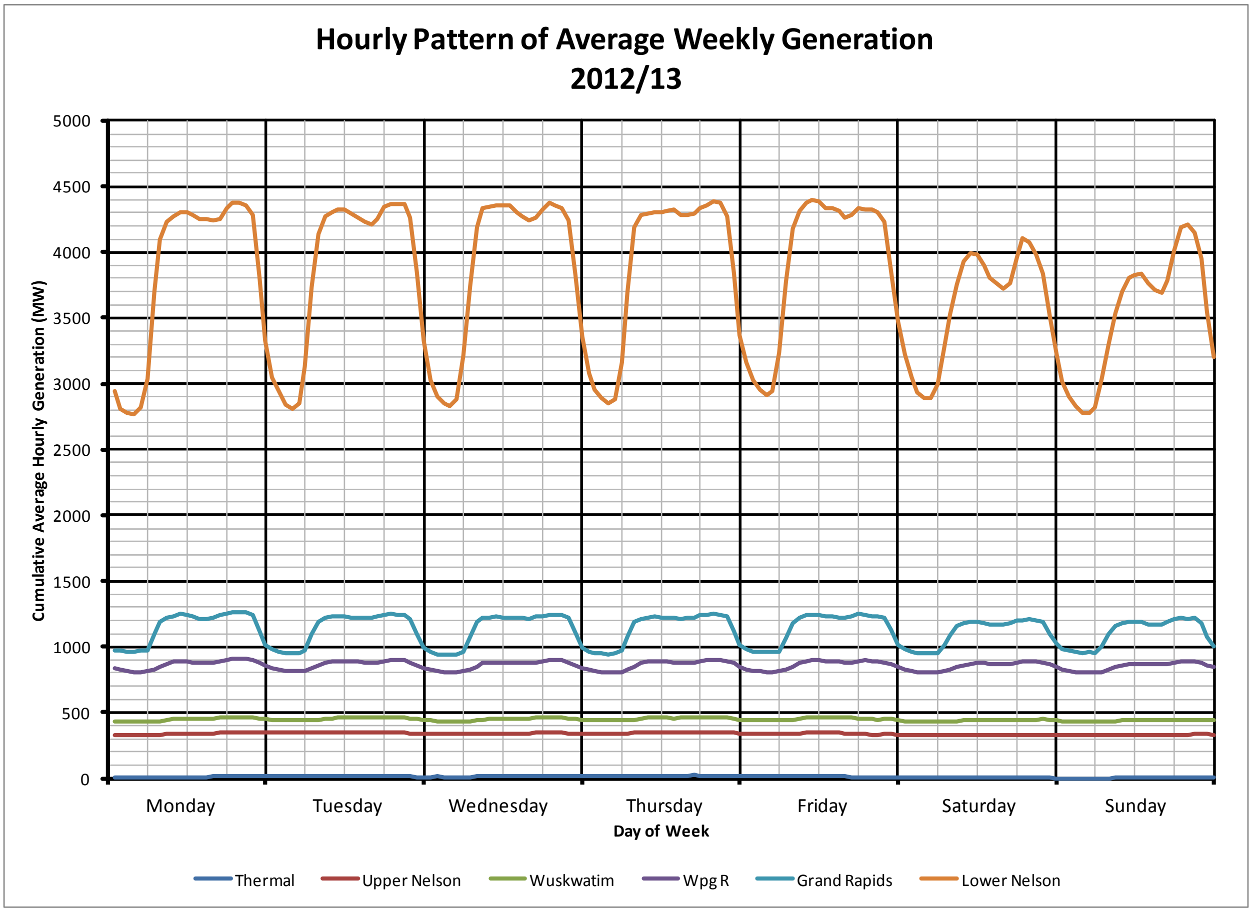
**PREAMBLE:** The last paragraph of the response compares Manitoba's Net Peak Load with the combined capacity of B I & II.

**QUESTION:**

The comparison does not account for the Manitoba Hydro generation located in the southern part of the province and which does not require the use of the Bipole lines. Please revise so as to take this additional generation into account.

**RESPONSE:**

The hydro-electric generation that does not utilize the HVDC system consists of generation at Winnipeg River generating stations, Grand Rapids generating station, Jenpeg generating station, Kelsey generating station and Wuskwatim generating station. The combined capacity of these stations is about 1650 MW, while the capacity of the stations that do utilize the HVDC system is 3550 MW (Kettle, Long Spruce and Limestone). Even if the full 1650 MW were available to meet peak loads of 4500 MW, the remaining 2850 MW must be provided by the HVDC system (or utilize thermal and imports), providing only 700 MW spare capacity (15.5%. just more than the requiste 12%). As peak load grows to 5000 MW, then 3350 MW of HVDC generation would be required, leaving only 150 MW or 3% of capacity spare; 450 MW of thermal generation would need to be available to provide the 12% capacity reserve required in planning. See the graph of average hourly generation patterns.


Hourly Pattern of Average Weekly Generation
2012/13
Cumulative Average Hourly Generation (MW)
5000
4500
4000
3500
3000
2500
2000
1500
1000
500
0
Monday
Tuesday
Wednesday
Thursday
Friday
Saturday
Sunday
Day of Week
Thermal
Upper Nelson
Wuskwatim
Wpg R
Grand Rapids
Lower Nelson

## REFERENCE: Question CAC/MH I-112b and CAC/MH I-134

## QUESTION:

This response states that the management reserves for labour and escalation were not included in the NFAT financial evaluation of Keeyask. However, the response to CAC/MH 1-134 suggests that the escalation reserve was included in the NFAT analysis. Please reconcile.

## RESPONSE:

The table in the response to CAC/MH I-134 shows the accurate breakdown of the costs included in the Conawapa capital estimate for the NFAT financial evaluation. The response to PUB/MH I-112b should have stated that the escalation reserve is included; however, the amount of escalation reserve in the NFAT financial evaluation reference scenario is lower compared to CEF12 because the reference case excludes the labour reserve.

Please also refer to Manitoba Hydro's response to PUB/MH II-447.

## REFERENCE: Question PUB/MH I-113B and CAC/MH I-135

## QUESTION:

This response states that the management reserves for labour and escalation were not included in the NFAT financial evaluation of Conawapa. However, the response to CAC/MH 1-135 suggests that the escalation reserve was included in the NFAT analysis. Please reconcile.

## RESPONSE:

The table in the response to CAC/MH I-135 shows the accurate breakdown of the costs included in the Conawapa capital estimate for the NFAT financial evaluation. The response to PUB/MH I-113(b) should have stated that the escalation reserve is included; however, the escalation reserve in the NFAT financial evaluation reference scenario is lower compared to CEF12 due to the higher escalation rate being applied to a base which excludes the labour reserve.

## REFERENCE: PUB/MH I-123b

## QUESTION:

Given the size of the MISO market, why wouldn't the maximum imports "available" under each Plan be based simply on the import capabilities provided in response to PUB/MH 1-123 a?

## RESPONSE:

The information provided in PUB/MH I-123a identifies the maximum import capability of the existing and new 250 MW and 750 MW US interconnections.

The information provided in PUB/MH I-123b identifies the highest annual imports anticipated by the SPLASH model for each of the 15 development plans. The amount of imports is based on the import capability of the interconnections and additionally will vary by plan depending on the timing and type of installed generation and firm obligations of each of the plans.

## REFERENCE: Question PUB/MH I-124

## QUESTION:

The response suggests that when Manitoba Hydro purchases power from the MISO market for import the only transmission tariffs paid are Manitoba Hydro's tariffs. Please confirm that this is the case. If so, who does the revenue from the tariff accrue to (i.e. just Manitoba Hydro or is it shared with other MISO transmission owners?)

## RESPONSE:

Confirmed. Tariff Coordination Agreements state that the transmission fees on the US side are waived provided that the energy is used to serve Manitoba network load. In Manitoba, Manitoba Hydro does not charge itself or share any revenues with MISO for network integration transmission service when energy is purchased to serve Manitoba network load.

**REFERENCE: PUB/MH I-131**

**PREAMBLE:** The response states that generally Manitoba Hydro's system offers energy that qualifies in both states.

**QUESTION:**

Please explain how Manitoba Hydro's system offers energy that generally meets Minnesota's requirement that hydro be from small (<100 MW) stations.

**RESPONSE:**

The State of Minnesota Renewable Portfolio Standard recognizes electricity generated by solar, wind, hydroelectric facilities less than 100 megawatts (MW), hydrogen and biomass as eligible for renewable status. Manitoba Hydro’s renewable energy generated from the hydroelectric facilities of Laurie River I and II, McArthur Falls, Pine Falls, Pointe du Bois and Slave Falls and the St. Leon and St. Joseph windfarms all qualify as renewable energy in Minnesota.

## Reference: Question PUB/MH I-133a

## QUESTION:

Please explain further the comment that "neither (500 kV) project was deemed eligible for cost sharing" and any implications this has for the financing of the project.

## RESPONSE:

The 500 kV alternatives were studied by MISO but neither achieved the requisite threshold to trigger project funding by MISO. Because the project does not meet the MISO funding criteria, Manitoba Hydro and Minnesota Power will have to finance the project in order for the project to move forward.

**REFERENCE: PUB/MH I-143a**

**PREAMBLE:** The response states that the balance of the interconnection facilities will be owned by Minnesota Power.

**QUESTION:**

Please indicate exactly what facilities will be owned by Minnesota Power and whether they change as between the 230 kV and 500 kV interconnection options.

**RESPONSE:**

In Manitoba, Manitoba Hydro will own all the facilities.

In Minnesota, should a 230 kV interconnection be built, Minnesota Power would own all the facilities.

In Minnesota, should a 500 kV interconnection be built, the details of the actual facilities to be owned by Minnesota Power and those whose ownership will be shared have yet to be determined. However the intent is that on an overall basis Manitoba Hydro will own 49% and Minnesota Power will own 51% of the facilities.

**REFERENCE: PUB/MH I-143a**

**PREAMBLE:** The response states that the balance of the interconnection facilities will be owned by Minnesota Power.

**QUESTION:**

Under the 500 kV option, how do those to be owned by MP facilities differ from those that it was originally anticipated that WPS would invest in?

**RESPONSE:**

Prior to WPS' funding withdrawal in the U.S. line, WPS' share was proposed to be 27% (200MW out of 750MW), and Minnesota Power's share was proposed to be 33% (250MW out of 750MW) with Manitoba Hydro owning hold the remaining 40%.

The ownership details of specific facilities associated with each ownership ratio have yet to be determined. For example within Minnesota Power's share, MP may wish to own 100% of the station costs which would require it to have a lesser ownership percentage in line costs.

## REFERENCE: Question PUB/MH I-143a and CAC/MH I-089c

## QUESTION:

The response to PUB/MH 1-143a suggests that 49% ownership gives Manitoba Hydro access to 49% of the intertie capacity for export purposes. However, the response to CAC/MH 1-089c suggests there is no link between ownership and the "right to use". Please reconcile.

## RESPONSE:

There does not need to be a match between the holders of transmission rights (“right to use”) and the owners/investors.

The “right to use” is associated with who requests and is granted transmission service rights as outlined in the transmission tariff. If requests for transmissison service exceed the available transmission capacity, the transmission provider (either Manitoba Hydro or MISO) will arrange for the construction of new facilities that satisfy requested transmission service. The parties requesting the transmission service will then be responsible for paying for the costs of the new transmission facilities.

In order to build the new facilities, the transmission provider will execute a Facilities Construction Agreement which will specify which Parties are responsible for funding, constructing and owning the new transmission line and those who will receive the new firm transmission service rights.

## REFERENCE: Question PUB/MH I-143a and PUB/MH I-143b

## QUESTION:

If Manitoba were to invest in (but not own) more than 49% of the line would the transmission rights that MISO grant it increase accordingly?

## RESPONSE:

No. These are separate issues. Please see Manitoba Hydro's response to CAC/MH II-091.

**REFERENCE: PUB/MH I-144**

**QUESTION:**

Please reconcile the $277 M cost for the Manitoba portion with the $353 M cost reported in CAC/MH 1-016b.

**RESPONSE:**

As stated in Manitoba Hydro's response to PUB/MH I-144, the cost of the Manitoba-Minnesota Transmission Project portion of the 750 MW U.S. interconnection used in analysis was $277 million (2014$ CDN). This project is described in Chapter 2 (Section 2.4) of the NFAT Business Case.

The $353 million (2014$ CDN) provided in Manitoba Hydro response to CAC/MH I-016b is the cost of the North-South Transmission Upgrade Project. This project is described in Chapter 2 (Section 2.3) of the NFAT Business Case.

## REFERENCE: PUB/MH 1-145

## QUESTION:

Does the range quoted in this response refer to the high/low cost for Manitoba Hydro's portion of the entire 500 kV interconnection - both the Manitoba and Minnesota sections? If not what does it cover?

## RESPONSE:

As stated in PUB/MH I-145, Manitoba Hydro only applied its assumptions on high and low project estimates to the portion of the capital for which Manitoba Hydro is responsible in a development plan.

The range quoted in PUB/MH I-145 refers to the high and low capital costs of the Manitoba-Minnesota Transmission Project and Manitoba Hydro’s portion of the Great Northern Transmission Line Project.

**FEFERENCE: PUB/MH I-149a**

**PREAMBLE:** The response states that the appropriate discount rate is the real return on risk free savings of the customer.

**QUESTION:**

Explain more fully why it is appropriate to use a "risk free" rate.

**RESPONSE:**

The risk-free rate is appropriate for discounting dollar amounts in the NPV analysis of consumers revenue because financial risk associated with high and low interest rates has already been incorporated into the probabilistic scenario runs. The economic analysis does not explicitly incorporate interest costs, and so the real weighted average cost of capital (RWACC) used for discounting in economic analysis incorporates financial risk. To re-introduce financial risk into the discount rate in NPV analysis of consumers revenue would be equivalent to double-counting the risk.

It is important to recognize that the discount rate in the NPV analysis of consumers revenue is used solely to weight rate impacts at different points in time.

Please also refer to MIPUB/MH II-034.

**REFERENCE: PUB/MH I-149a**

**PREAMBLE:** The response states that the appropriate discount rate is the real return on risk free savings of the customer.

**QUESTION:**

Please explain more fully why it is appropriate to use a rate that reflects return on savings and, in particular, the Short Term Canadian T-Bill rate.

**RESPONSE:**

A short-term Treasury Bill rate offered by the Government of Canada is generally accepted by economists and financial analysts to be the closest instrument to risk-free that is available in Canada. Any non-Canadian instrument would expose the individual to currency exchange risk. Longer term instruments in a normal economy typically have higher interest rates because they already incorporate higher risks associated with exposure to unforeseen economic pressures over a longer period.

**REFERENCE: PUB/MH I-149a**

**PREAMBLE:** The response states that the appropriate discount rate is the real return on risk free savings of the customer.

**QUESTION:**

Given that many customers (residential and non-residential) are carrying debt, why wouldn't a rate that reflects their savings in debt carrying costs be appropriate?

**RESPONSE:**

The debt interest rate assumed by an electric customer includes components for expected inflation, and a certain level of financial risk associated with the type and purpose of the loan. As explained in the response to CAC/MH II-095(a), financial risk should not be factored into the discount rate for NPV analysis of consumers revenue, as it has already been incorporated into the interest rates used in the probabilistic financial forecasts. As the analysis is performed in real dollars, inflation is also removed from the discount rate. Accordingly, the short-term Treasury Bill rate, adjusted for inflation, is the most appropriate rate to use.

**REFERENCE: PUB/MH I 149a**

**PREAMBLE:** NFAT Chapter 13, Footnote #7 describes the basis for the social discount rates as a weighting of three different sources of capital - savings, borrowing and borrowing from outside.

**QUESTION:**

In the Burgess and Zerbe study, what were the values they attributed to the capital from each of these sources in order to derive their 6.6%-7.3% real social opportunity cost of capital and what were the weights applied to each?

**RESPONSE:**

Burgess and Zerbe use the following estimates for the weights (sourcing of capital) and respective opportunity costs in their base case estimate. The weighted average for these values is 6.92%. The range in weighted average rates they calculate is based on different elasticities of savings, investment and outside borrowing (out of Manitoba) with respect to interest rates as shown in Table 1 of their article.

| | Displaced Investment | Increased Saving | Increased Outside Borrowing |
|---|---|---|---|
| Weight | 0.54 | 0.10 | 0.36 |
| Opportunity Cost | 8.5% | 3.5% | 5.5% |

**REFERENCE: PUB/MH I 149a**

**PREAMBLE:** NFAAT Chapter 13, Footnote #7 describes the basis for the social discount rates as a weighting of three different sources of capital - savings, borrowing and borrowing from outside.

**QUESTION:**

What would be the result if Burgess and Zerbe study was applied with a zero weight to "outside borrowing" and proportionally increase the weights for the other two sources?

**RESPONSE:**

If the weight for outside borrowing was zero, the weighted average opportunity cost would increase to approximately 7.7%.

**REFERENCE: Question PUB/MH I-149a**

**QUESTION:**

Please confirm that the NPV values in Table 11.2 - 11.7 are in 2012$. If not what is their basis?

**RESPONSE:**

The values in Tables 11.2 – 11.7 of Manitoba Hydro's response to PUB/MH I-149(a) are the cumulative general consumers revenues, which were deflated from nominal dollars to 2012$ and discounted at the 1.86% real discount rate.

## REFERENCE: Question PUB/MH I-149a

## QUESTION:

Please confirm that for Table 11.8 the inflation rate used to convert the 2013/2014 nominal dollar values to 2011/13 (constant dollar values) was the 1.8% reported in Appendix 11.2, page 1 under 2014. If this is not the case please fully explain what Manitoba Hydro fiscal year is equivalent to 2012$.

## RESPONSE:

The inflation rates listed in Appendix 11.2, labelled "MB CPI", were used to deflate all forecast years' figures from their nominal values to 2012$. Deflation is done by creating a cumulative index from the series of annual CPI figures. The index for 2013/14 would be:

Previous Year's Index x (1 + Current Year's MB CPI)

or

1.000 x (1 + 1.80%) = 1.0180

To convert 2013/14 nominal dollar consumers' revenue to 2012/2013 (2012$) you would divide by 1.0180 so $1,384 = $1,409 / 1.0180

**PREAMBLE:** The response to PUB/MH 1-149 a) suggests that it addresses CAC/MH 1-141 a&b, CAC/MH 1-142, CAC/MH 1-155b) and CAC/MH 1-163.

**REFERENCE: PUB/MH I-149 a-d**

**QUESTION:**

The response does not provide the requested information based on a 5.05% discount rate. Manitoba Hydro has indicated that it believes use of this rate to be inappropriate. As this claim is untested, please respond to the original IRs using 5.05%.

**RESPONSE:**

Please see Manitoba Hydro's response to PUB/MH II-432(b).

**REFERENCE: PUB/MH I-156a**

**PREAMBLE:** The original question requested supporting calculations related to the imputed interest rate associated with equity used in the RWACC.

**QUESTION:**

The response does not explain the basis for the imputed interest associated with equity (i.e. the 3% premium over the cost of debt). Please provide the rationale for using a 3% premium in order to determine the cost of equity - as originally requested.

**RESPONSE:**

Please see Manitoba Hydro's response to PUB/MH II-381b.

## REFERENCE: PUB/MH I-161

## QUESTION:

In what units is the 22.3 value for electricity prices expressed, over what period of time (i.e. # of years) is the levelized electricity price calculated. Is the result (22.3) in real or nominal dollars and, if real, what year's dollars?

## RESPONSE:

Please see Manitoba Hydro's responses to CAC/MH I-124 and CAC/MH II-40.

## REFERENCE: PUB/MH I-168a

## QUESTION:

Using a similar table please note the worst (in red) and best (in green) Plan for each of the 27 scenarios.

## RESPONSE:

The following table highlights in red the lowest net present value of a development plan and in green the highest net present value of a development plan for each of the 27 scenarios.

| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Energy Prices** | **Discount Rates** | **Capital Costs** | **All Gas** | **K22/Gas** | **Wind/Gas** | **K19/Gas24 /250MW** | **K19/Gas25/750MW (WPS Sale & Inv)** | **K19/Gas31/ 750MW** | **SCGT/C26** | **CCGT/26** | **Wind/C26** | **K22/C29** | **K19/C31 /250MW** | **K19/C31/ 750MW** | **K19/C25/ 250MW** | **K19/C25/750MW (WPS Sale & Inv)** | **K19/C25/ 750MW** |
| Low (30%) | Low (15%) | High (30%) | -4043 | -3792 | -7483 | -3190 | -2855 | -3418 | -3309 | -3529 | -4449 | -4064 | -3506 | -3554 | -3459 | -2841 | -3642 |
| | | Ref (50%) | -3049 | -2532 | -5189 | -1877 | -1616 | -2130 | -2401 | -2482 | -3079 | -2786 | -2166 | -2138 | -2124 | -1410 | -2177 |
| | | Low (20%) | -2247 | -1590 | -3508 | -890 | -703 | -1175 | -1655 | -1627 | -1989 | -1773 | -1099 | -1022 | -1069 | -292 | -1030 |
| | Ref (50%) | High (30%) | -463 | -1212 | -2869 | -911 | -730 | -1191 | -1297 | -1531 | -2174 | -2539 | -2161 | -2323 | -2510 | -2155 | -2816 |
| | | Ref (50%) | 208 | -278 | -1337 | 95 | 257 | -185 | -582 | -704 | -1129 | -1496 | -1050 | -1153 | -1368 | -929 | -1559 |
| | | Low (20%) | 750 | 408 | -219 | 837 | 974 | 548 | 6 | -29 | -298 | -678 | -176 | -243 | -473 | 20 | -585 |
| | High (35%) | High (30%) | 1204 | 25 | -657 | 117 | 203 | -182 | -284 | -517 | -1015 | -1659 | -1413 | -1622 | -2029 | -1810 | -2383 |
| | | Ref (50%) | 1708 | 785 | 487 | 963 | 1060 | 679 | 323 | 187 | -145 | -755 | -434 | -592 | -994 | -698 | -1243 |
| | | Low (20%) | 2114 | 1336 | 1321 | 1580 | 1674 | 1297 | 822 | 762 | 547 | -51 | 327 | 201 | -189 | 157 | -364 |
| Ref (55%) | Low (15%) | High (30%) | -5014 | -2511 | -6882 | -1796 | -2103 | -2041 | -1760 | -1703 | -2266 | -840 | -334 | 0 | 206 | 853 | 498 |
| | | Ref (50%) | -4020 | -1251 | -4588 | -482 | -865 | -753 | -852 | -656 | -897 | 438 | 1006 | 1415 | 1541 | 2284 | 1963 |
| | | Low (20%) | -3217 | -309 | -2906 | 504 | 49 | 202 | -107 | 199 | 193 | 1451 | 2073 | 2531 | 2597 | 3402 | 3110 |
| | Ref (50%) | High (30%) | -671 | -46 | -2166 | 341 | 109 | 85 | 23 | -43 | -463 | -237 | 104 | 190 | 152 | 470 | 170 |
| | | Ref (50%) | 0 | 887 | -635 | 1346 | 1097 | 1091 | 738 | 784 | 582 | 806 | 1215 | 1360 | 1295 | 1696 | 1427 |
| | | Low (20%) | 542 | 1573 | 483 | 2089 | 1813 | 1824 | 1326 | 1459 | 1414 | 1624 | 2089 | 2270 | 2189 | 2645 | 2401 |
| | High (35%) | High (30%) | 1308 | 1091 | 57 | 1258 | 1041 | 998 | 879 | 764 | 426 | 168 | 391 | 366 | 109 | 268 | 2 |
| | | Ref (50%) | 1812 | 1851 | 1201 | 2104 | 1898 | 1859 | 1487 | 1468 | 1295 | 1073 | 1370 | 1396 | 1144 | 1380 | 1143 |
| | | Low (20%) | 2218 | 2402 | 2035 | 2721 | 2512 | 2478 | 1986 | 2044 | 1987 | 1777 | 2132 | 2189 | 1949 | 2235 | 2022 |
| High (15%) | Low (15%) | High (30%) | -6435 | -1499 | -6433 | -692 | -1694 | -1006 | -355 | -23 | -173 | 2355 | 2796 | 3410 | 3819 | 4372 | 4455 |
| | | Ref (50%) | -5441 | -239 | -4140 | 621 | -456 | 282 | 552 | 1024 | 1196 | 3633 | 4135 | 4826 | 5154 | 5803 | 5921 |
| | | Low (20%) | -4638 | 703 | -2458 | 1607 | 458 | 1237 | 1298 | 1879 | 2286 | 4646 | 5203 | 5941 | 6210 | 6922 | 7068 |
| | Ref (50%) | High (30%) | -1158 | 941 | -1580 | 1398 | 713 | 1127 | 1241 | 1336 | 1172 | 2014 | 2308 | 2571 | 2746 | 2940 | 2993 |
| | | Ref (50%) | -487 | 1874 | -48 | 2403 | 1701 | 2134 | 1956 | 2163 | 2217 | 3057 | 3420 | 3741 | 3888 | 4166 | 4250 |
| | | Low (20%) | 55 | 2560 | 1070 | 3146 | 2417 | 2867 | 2543 | 2838 | 3049 | 3875 | 4293 | 4652 | 4783 | 5115 | 5225 |
| | High (35%) | High (30%) | 1210 | 2017 | 671 | 2246 | 1691 | 1993 | 1956 | 1951 | 1794 | 1935 | 2127 | 2228 | 2170 | 2203 | 2236 |
| | | Ref (50%) | 1713 | 2777 | 1816 | 3092 | 2549 | 2854 | 2563 | 2656 | 2663 | 2839 | 3106 | 3259 | 3206 | 3315 | 3377 |
| | | Low (20%) | 2120 | 3328 | 2650 | 3709 | 3163 | 3473 | 3063 | 3231 | 3355 | 3543 | 3867 | 4051 | 4010 | 4170 | 4256 |

1

## REFERENCE: PUB/MH I-187

## QUESTION:

Please confirm that the discussion of losses provided in the response is with respect to losses on Manitoba Hydro's system and does not cover any additional losses related to exports that may/will be incurred on U.S. transmission facilities. In calculating revenues are export volumes further adjusted to account for such losses?

## RESPONSE:

It is confirmed that the losses described in PUB/MH I-187 reflect the estimated losses over the Manitoba Hydro system.

The point of delivery for export transactions is at the Manitoba – U.S. border, referred to as the Manitoba Hydro Electric Board node. Losses within the MISO market are accounted for in the congestion component of the locational marginal price, rather than using a volume adjustment for losses. As noted in the response to CAC/MH I-075a, "Manitoba Hydro applies a basis differential to the forecast MINN HUB prices to account for losses and congestion between MINN HUB and MHEB".

## REFERENCE: Question PUB/MH I-190

## QUESTION:

Please explain why this type of technical assessment is considered Commercially Sensitive Information.

## RESPONSE:

The technical assessment referenced in PUB/MH 1-190 contains Critical Energy Infrastructure information. Any specific engineering, vulnerability, or detailed design information about proposed or existing critical infrastructure (physical or virtual) in the referenced report that:

1. Relates details about the production, generation, transmission, or distribution of energy;
2. Could be useful to a person planning an attack on critical infrastructure; or
3. Gives strategic information beyond the location of the critical infrastructure;

is required to be kept confidential.

**REFERENCE: PUB/MH I-225a**

**PREAMBLE:** Chapter 13, Tables 13.2 and 13.3 set out values for Coal Taxes and Potential Carbon Charges paid to the Manitoba Government.

**QUESTION:**

If not included in the economic evaluation but included in the Market Evaluation (per Table 13.2), please reconcile this with the statement on page 5 (Chapter 13) that the market evaluation relied on the same annual revenue and expenditure cash flows as the economic evaluation.

**RESPONSE:**

The economic evaluation does include provincial coal taxes and carbon charges on gas generation.

**REFERENCE: PUB/MH I-225a**

**PREAMBLE:** Chapter 13, Tables 13.2 and 13.3 set out values for Coal Taxes and Potential Carbon Charges paid to the Manitoba Government.

**QUESTION:**

Are Coal Taxes and Potential Carbon Charges paid to the Manitoba Government included in the Financial Evaluation (Chapter 11)?

**RESPONSE:**

Coal taxes and potential carbon charges are included in the financial evaluation in Chapter 11.

**REFERENCE: PUB/MH I-231**

**PREAMBLE:** In Chapter 13 (page 32), only capital tax and water rentals were included as net benefits to the Manitoba Government.

**QUESTION:**

Why was the debt guarantee fee included in the transfers to the Province for purposes of the Conclusions (Chapter 14, Figure 14.1 and page 53) but not in the Manitoba Government part of the Multiple Account analysis?

**RESPONSE:**

The provincial debt guarantee fees are payments made by Manitoba Hydro to the Province of Manitoba. The Province utilizes these transfers as it sees fit for the benefit of Manitobans and therefore the provincial debt guarantee fees were treated as representing a benefit which should be considered in Chapter 14, along with water rentals and capital taxes. In Chapter 14 the benefits to Manitoba Hydro and the transfers to government are shown separately; they are not combined in an overall evaluation so as to recognize the difference in the characteristics of these benefits.

The provincial debt guarantee fees were not included as part of the net benefits in Chapter 13 because it was assumed that the fees are paid in exchange for the guarantee that the Province provides.

**REFERENCE: PUB/MH 1-231**

**PREAMBLE:** In Chapter 13 (page 32), only capital tax and water rentals were included as net benefits to the Manitoba Government.

**QUESTION:**

Please reconcile the total benefits of Pathways 4 and 5 ($3,098 M and $3,697 M respectively) shown on pages 53-54 with the values shown in Figure 14.1 of Chapter 14. In doing so, please provide a schedule that sets out the derivation of these two values.

**RESPONSE:**

The question above refers to the comparison of the NPV of 3 development plans: All Gas, K19/C31/750MW (Pathway 4) and K19/C25/750MW (Pathway 5). The table below includes the information included in the Figure 14.1 only for these plans.

**Development Plan NPV's – Including Potential Cash Transfers to the Province @ 5.05% Real Discount Rate**

**(Millions 2014 Dollars)**

| Development Plan / Pathway | Benefits to Manitoba Hydro | Water Rental & Capital Tax | Provincial Guarantee Fee | Total Development Plan NPV |
|---|---|---|---|---|
| All Gas – Pathway 1 | 131 | 209 | | **340** |
| K19/C31/750MW – Pathway 4 | 1,360 | 960 | 1,270 | **3,438** |
| K19/C25/750MW -– Pathway 5 | 1,696 | 1,094 | 1,247 | **4,037** |

The NPV of the K19/C31/750MW development plan minus the NPV of the Alll Gas plan is $3,098 million ($3438- $340).

The NPV of the K19/C25/750MW development plan minus the NPV of the Alll Gas plan is $3,697 million ($4,037 - $340).

**REFERENCE:** Question PUB/MH I-244 and PUB/MH I-177a

**QUESTION:**

The response states that over the period additional cash transfers are fully recovered from incremental export revenue. Please confirm that the "period" referred to is the 68 year study period.

**RESPONSE:**

The total study life or period used for the economic analysis is 78 years (See Section 1.2 in Appendix 9.3 – Econoimc Evaluation Documentation). The financial evaluation encompasses a 50-year study period (See Section 11.2 in Chapter 11 – Financial Evaluation of Development Plans).

## REFERENCE: Question PUB/MH I-245

## QUESTION:

Please confirm that 6% was the discount rate used to establish the 2014 present value under each Plan.

## RESPONSE:

Confirmed.

## REFERENCE: Question PUB/MH I-245

## QUESTION:

Why is this considered to be the appropriate discount rate for applying to employment benefits?

## RESPONSE:

The same discount rate was used for all of the present value calculations in Chapter 13, in accordance with standard benefit-cost practice.

## REFERENCE: Question PUB/MH I-245 and PUB/MH I-149a

## QUESTION:

Why shouldn't the same discount rate be used for employment benefits (accruing to Manitobans in the form of wages) Manitoba Hydro also be applied to General Consumer Revenues (being paid by Manitobans) as opposed to Manitoba's approach which is to use 6% and 1.83% respectively?

## RESPONSE:

The present value of the employment benefits was calculated using the same weighted average opportunity cost of capital-based rate (6%) that was used to discount all monetized benefits and costs in the Multiple Account Benefit-Cost Analysis.

The discount rate used in the financial analysis (and not in any part of the MABCA in Chapter 13) serves a different purpose. Its purpose is to weight the rate impacts at different points in time in order to calculate a levelized value indicator of the impact over the planning period. The discount rate in the financial analysis is based on what economists call time preference – the rate that reflects the trade-off that people would willingly make between benefits or costs now and in the future.

## REFERENCE: Question PUB/MH I-246

## QUESTION:

Please confirm that 6% was the discount rate used to establish the 2014 present value under each plan.

## RESPONSE:

Confirmed.

## REFERENCE: Question PUB/MH I-246

## QUESTION:

Why is this considered to be the appropriate discount rate for applying to GHG external costs?

## RESPONSE:

Please see Manitoba Hydro's response to CAC/MH II-114b.

## REFERENCE: PUB/MH I-247c

## QUESTION:

Why were bill savings from DSM not included in the Multiple Account analysis in Chapter 13?

## RESPONSE:

The four development plans considered in the Multiple Account Evaluation have included the same level of DSM. Therefore, the impact of DSM in the analysis is indifferent when comparing among these plans.

## REFERENCE: PUB/MH I-247c

## QUESTION:

Under what circumstances would it be appropriate to include such savings in the Multiple Account Analysis.

## RESPONSE:

It would be necessary to consider the consequences of DSM if the DSM expenditures and or savings differed among the plans.

## REFERENCE: Question PUB/MH I-247c

## QUESTION:

Please provide a general description of how this would be done (i.e. how would the annual savings for each Plan be determined and how would they be discounted?).

## RESPONSE:

The consequences of differing levels of DSM on the overall net benefits of the different development plans would be captured by taking into account:

1) the reduction in Manitoba Hydro expenditures for new supply and /or increase in export sales revenues and/or other changes in generation production cost because of the estimated reduction in domestic electricity requirements;
2) Manitoba Hydro's expenditures in support of the DSM initiatives; and
3) customer expenditures required to achieve the reduction in requirements.

The net of those effects (present valued at the 6% social opportunity cost-based discount rate) would indicate how Manitoba Hydro and its customers as a whole would be affected (whether and to what extent there would be customer savings).

The distributional effect on different groups of customers, in particular DSM program participants versus non-participants would be based on comparing rates associated with different levels of DSM, all being applied to the same development plan.

Development plans can be compared to each other at different levels of DSM but each set of comparisons would assume the same level of DSM.

## REFERENCE: PUB/MH 1-259

## QUESTION:

Over what period of time (i.e. # of years) is the 6.69 cents/kWh levelized value of avoided cost calculated? Also, please confirm that the value is expressed in real 2012$.

## RESPONSE:

The marginal value of 6.69 cents/kWh was levelized over 30 years, between 2012-13 and 2021-22.

The value of 6.69 cents/kWh is expressed in 2012 constant (real) dollars.

## REFERENCE: Question PUB/MH I-1-288a, PUB/MH I-289b and PUB/MH I-289c

## QUESTION:

Please confirm that all of the contracts set out in Appendix 9.3, Table 1.9 have terms specifically tying Manitoba Hydro to the construction of new hydraulic generation with annual dependable energy in excess of the contract amounts.

## RESPONSE:

Confirmed. Although the contracts listed in Table 1.9 of Appendix 9.3 do not require Manitoba Hydro to build anything, they have been predicated on that occurring and anticipate the delivery of energy and equivalent amounts of environmental attributes from new large hydro facilities.

The addition of Keeyask and Conawapa will add new dependable hydraulic energy in excess of the amounts needed by the contracts.

**SUBJECT: Caribou**

**REFERENCE: CAC/MH I-170**

**PREAMBLE:** "Fuel pricing is one of the most important considerations driving electrical resource decisions and regional market prices for electricity. Recent reductions in cost due to developments in shale gas extraction have increased the attractiveness of natural gas as a supply source, particularly in relation to coal."

**QUESTION:**

Please provide any information Manitoba Hydro has on the price elasticity of electricity demand.

**RESPONSE:**

Please see Manitoba Hydro's response to PUB/MH I-256.

**REFERENCE: Appendix D 2013 Electric Load Forecast; Page No.:59**

**PREAMBLE:** To determine low income rate impact CAC MB requires the following information.

## QUESTION:

For 2009, based on the Residential Survey, please provide the average annual electricity bill for residential customers by location (Winnipeg/Non-Winnipeg), home ownership status (Own/Rent) and dwelling type (single detached/other).

## RESPONSE:

Based on the 2009 Residential Energy Use Survey, the following table shows the 2009 average annual electricity bill, taxes included, by location, ownership and dwelling type.

| LOCATION | OWNERSHIP | DWELLING TYPE | 2009 AVERAGE ANNUAL ELECTRICITY BILL |
|---|---|---|---|
| **Winnipeg** | Own | Single Detached | $889 |
| | | Multi-Attached | $737 |
| | | Apartment Suite | $570 |
| | Rent | Single Detached | $689 |
| | | Multi-Attached | $801 |
| | | Apartment Suite | $402 |
| **Outside Winnipeg** | Own | Single Detached | $1,670 |
| | | Multi-Attached | $1,147 |
| | | Apartment Suite | $1,032 |
| | Rent | Single Detached | $1,641 |
| | | Multi-Attached | $852 |
| | | Apartment Suite | $577 |

**REFERENCE: Appendix D 2013 Electric Load Forecast; Page No.:59, CAC/MH I-190**

**PREAMBLE:** To determine low income rate impact CAC MB requires the following information.

**QUESTION:**

For the period of January 2000 to June 2008, please provide the total number of residential customers by month in each of the following four categories:

(1) <200 amp service <175 KWh;

(2) <200 Amp & >175 kWh;

(3) >200 Amp & <175 kWh;

(4) >200 Amp & >175 kWh.

**RESPONSE:**

The following presents the number of residential customers broken out by the above noted categories:

| Residential Basic Customer Counts by Monthly Consumption | | | | | |
|---|---|---|---|---|---|
| | RES BASIC <200 AMP | | RES BASIC >200 AMP | | |
| Month | Less than 175 kW.h | Greater than 175 kW.h | Less than 175 kW.h | Greater than 175 kW.h | Total Customers |
| 2000 JAN | 6,756 | 272,187 | 8 | 1,387 | 280,338 |
| 2000 FEB | 8,106 | 269,381 | 11 | 1,377 | 278,875 |
| 2000 MAR | 9,728 | 271,293 | 13 | 1,398 | 282,432 |
| 2000 APR | 9,900 | 267,450 | 13 | 1,360 | 278,723 |
| 2000 MAY | 12,630 | 267,442 | 10 | 1,381 | 281,463 |
| 2000 JUN | 18,124 | 262,648 | 22 | 1,367 | 282,161 |
| 2000 JUL | 16,078 | 265,341 | 28 | 1,368 | 282,815 |
| 2000 AUG | 16,494 | 264,114 | 22 | 1,391 | 282,021 |
| 2000 SEP | 14,799 | 268,634 | 12 | 1,426 | 284,871 |
| 2000 OCT | 11,582 | 270,511 | 7 | 1,427 | 283,527 |
| 2000 NOV | 10,013 | 274,582 | 13 | 1,442 | 286,050 |
| 2000 DEC | 7,644 | 272,752 | 11 | 1,441 | 281,848 |
| 2001 JAN | 7,242 | 275,658 | 13 | 1,451 | 284,364 |
| 2001 FEB | 8,277 | 270,930 | 11 | 1,439 | 280,657 |
| 2001 MAR | 10,045 | 272,672 | 12 | 1,440 | 284,169 |
| 2001 APR | 10,860 | 269,140 | 6 | 1,407 | 281,413 |
| 2001 MAY | 13,682 | 269,212 | 16 | 1,407 | 284,317 |
| 2001 JUN | 17,214 | 265,656 | 18 | 1,402 | 284,290 |
| 2001 JUL | 16,128 | 268,104 | 31 | 1,417 | 285,680 |
| 2001 AUG | 16,604 | 265,579 | 26 | 1,432 | 283,641 |
| 2001 SEP | 16,627 | 269,122 | 15 | 1,462 | 287,226 |
| 2001 OCT | 12,106 | 273,599 | 14 | 1,488 | 287,207 |
| 2001 NOV | 10,555 | 277,359 | 15 | 1,502 | 289,431 |
| 2001 DEC | 9,042 | 280,013 | 13 | 1,532 | 290,600 |
| 2002 JAN | 7,446 | 278,424 | 13 | 1,514 | 287,397 |
| 2002 FEB | 8,432 | 275,286 | 8 | 1,496 | 285,222 |
| 2002 MAR | 9,312 | 276,659 | 9 | 1,506 | 287,486 |
| 2002 APR | 9,987 | 274,239 | 19 | 1,476 | 285,721 |
| 2002 MAY | 12,019 | 273,272 | 11 | 1,457 | 286,759 |
| 2002 JUN | 17,778 | 268,972 | 23 | 1,472 | 288,245 |
| 2002 JUL | 15,503 | 271,775 | 20 | 1,485 | 288,783 |
| 2002 AUG | 16,815 | 271,113 | 20 | 1,500 | 289,448 |
| 2002 SEP | 16,240 | 274,408 | 20 | 1,541 | 292,209 |
| 2002 OCT | 10,478 | 279,723 | 10 | 1,531 | 291,742 |
| 2002 NOV | 9,249 | 282,567 | 7 | 1,571 | 293,394 |
| 2002 DEC | 8,559 | 280,872 | 12 | 1,562 | 291,005 |

| | | | | | |
|---|---|---|---|---|---|
| 2003 JAN | 7,222 | 283,455 | 9 | 1,574 | 292,260 |
| 2003 FEB | 7,582 | 281,221 | 14 | 1,564 | 290,381 |
| 2003 MAR | 8,625 | 282,178 | 12 | 1,583 | 292,398 |
| 2003 APR | 10,418 | 278,371 | 14 | 1,570 | 290,373 |
| 2003 MAY | 12,435 | 277,800 | 11 | 1,570 | 291,816 |
| 2003 JUN | 18,448 | 272,600 | 34 | 1,548 | 292,630 |
| 2003 JUL | 16,482 | 276,604 | 16 | 1,579 | 294,681 |
| 2003 AUG | 16,391 | 273,119 | 28 | 1,577 | 291,115 |
| 2003 SEP | 16,933 | 277,816 | 21 | 1,625 | 296,395 |
| 2003 OCT | 12,193 | 282,214 | 18 | 1,642 | 296,067 |
| 2003 NOV | 9,076 | 286,527 | 13 | 1,672 | 297,288 |
| 2003 DEC | 8,557 | 285,401 | 11 | 1,668 | 295,637 |
| 2004 JAN | 6,789 | 288,128 | 13 | 1,691 | 296,621 |
| 2004 FEB | 7,657 | 284,963 | 14 | 1,659 | 294,293 |
| 2004 MAR | 9,170 | 286,491 | 13 | 1,648 | 297,322 |
| 2004 APR | 9,957 | 283,381 | 13 | 1,635 | 294,986 |
| 2004 MAY | 12,576 | 283,541 | 21 | 1,662 | 297,800 |
| 2004 JUN | 37,116 | 331,242 | 27 | 1,625 | 370,010 |
| 2004 JUL | 31,430 | 341,220 | 28 | 1,648 | 374,326 |
| 2004 AUG | 32,942 | 338,343 | 25 | 1,662 | 372,972 |
| 2004 SEP | 30,694 | 344,926 | 14 | 1,728 | 377,362 |
| 2004 OCT | 25,728 | 348,657 | 16 | 1,785 | 376,186 |
| 2004 NOV | 22,845 | 353,433 | 16 | 1,931 | 378,225 |
| 2004 DEC | 18,600 | 353,717 | 22 | 2,009 | 374,348 |
| 2005 JAN | 16,632 | 355,653 | 20 | 2,049 | 374,354 |
| 2005 FEB | 20,297 | 349,311 | 22 | 2,019 | 371,649 |
| 2005 MAR | 22,691 | 349,359 | 20 | 2,021 | 374,091 |
| 2005 APR | 23,496 | 347,699 | 14 | 1,998 | 373,207 |
| 2005 MAY | 27,141 | 346,109 | 28 | 1,966 | 375,244 |
| 2005 JUN | 33,951 | 360,137 | 27 | 1,975 | 396,090 |
| 2005 JUL | 30,408 | 366,346 | 40 | 2,018 | 398,812 |
| 2005 AUG | 34,303 | 366,125 | 43 | 2,037 | 402,508 |
| 2005 SEP | 33,841 | 370,676 | 40 | 2,054 | 406,611 |
| 2005 OCT | 29,286 | 375,886 | 18 | 2,089 | 407,279 |
| 2005 NOV | 24,102 | 384,189 | 19 | 2,132 | 410,442 |
| 2005 DEC | 22,540 | 388,240 | 16 | 2,114 | 412,910 |
| 2006 JAN | 18,529 | 391,695 | 22 | 2,175 | 412,421 |
| 2006 FEB | 23,011 | 386,168 | 18 | 2,165 | 411,362 |
| 2006 MAR | 25,044 | 384,950 | 33 | 2,162 | 412,189 |
| 2006 APR | 47,602 | 376,147 | 98 | 2,122 | 425,969 |
| 2006 MAY | 54,881 | 369,147 | 148 | 2,083 | 426,259 |
| 2006 JUN | 52,906 | 371,254 | 153 | 2,082 | 426,395 |
| 2006 JUL | 50,360 | 374,154 | 130 | 2,120 | 426,764 |
| 2006 AUG | 54,801 | 370,076 | 143 | 2,119 | 427,139 |
| 2006 SEP | 51,972 | 373,255 | 99 | 2,181 | 427,507 |
| 2006 OCT | 47,083 | 378,560 | 111 | 2,197 | 427,951 |

| | | | | | |
|---|---|---|---|---|---|
| 2006 NOV | 41,782 | 384,519 | 115 | 2,225 | 428,641 |
| 2006 DEC | 41,219 | 385,439 | 88 | 2,273 | 429,019 |
| 2007 JAN | 36,436 | 390,535 | 71 | 2,301 | 429,343 |
| 2007 FEB | 39,520 | 387,777 | 81 | 2,300 | 429,678 |
| 2007 MAR | 44,617 | 382,941 | 91 | 2,298 | 429,947 |
| 2007 APR | 48,754 | 379,025 | 126 | 2,273 | 430,178 |
| 2007 MAY | 57,694 | 370,282 | 142 | 2,267 | 430,385 |
| 2007 JUN | 54,705 | 373,566 | 143 | 2,271 | 430,685 |
| 2007 JUL | 52,775 | 375,813 | 149 | 2,270 | 431,007 |
| 2007 AUG | 53,637 | 375,290 | 149 | 2,282 | 431,358 |
| 2007 SEP | 54,893 | 374,414 | 129 | 2,311 | 431,747 |
| 2007 OCT | 53,793 | 376,022 | 141 | 2,327 | 432,283 |
| 2007 NOV | 42,666 | 387,647 | 119 | 2,367 | 432,799 |
| 2007 DEC | 40,858 | 389,906 | 92 | 2,416 | 433,272 |
| 2008 JAN | 33,952 | 397,242 | 76 | 2,456 | 433,726 |
| 2008 FEB | 37,214 | 394,244 | 78 | 2,460 | 433,996 |
| 2008 MAR | 36,872 | 394,921 | 86 | 2,459 | 434,338 |
| 2008 APR | 43,694 | 388,471 | 105 | 2,447 | 434,717 |
| 2008 MAY | 48,449 | 384,054 | 131 | 2,426 | 435,060 |
| 2008 JUN | 56,523 | 376,495 | 186 | 2,385 | 435,589 |

Please note the following data considerations:

January 2000 – June 2004: The data displays the number of bills split by Rate group and classified based on monthly usage from the billing system prior to conversion to the current billing system. Due to constraints of the previous system, customers on bi-monthly billing would be categorized based upon the energy for the entire billing period. This data does not include previous Winnipeg Hydro customers as this is prior to the acquisition.

June 2004 – March 2006: The data displays the number of bills split by Rate group and classified based on monthly usage from the billing system prior to conversion to the current billing system. Due to constraints of the previous system, customers on bi-monthly billing would be categorized based upon the energy for the entire billing period. This data includes previous Winnipeg Hydro customers.

April 2006 – June 2008: The data displays the number of customers in each month split by Rate Group and classified based on the monthly usage. For customers on bi-monthly billing, for the months the customer did not have a bill, the customer would be included in the count for the under 175 kW.h category.

**REFERENCE: Appendix D 2013 Electric Load Forecast; Page No.:59 ; Question CAC/MH I-190**

**PREAMBLE:** To determine low income rate impact CAC MB requires the following information.

## QUESTION:

For the period of July 2008 to March 2011, please provide the total number of residential customers in each of the following four categories:

(1) <200 Amp&<900 kWh;

(2) <200 Amp&>900 kWh;

(3) >200 Amp&<900 kWh;

(4) >200 Amp&>900 kWh,

by month.

## RESPONSE:

The following presents the number of residential customers broken out by the above noted categories:

## Residential Basic Customer Counts by monthly consumption

| Month | RES <200AMP | | RES >200AMP | | Total Bills |
|---|---|---|---|---|---|
| | < 900 kW.h | > 900 kW.h | < 900 kW.h | > 900 kW.h | |
| 2008 JUL | 269,698 | 163,689 | 566 | 2,021 | 435,974 |
| 2008 AUG | 255,897 | 177,920 | 517 | 2,084 | 436,418 |
| 2008 SEP | 258,877 | 175,415 | 437 | 2,200 | 436,929 |
| 2008 OCT | 267,987 | 166,993 | 375 | 2,289 | 437,644 |
| 2008 NOV | 227,926 | 207,597 | 242 | 2,461 | 438,226 |
| 2008 DEC | 198,671 | 237,314 | 172 | 2,562 | 438,719 |
| 2009 JAN | 151,122 | 285,126 | 136 | 2,619 | 439,003 |
| 2009 FEB | 185,833 | 250,757 | 157 | 2,604 | 439,351 |
| 2009 MAR | 198,401 | 238,344 | 188 | 2,587 | 439,520 |
| 2009 APR | 207,242 | 229,757 | 211 | 2,571 | 439,781 |
| 2009 MAY | 250,245 | 186,979 | 299 | 2,495 | 440,018 |
| 2009 JUN | 252,590 | 184,869 | 375 | 2,434 | 440,268 |
| 2009 JUL | 268,063 | 169,744 | 577 | 2,240 | 440,624 |
| 2009 AUG | 276,878 | 161,213 | 608 | 2,239 | 440,938 |
| 2009 SEP | 273,590 | 164,951 | 551 | 2,313 | 441,405 |
| 2009 OCT | 237,726 | 201,387 | 302 | 2,580 | 441,995 |
| 2009 NOV | 234,800 | 204,737 | 272 | 2,650 | 442,459 |
| 2009 DEC | 205,980 | 233,908 | 206 | 2,770 | 442,864 |
| 2010 JAN | 159,097 | 281,040 | 161 | 2,833 | 443,131 |
| 2010 FEB | 192,642 | 247,763 | 171 | 2,840 | 443,416 |
| 2010 MAR | 208,981 | 231,630 | 239 | 2,772 | 443,622 |
| 2010 APR | 229,303 | 211,523 | 287 | 2,738 | 443,851 |
| 2010 MAY | 259,483 | 181,483 | 384 | 2,655 | 444,005 |
| 2010 JUN | 279,506 | 161,768 | 598 | 2,455 | 444,327 |
| 2010 JUL | 238,161 | 203,411 | 575 | 2,509 | 444,656 |
| 2010 AUG | 230,889 | 211,065 | 616 | 2,489 | 445,059 |
| 2010 SEP | 272,045 | 170,353 | 647 | 2,491 | 445,536 |
| 2010 OCT | 277,128 | 165,724 | 472 | 2,701 | 446,025 |
| 2010 NOV | 232,173 | 211,286 | 307 | 2,928 | 446,694 |
| 2010 DEC | 196,372 | 247,555 | 226 | 3,032 | 447,185 |
| 2011 JAN | 160,619 | 283,626 | 201 | 3,067 | 447,513 |
| 2011 FEB | 191,977 | 252,432 | 206 | 3,064 | 447,679 |
| 2011 MAR | 190,092 | 254,681 | 242 | 3,038 | 448,053 |

**REFERENCE: Chapter 11: Financial Evaluation of Development Plans; Section: 11.2; Page No.:7; CAC/MH 1-139**

**PREAMBLE:** To determine low income rate impact CAC MB requires the following information.

## QUESTION:

Please provide a schedule that sets out Manitoba Hydro's approved Residential rates for 1999 and 2000 and the effective dates for rates during those two calendar years.

## RESPONSE:

Residential electricity rates in effect for 1999 and 2000 are shown below. These rates were in effect as of April 1, 1997 and remained in effect until November 1, 2001, when Uniform Rate Legislation was introduced. Prior to uniform rates (which allowed for all grid-connected customers in Manitoba to pay the same class rates), rates varied by rate zone. A description of these zones is provided below.

| **Residential** | **Zone 1** | **Zone 2** | **Zone 3** |
|---|---|---|---|
| Monthly Basic Charge: | | | |
| <200 Amp | $6.25 | $7.63 | $13.65 |
| >200 Amp | $12.50 | $13.88 | $19.90 |
| Energy Charge: | | | |
| First 175 kWh | $0.0578 | $0.0653 | $0.0733 |
| Balance of kWh | $0.0516 | $0.0516 | $0.0516 |

**Zone 1:** Winnipeg (legal boundary)

**Zone 2:** Medium Density – 100 metered services or more with a line density of at least 15 customers per kilometer of distribution line outside of Zone 1.

**Zone 3:** Low Density – less than 100 metered services, outside of all other rate zones.

**SUBJECT: Export Markets; Load Forecast**

**REFERENCE: CAC/MH I-201**

**PREAMBLE:** In the response to CAC/MH I-201, it is indicated that CO2 price sensitivities were performed by MISO, Northern States Power, and Minnesota Power.

**QUESTION:**

How does the load growth for those sensitivities compare to the base or BAU cases for the three entities?

**RESPONSE:**

MISO's 2012 Transmission Expansion Plan's "Combined Policy" scenario references a Demand growth rate of 0.5%/year and Energy growth rate of 1.9%/year. However these results should be prefaced that the "Combined Policy" scenario includes a number of variant assumptions relative to the BAU case (i.e. more than just a carbon price). Below is a short synopsis of the scenario provided in the MISO MTEP 2012 report (page 116):

> *The Combined Policy future scenario was developed to capture the effects of multiple future policy scenarios into one future. This scenario includes a federal RPS, smart grid and electric vehicles. The federal RPS assumes all states are required to meet a 20 percent federal RPS mandate by 2025. This future includes 23 GW of coal retirements, with the smallest and least efficient coal units retired. Smart grid is modeled by reducing the demand growth rate, assuming that a higher penetration of smart grid will lower the overall growth of demand. Electric vehicles are modeled by increasing the energy growth rate. They are assumed to increase off-peak energy usage and increase the overall energy growth rate.*

Manitoba Hydro cannot confirm what load growth assumptions were used by Minnesota Power and Northern State Power in their CO2 sensitivity analysis.

**SUBJECT: Natural Gas**

**REFERENCE: CAC/MH I-205**

**PREAMBLE:** In the response to CAC/MH I-205, it is indicated that volatility results will vary by natural gas hub.

**QUESTION:**

Are you aware of any North American hubs where natural gas prices still exhibit high volatility over the past 5 years?

**RESPONSE:**

The response to CAC/MH I-205 noted that volatility in the post-2006 period will vary depending on the specific North American natural gas hub chosen. This statement refers to the 2007 U.S. Energy Information Administration natural gas price volatility study which noted different historical levels of price volatility at the benchmark Henry, Chicago, and New York City Hubs. Manitoba Hydro does not have a comprehensive database of historical price volatility data for all North American natural gas hubs. However, natural gas prices at the Transco NY and Algonquin Citygate trading points in the Northeast U.S. in particular have recently experienced high price volatility as a result of local pipeline constraints and high pipeline transportation load factors due to residential and commercial fuel switching away from refined petroleum products to natural gas and increased use of gas-fired power generation (see U.S. EIA Short-Term Energy Outlook Supplement, January 2013:

http://www.eia.gov/forecasts/steo/special/pdf/2013_sp_01.pdf ).

A recent study prepared by ICF International for the ISO New England concludes that while improved supply access over the long-term will lower volatility, New England will continue to see higher price volatility than the Henry Hub for the foreseeable future (see Section 3.2 of Gas-

Fired Power Generation in Eastern New York and its Impact on New England's Gas Supplies, November 2013:

http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2013/nov202013/icf_upstream_gen_impacts_white_paper_11-18-2013.pdf

**SUBJECT: Export Markets; Price Forecasts**

**REFERENCE: CAC/MH I-209**

**PREAMBLE:** In the response to CAC/MH I-209, it is indicated that the impact of new hydro generation on regional export prices would be minimal with no transmission constraints. The Independent Market Monitor for MISO currently defines three Narrow Constrained Areas (Minnesota, Wisconsin-Upper Michigan, and North Wisconsin-Upper Michigan) [Pg.61 of the 2012 State of the Market Report].

**QUESTION:**

How would the new Manitoba Hydro generation impact export prices if the constraints identified by the Independent Market Monitor are not alleviated?

**RESPONSE:**

Manitoba Hydro notes that the discussion on page 61 of the 2012 State of the Market Report address market power rather than physical transmission congestion. As stated on page 61, "NCAs are chronically constrained areas that raise more severe potential local market power concerns (i.e., tighter market power mitigation measures are employed)". In other words, the comment specifically relates to the monitoring for the potential exertion of market power during period of high demand/ prices, not identifying regions that are necessarily experiencing negative economic impacts due to physical congestion of the transmission system.

MISO's June 2013 Northern Area Study stated:

> *"Economic benefits for MISO from new potential Manitoba Hydro to MISO tie-lines could be realized with minimal incremental transmission investment. The Northern Area Study identified Hankinson – Wahpeton 230 kV & Big Stone – Morris 115 kV upgrade as a cost-effective option to mitigate the remaining out-year congestion from wind on the*

*Dakotas – Minnesota border (B/C ratio 3.46 – 14.74 depending on scenario assumption).”*

The Northern Area study concluded that only “*minimal incremental transmission investment”* to the existing transmission system will be required to take advantage of Manitoba Hydro’s new export power capacity, and the two identified upgrades showed significant overall economic benefits. Manitoba Hydro has not conducted a specific price impact analysis with and without the Hankinson – Wahpeton 230 kV & Big Stone – Morris 115 kV upgrades. However, given the overall benefits to the market and the minimal incremental transmission investment required for the upgrades, it is a reasonable assumption that both of these upgrades will be undertaken as part of MISO’s formal transmission planning process. Therefore, Manitoba Hydro anticipates that new hydro generation, combined with proposed transmission interconnection upgrades as per the Preferred Development Plan, and with anticipated transmission updates within MISO, would not increase existing congestion, in the region and in turn, would not negatively impact export market prices due to congestion.

**SUBJECT: Wind**

**REFERENCE: CAC/MH I-213**

**PREAMBLE:** In the response to CAC/MH I-213, four benefits to Manitoba Hydro's domestic customers are identified. The first of these, labeled "a", refers to favorable recognition in US markets of the complementary nature of hydropower and wind and the benefits to US consumers.

**QUESTION:**

Please explain how this benefits Manitoba Hydro's domestic customers.

**RESPONSE:**

The response to CAC/MH 1-213 stated in part:

"Additional benefits to Manitoba Hydro's domestic customers which were beyond the scope of the MHWSS but which also result from new hydropower in Manitoba and a new 500 kV transmission line include:

a) Favorable recognition in U.S. markets of the complementary nature of new renewable hydropower in Manitoba and planned wind power development in MISO. As a result new hydro is not seen as a competitor to US wind but rather as necessary to enable additional wind development. This recognition may result in US decision makers and regulators being even more supportive of imports from Manitoba Hydro. The substantial Load Cost Savings identified by the MHWSS and the displacement of carbon-based energy in MISO with carbon-free energy from Manitoba are two significant benefits for U.S. consumers which are important to U.S. decision makers and regulators."

Support of U.S. decision makers and regulators for imports from Manitoba Hydro is an important part of the Preferred Development Plan and for Manitoba Hydro's exports in general. The Minnesota Public Utilities Comission (MPUC) has already approved the 250 MW sale to

Minnesota Power, and is also reviewing the Minnesota section of the new interconnection (the Great Nothern Transmission line). Without these approvals, the benefits that the preferred development plan brings to Manitoba Hydro's domestic customers would not be obtained.

**SUBJECT: Export Markets**

**REFERENCE: CAC/MH I214a**

**PREAMBLE:** In the response to CAC/MH I-214a, it is indicated that Minnesota imports 15 TWh of their states' electricity needs.

**QUESTION:**

Please confirm that even if all of those imports were generated from coal, the amount of electricity derived from coal in Minnesota is 63%.

**RESPONSE:**

Mathematically, if the 15 TWh of imports to Minnesota referenced in CAC/MH I-214a were all assumed to be coal generation, the portion of coal generation in the Minnesota electricity energy mix would be around 63%.

As previously noted in the response to CAC/MH 1-214a, "MISO does not dispatch generation within a state to meet only the loads within a state. Rather MISO dispatches the entire regional generation fleet to meet the aggregate load of the region, subject to transmission limits, and without regard to state boundaries."

**SUBJECT: Wind**

**REFERENCE: CAC/MH I-215a**

**PREAMBLE:** In the response to CAC/MH I-215a, a map indicting the amount of wind capacity by state is used to indicate that most of the wind in MISO is located in Iowa and Illinois. Figure 1-1 of MISO's 2013 Wind Capacity Report indicates that there is only 625 MW of wind in MISO's Zone 4 and 5 combined (covering Illinois and Missouri) and only 287 MW is in Zone 6 (Indiana and Kentucky), while 79% of wind capacity is in Zones 1 (the Dakotas, much of Minnesota, and western Wisconsin) and 3 (Iowa and southern Minnesota).

**QUESTION:**

Please confirm that much of the wind generation indicated on the NREL map in the southern MISO states is not actually located in MISO.

**RESPONSE:**

Manitoba Hydro cannot confirm that much of the wind generation indicated on the NREL map in the southern MISO states is not actually located in MISO. Manitoba Hydro does not have access to the NREL mapping information as it relates to MISO membership. However, it is Manitoba Hydro’s understanding that much of the wind generation in Iowa is owned or contracted to MidAmerican Energy, who is Iowa’s largest energy company and a MISO member.

**SUBJECT: Carbon/GHG Emissions**

**REFERENCE: CAC/MH I-217**

**PREAMBLE:** In the response to CAC/MH I-217, it is indicated that the assumption of 0.75 tonnes Co2/MWh is appropriate for the current GHG displacements associated with Manitoba Hydro's net exports.

**QUESTION:**

Will the impending retirement of coal-fired capacity due to current EPA rules and the assumed CO2 restrictions affect the future GHG emission displacements, therefore affecting the appropriateness of the 0.75 tonnes/MWh assumption?

**RESPONSE:**

Manitoba Hydro considers the 0.75 kg CO2e/kW.h assumption to be a reasonable estimate of the GHG benefits associated with hydropower exports into the northwest MISO region. In the longer term, the displacement of natural gas generation still offers substantial global GHG emission reductions.

Given that there have been several IRs seeking to better understand how greenhouse gas (GHG) emission displacements could change over time, Manitoba Hydro retained the Brattle Group to model annual marginal GHG emission displacements associated with increasing electricity exports from Manitoba over a 20-year period (2015-2034). The resulting study *$CO_2$ Emissions Displacement Resulting from Increased Manitoba Hydro Exports to MISO* is attached. The Brattle model considers a number of key export region effects including coal retirements, climate change policy (CO2 pricing), fossil fuel prices and renewable additions. Sensitivity to higher and zero CO2 prices were also examined. Some of the study’s key conclusions are as follows:

- Manitoba Hydro's exports displace an average of 0.85 kg CO2/kW.h (850 tonnes CO2/GW.h) over the next 20 years within the export region modeled. This value is dominated by marginal coal displacements.
- Beyond 2030 the GHG emission displacement begins drop-off towards that of combined cycle natural gas generation at approximately 0.4 kg CO2/kW.h (400 tonnes CO2/GW.h).
- Under a high carbon price scenario, this drop-off may occur a few years earlier.
- The results show little sensitivity to the level of hydro exports or the daily timing (peak/off-peak) of those exports.

To date, in the absence of any specific evidence on which to forecast changes, Manitoba Hydro has assumed a constant GHG displacement factor of 0.75 kg CO2e/kW.h (750 tonnes CO2e/GW.h) throughout the planning horizon. This Brattle report suggests that this assumption understates the emissions displacement over the next 20 years while it may overestimate the emission displacements thereafter.

The Brattle Group

# $CO_2$ Emission Displacement Resulting from Increased Manitoba Hydro Exports to MISO

Prepared for
**Manitoba Hydro**


***The Brattle Group***
Dean Murphy
Onur Aydin
Kent Diep


**February 2014**



**www.brattle.com**

# Table of Contents

# Context and Assignment

**Manitoba Hydro is the primary electricity provider to Manitoba**

- Hydro-dominated generation, serving Manitoba and export markets
- Significant exporter to the U.S. upper Midwest (MISO)

**Manitoba Hydro engaged The Brattle Group to assess the $CO_2$ emissions that would be displaced in the MISO system by additional Manitoba Hydro exports to the U.S.**

- Simulate system as is, and with additional exports into MISO (uniform increment of energy across all hours)
- Analysis provides $CO_2$ displaced (annual total and per unit increment of energy) for the regional power market
  - Sensitivity to alternative market scenarios, and to peak vs off-peak timing of incremental exports, was also tested

**This report is developed specifically for use in Manitoba Hydro's Needs For and Alternatives To (NFAT) regulatory hearing, and should not be used for other purposes**

# Approach

**To understand the emission displacement effects of additional exports, we simulated the regional power system over a 20-year period (2015-2034) using ReCap, a model developed by The Brattle Group**

- ♦ We modeled MRO-West and neighboring sub-regions, covering MISO and parts of PJM and SPP, to account for the interconnected nature of the U.S. power system
- ♦ A brief description of ReCap is contained in the Appendix

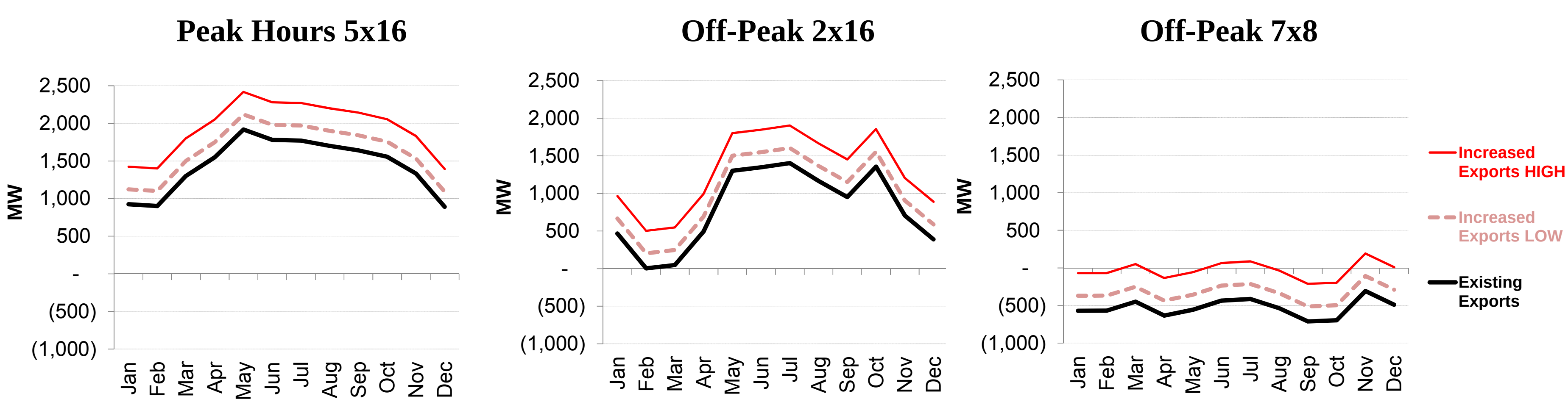
**Three <u>cases</u> were considered – Existing Exports, vs Increased Exports at two different levels – and resulting $CO_2$ emissions were compared**

- ♦ This was done in the context of the Base Case market scenario that was used in Brattle's 2013 Long-Term Price Forecast
- ♦ Two other scenarios (also from the 2013 Forecast) were analyzed to determine sensitivity to alternative market conditions
  - These alternate scenarios were not designed to test the potential range of emission displacement, but they do represent very different system conditions
  - Summaries of the Base Case and alternate market scenarios are in the Appendix

# Increased Hydro Exports Assumptions

- **Existing Exports: c**onsistent with current system in average water conditions; 670 MW average, with seasonal and hourly shape; 1000 MW capacity exports
- **Increased Exports – Low:** energy exports into MISO increased by 200 MW in each hour (+1,750 GWh/year), plus additional 300 MW capacity exports
- **Increased Exports – High:** energy exports into MISO increased by 500 MW in each hour (+4,380 GWh/year), plus additional 750 MW capacity exports

- Incremental energy has no seasonal or hourly shape – same in every hour
  - Though sensitivity analysis was performed to understand the potential effect of shaping exports



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# Typical Emission Factors and System Effects

**Typical emission factors:***

- Coal: 10 MMBtu/MWh * 0.10 tons $CO_2$/MMBtu = 1 ton $CO_2$/MWh
- Gas CC: 7.5 MMBtu/MWh * 0.05 tons $CO_2$/MMBtu = 0.4 tons $CO_2$/MWh
- Gas CT: 12 MMBtu/MWh * 0.05 tons $CO_2$/MMBtu = 0.6 tons $CO_2$/MWh

**Although this is a useful guide, system effects mean that no simple rule will yield actual emission displacement**

- There is diversity in emission rates even at units of the same type
  - Different heat rates (among coal and gas plants); $CO_2$ content of fuel (coal types)
- Also, the regional power market is a blend of coal and gas units
  - Emissions displaced are sometimes those of the short-run marginal unit – though what unit is on the margin changes with time and system conditions
  - Other times, the emissions of a coal unit retired earlier, or a new gas unit whose addition is delayed, may be displaced
- Simulation modeling can illuminate these system effects

*** Gas CC = natural gas-fired combined cycle unit; Gas CT = natural gas-fired combustion turbine unit**
**Throughout this report, emission quantities and rates are expressed in terms of metric tons**

# Results:

# Effect of Increased Exports on $CO_2$ Emissions

# MH's Export Region is Heavily Dominated by Coal

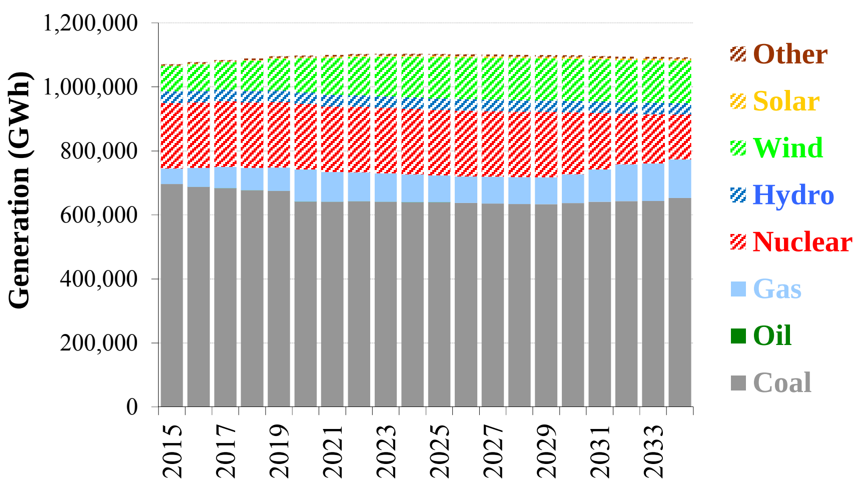
**The study region is dominated by coal, which provides the majority of energy**

- **Remainder is mostly nuclear and renewable (wind), with some gas**
  - **MISO is a subset of the study region, and is more reliant on coal, with a smaller share of nuclear and slightly less wind**
  - **MRO-West, the study sub-region that corresponds to the Minn Hub export market, is somewhat less coal dependent due to its greater wind energy share**

**Because of coal's dominance, displaced generation will often be coal-fired, with a high emission rate**

- **But market simulation – characterizing the interplay of long-term investment and short-term operations – is necessary to understand how hydro exports displace other generation, and the ultimate effect on emissions**

**Projected Energy Generation by Type in Study Region (Base Case)**



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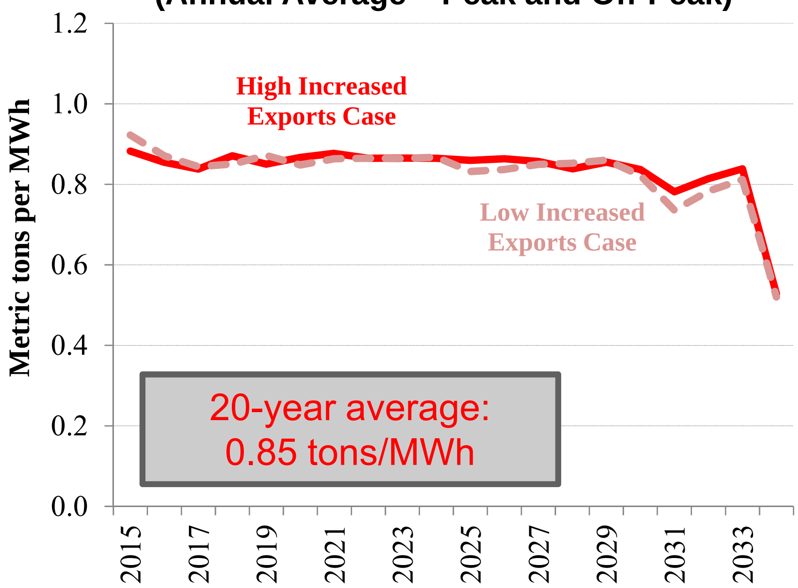
# Emission Displacement Results – Base Case

- **Exports reduce MISO $CO_2$ emissions by ~0.85 tons per incremental MWh**
- **Displacement rate is very similar for Low and High Increased Exports cases**
  - Manitoba Hydro exports at any level are small relative to MISO, so have similar per-unit effect
- **Displacement is stable to ~2030**
  - Displacing mostly coal; some gas
  - No carbon-free generation (wind, solar, nuclear) is displaced
  - Minor year-to-year variability in displacement is not significant (see discussion at page 19)
  - Only modest sensitivity to timing of exports (e.g., peak vs off-peak – see discussion at page 20)

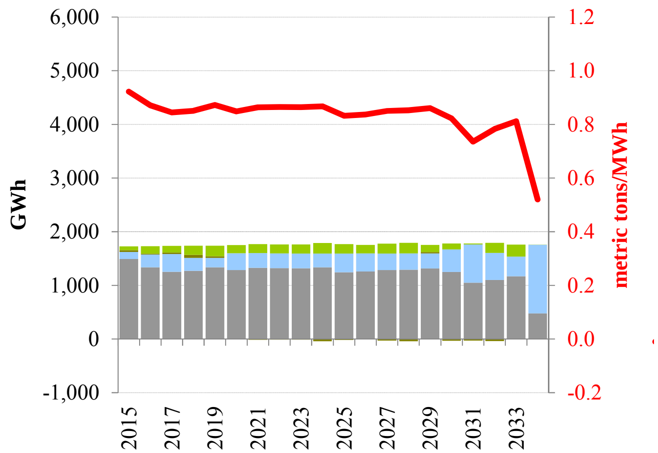
**System $CO_2$ Emissions – Displacement Rate (Annual Average – Peak and Off-Peak)**



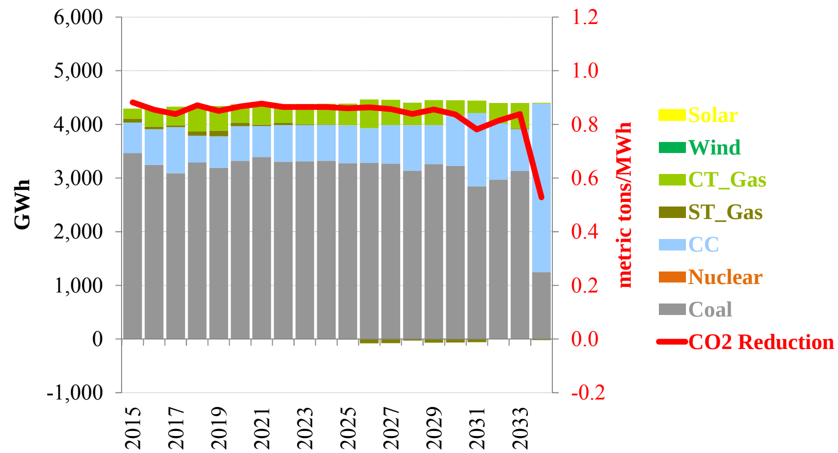

**See Appendix for a description of the Base Case scenario**

# Emission Displacement Results – Base Case (2)

**Generation Displaced by Type**
**Increased Exports - Low**




**Generation Displaced by Type**
**Increased Exports - High**




- **Displaced generation has very similar composition in the High and Low Export cases**
  - Up to ~2030, around 70% of displaced generation is coal, with most of the remainder being gas CC/CT generation, generally reflecting MISO's marginal generation mix
  - Displacement is mostly due to reduced operation of existing generating capacity, not from changing capacity additions/retirements
    - New gas CT capacity is delayed somewhat by the additional hydro capacity, but coal retirements are driven by EPA regulations, not hydro
- **Minor variability in early years is not attributable to incremental hydro**
  - Some coal and gas units have similar dispatch cost, and cross over in dispatch order
  - Small changes in system conditions can result in gas/coal substitution among units with very similar cost but different emissions – causing variability in emission displacement



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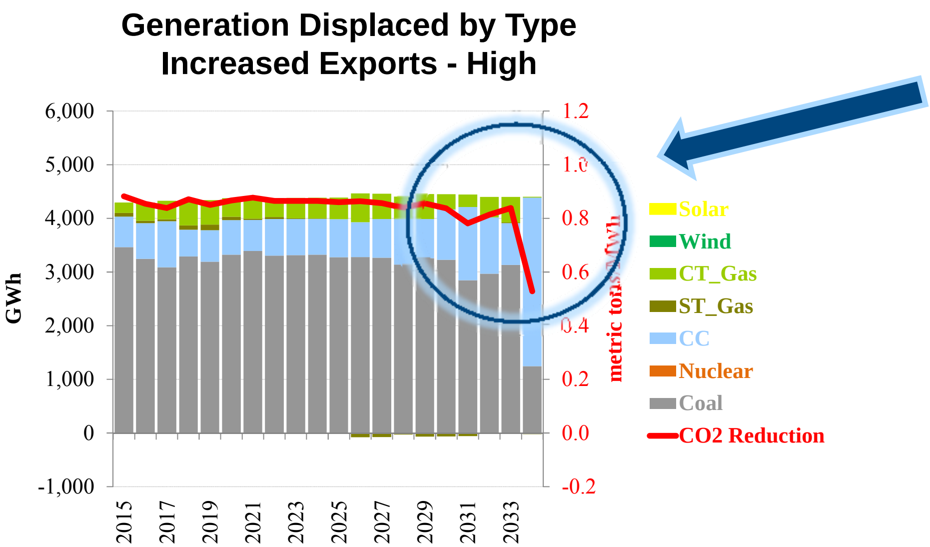
# Emission Displacement Results – Long Run



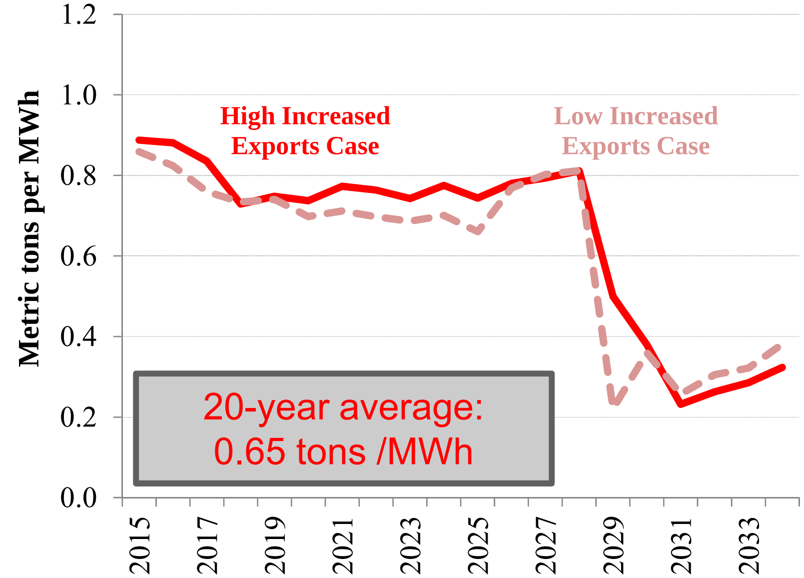

- **Starting around 2030, nuclear plants retire, replaced with gas (mostly CC)**
  - Increased hydro exports can delay CC additions, which makes gas a bigger share of displaced generation
  - As a result, avoided $CO_2$ emissions fall somewhat and may be more variable in later years (it depends on how much CC capacity is delayed in a given year)

- **Beyond 2030, displacement drops off, ultimately toward that of gas CC (~0.4t/MWh)**
  - The primary reason is that in the long run, hydro delays addition of new generation
  - Since new generation is mostly gas CC (in the Base Case), displaced generation and emissions are ultimately like those of a gas CC
- **Displacement in later years may also be variable, changing year by year**
  - Hydro exports delay CC addition or accelerate coal retirement, relative to case with no increased exports
  - The relative amounts of CC delay vs coal retirement acceleration differ somewhat year-by-year, causing corresponding variability in annual emission displacement

# Sensitivity Analysis: High $CO_2$ Price Scenario

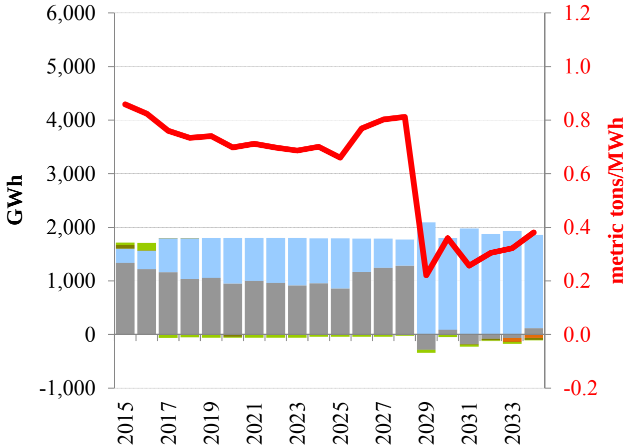
- **In an alternative market scenario with High $CO_2$ Price and a move toward lower-carbon generation, hydro exports displace less MISO $CO_2$, dropping to ~0.70 to 0.75 tons/MWh once $CO_2$ price takes effect**
  - Also accelerates by a couple years the eventual drop to even lower displacement
- **Emission displacement is somewhat more variable than in Base Case, and likely lower – much inefficient coal is retired or pushed up the supply curve, so gas is displaced more often**
  - High $CO_2$ price upends traditional dispatch order of coal mostly below gas
  - Supply curve is quite flat, with coal and gas having similar dispatch costs; they “cross over” thoroughly in dispatch rank
  - Emission displacement similar to gas CC after ~2030

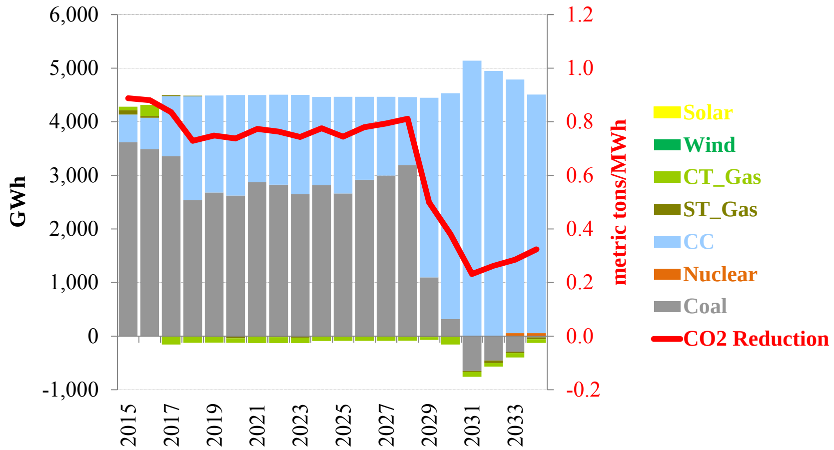
**System $CO_2$ Emissions – Displacement Rate (Annual Average – Peak and Off-Peak)**




**See Appendix for a description of the High $CO_2$ Price scenario**

# Sensitivity Analysis: High $CO_2$ Price Scenario (2)



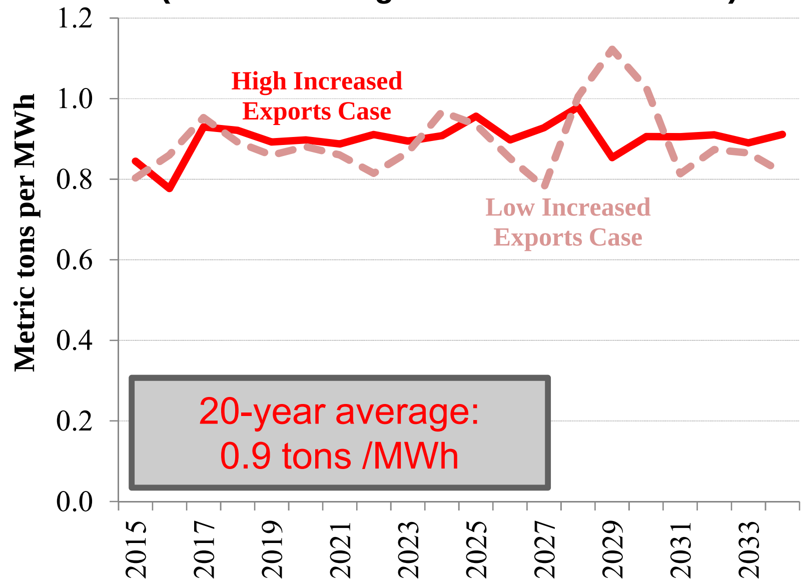




- **Displaced generation has more gas in the mix (compared to Base Case)**
  - Additional hydro exports delay some gas capacity and cause some additional coal retirement
  - Displaced energy is a mix of coal and gas, less coal-heavy, but still mostly coal until late 2020s
- **By late 2020s, emission displacement (and timing of changes) becomes more difficult to predict with confidence**
  - Dropoff seen in displacement (to even below gas rate) is caused by deferral of new CC capacity, which may cause temporary increased reliance on existing coal. This behavior is hard to predict reliably; it depends on how hydro imports affect the specific timing of retirements and additions.
  - In the very long run (ca 2040), additional hydro exports may delay new nuclear additions, causing emissions displacement to drop further

# Sensitivity Analysis: Extreme Low Scenario

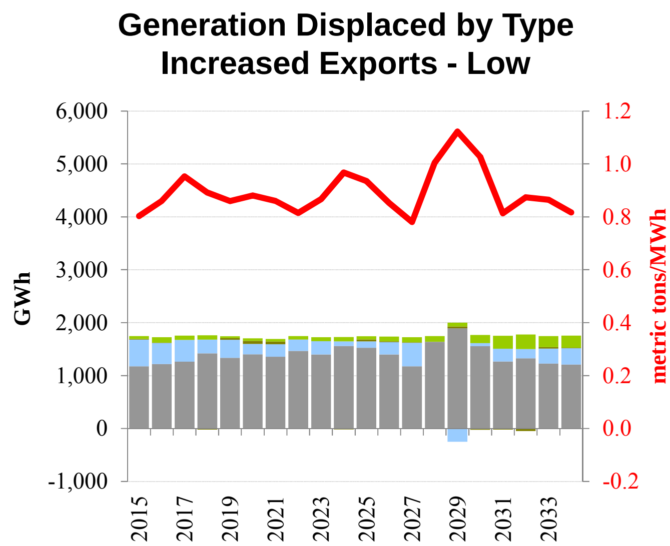
- **In another alternate market scenario with very low power prices (cheap gas, no $CO_2$ price) and a high-carbon generation fleet, incremental hydro exports offset MISO $CO_2$ emissions by slightly more than in Base Case; ~0.9 tons/MWh**
  - Displaced emissions are primarily from high-emissions coal generation, since MISO remains heavily coal-dominated
  - Absence of $CO_2$ price (and lower coal price) keeps coal mostly below gas in the dispatch order, despite low gas price in this case
- **Again, the Low and High Increased Exports cases have similar results**
  - Year-to-year variability is due to energy switching between particular coal and cheap gas resources that happen to have very similar dispatch costs
  - Not directly attributable to hydro exports

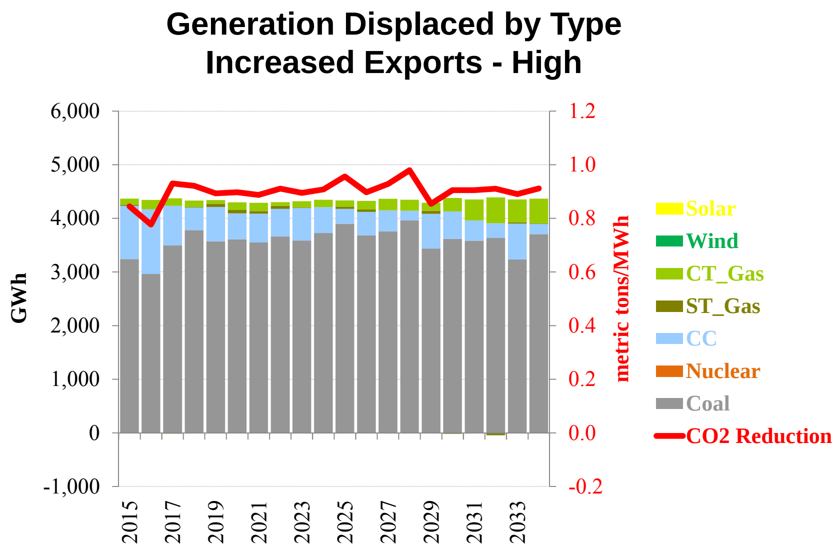
**System $CO_2$ Emissions – Displacement Rate (Annual Average – Peak and Off-Peak)**




**See Appendix for a description of the Extreme Low scenario**

# Sensitivity Analysis: Extreme Low Scenario (2)




- **Displaced generation is predominately coal**
  - MISO remains heavily coal-dominated throughout the horizon, in the absence of a CO2 price
  - Coal stays mostly below gas in the dispatch order, despite low gas price in this case
- **Only very late in the horizon – circa 2040 – does the displacement drop off significantly**
  - Eventually, it decreases toward (though not below) the emissions rate of a gas CC, since the additional hydro capacity ultimately delays the entry of gas CC capacity



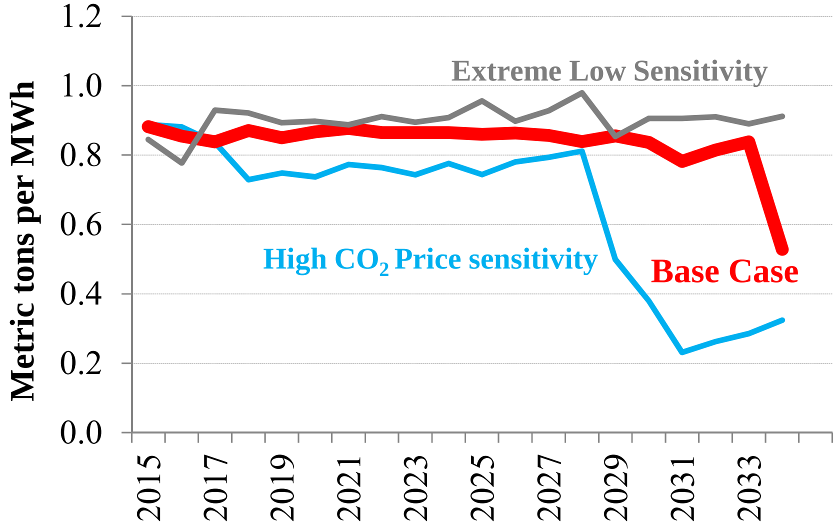
The Brattle Group

# Conclusions

# Conclusions: Emission Displacement

- **In the Base Case, exports displace ~0.85 tons $CO_2$ per incremental MWh**
  - Mostly of the energy displaced is coal
  - Alternative market scenarios may influence this somewhat, most significantly in an extreme case where MISO moves sharply away from coal
  - Even in this scenario, displacement is near that of coal to late 2020s
- **The results are not sensitive to the quantity of additional exports**
- **In some circumstances, emission displacement can be variable and more difficult to predict**
  - Modest variability in near term due to short-term coal/gas substitution when dispatch economics are comparable
  - More variable in the longer term; gas is a larger, more variable share when gas CC additions are being delayed by exports

**Average Reduction in System $CO_2$ Emissions**
**High Increased Exports Cases**



# Conclusions: Emission Drivers and Trends

**Given that MISO is coal-dominated, additional exports will often displace coal, giving high emission displacement similar to the emissions rate of coal**

- In a Base Case future, this is likely to persist for some time, gradually transitioning toward displaced gas CC generation with lower emission displacement
- An alternate scenario where MISO becomes significantly less coal-dependent could lead to less coal (and more gas) being displaced, for a lower displacement rate
  - E.g., in a future with high coal retirements and/or high $CO_2$ price, displacement may be moderately lower in the medium term (to late 2020s), and transition sooner to displacement rate similar to that of gas CC, depending how quickly the system moves toward lower-$CO_2$ generation
- A high-carbon scenario (no CO2 price, few coal retirements) would lead to a higher emission displacement rate than in the Base Case
  - But if it is higher, it is not likely to be much higher – coal already dominates in the Base Case and could not be a much larger share of displaced generation, regardless of the scenario
- Given current information, near- to medium-term displacement is likely to remain high, but there may be a greater chance of lower displacement rates for dates farther in the future
  - I.e., over a longer timeframe, there may be greater opportunity for MISO to shift away from coal, and/or to implement a high $CO_2$ price, which would reduce emission displacement

# Conclusions: Variability in Emissions Displacement

**The variability seen in emissions displacement – modest before ~2030, and potentially greater thereafter – occurs because power markets are driven by economic rankings, but emissions are not ranked in the same way**

- Coal and gas can have similar economics, often "crossing over" in the economic ordering, but have very different emissions
- This is true both in the short run for dispatch, and long run for capacity (long-run economics of operating an existing coal plant may be similar to a new gas CC)

**Slightly different system conditions (e.g., with vs without increased hydro exports) may thus cause switching between coal and gas, driven by very small economic differences**

- This can lead to variability in emissions results when comparing one model run to another; it can be fairly pronounced within short time periods, though tends to average out over a longer horizon
- Markets behave similarly in response to small economic differences – though these are difficult to predict reliably

**Use the model results for general guidance, approximate values, and trends**

- But avoid reading too much into the precise values or year-to-year variations

# Conclusions: Timing of Exports

**The precise timing of exports – e.g., peak vs off-peak, or among finer sub-periods – may modestly affect emission displacement in the Base Case**

- The effect is not pronounced, because the MISO supply curve is relatively flat, and coal and gas “cross over” in the economic ranking
  - About a quarter of coal capacity dispatches above the cheapest gas; a slightly larger share of gas capacity dispatches below the most costly coal (at Base Case fuel and $CO_2$ prices)
- Generation displaced in any sub-period is likely to be a mix of generation types, and have a blended emissions rate
- Shifting energy between peak and off-peak means trading one mix of coal and gas energy for a somewhat different mix, for only a modest overall effect

**There is some variability in emission displacement between particular sub-periods (see previous page)**

- But much of this averages out when aggregated to larger sub-periods, such as annual peak vs off-peak periods

**In an alternative scenario, and/or the far in future, timing could have a more significant effect**

- E.g., if gas were on the margin in all peak hours, and coal in all off-peak hours

# Conclusions: Firm Sales vs Spot Sales

**Whether exports are made as firm sales vs spot transactions would likely have little effect on emissions**

- Would not affect dispatch, which can be optimized in the short term regardless of firm sales agreements

**There might be a slight effect on emissions, if a long-term contractual sale were to influence what other capacity in MISO was added or retired**

- E.g., a coal plant owner might decide to shut down its plant if it had a long-term contract with Manitoba Hydro, whereas in the absence of a firm contract, might keep it operating for reliability
- Even here, however, this would likely apply only to a coal plant with marginal economics, and such a plant would probably dispatch infrequently, so the effect would most likely be modest

# Discussion of Power Market Drivers

**Following are general observations about the effects of some key power market drivers on emission displacement. Some of these factors were not examined directly in this emission displacement study (i.e., did not differ between the three scenarios). Nonetheless, it is possible to make some informed judgments as to their likely effects.**

**Gas Price**

Changes in the gas price could affect emission displacement, if it affects the dispatch order (simultaneously accounting for $CO_2$ price and coal price). But there is sufficient diversity in the efficiencies of both coal and gas generators that there will be no sharp line where coal and gas reverse in the dispatch order at some critical gas price. As gas price falls relative to coal (or as $CO_2$ price rises), gas and coal intermingle more and more in the dispatch order. This suggests that gas prices might reduce emission displacement in a scenario with such a low gas price that it prompted truly massive coal retirements and replacement with gas CC capacity. Very high gas prices might ensure that gas would be on the margin only infrequently, since coal retirements would be suppressed and MISO load growth is low; this might raise emission displacement slightly. But modest gas price changes are likely to have a limited effect.

# Discussion of Other Potential Factors (2)

**$CO_2$ Price**

Similar to the effect of gas price discussed above, different $CO_2$ price levels could affect emission displacement, to the extent they affect dispatch order (accounting for gas and coal prices). The crossover of coal and gas in the dispatch order as their relative economics change ensures there will be no sharp line where the dispatch order reverses at some critical $CO_2$ price, though the sudden imposition of a material $CO_2$ price would of course have a big effect. Extremely high $CO_2$ price that forces massive coal retirements and replacement with gas and/or renewables could suppress the displacement, though that seems politically unlikely.

**MISO Load**

Emission displacement is unlikely to be significantly affected by MISO load levels. Load would need to change quite dramatically to have a major effect on the overall generation mix or the marginal generation. Given that load is forecast to grow very slowly (below 1%; even less in the Base Case), it seems unlikely that overall load would change by enough to have a substantial effect on emission displacement.

# Discussion of Other Potential Factors (3)

**Renewable Generation**

Since renewables (wind, solar) dispatch at the bottom of the supply curve, they are unlikely to affect emission displacement directly (renewables would be displaced directly only if the system is curtailing excess renewable energy, which is unlikely to occur with substantial frequency). By shifting the supply curve to the right, additional renewables can change what is on the margin. Similar effects might be seen with large additions of coal with carbon capture or nuclear capacity. The effect on emissions could be significant in scenarios where coal and gas are strongly segregated (e.g., by high gas price with no $CO_2$ price), or if there are also large changes in the generation mix (e.g., significant additional gas capacity additions or coal retirements).

**Nuclear Retirements**

As above for renewable generation, nuclear is at the bottom of the supply curve and will almost never be directly displaced, so additional nuclear retirements would have almost no direct effect. They could have some influence in circumstances similar to those described above, though the effects would be opposite since retirements shift the supply curve to the left.

# Appendix:

# ReCap Model
# and Scenario Descriptions

# Appendix:
# Simulation Modeling – ReCap Model

**Scenarios analyzed using ReCap (Regional Capacity Expansion) which is a high-level capacity expansion simulation model**

- Use of a simple model facilitates "seeing the forest beyond the trees"

**ReCap was developed by The Brattle Group and has been used in numerous studies, including several previous power price forecasts for Manitoba Hydro**

- Simulation and optimization model - minimizes total cost of serving load (as do markets, sort of)
  - Has perfect foresight (certain future) in a given scenario; multiple scenarios are simulated
- Simplified system characterization:
  - Load profile characterized with an 18-step seasonal load duration curve constructed from hourly load shape
  - Each type of dispatchable generation is divided into several classes with similar dispatch characteristics, by sub-region – e.g., coal with 10,000 heat rate, coal with 10,500 heat rate, etc.
  - Hourly wind profile (specific to each sub-region) captures temporal relation to load
  - Six sub-regions modeled, with no internal constraints but transmission interconnections with others
- Simulation and optimization
  - Online capacity in each given year is operated to serve energy load
  - New capacity is added if necessary to meet peak load plus reserve margin requirement (~15%)
    - Most economic type of capacity is added (beyond reserve requirement, if enough energy value)
  - Additional renewable capacity (mostly wind) is added to meet RPS goals, at several alternative levels
  - Generator operation and type and timing of new capacity additions and retirements are simultaneously optimized over the full horizon, to minimize cost
    - Accounting for capital costs and fixed and variable operating costs (fuel, $CO_2$, FOM, VOM)
    - Capacity additions are continuous – not lumpy additions of large plant
    - Capacity will be retired if energy margins and capacity value fail to cover to-go costs

# Appendix:
# ReCap Model (cont'd)

**Some of the capabilities of ReCap include:**

- Seasonal modeling
  - Including load, outages, hydro production, seasonal generating capacity, imports from Manitoba
  - Wind energy output profile, based on hourly wind profile data at a regional level (incorporated as a reduction to gross load; dispatchable fleet serves net load after wind generation is accounted for)
- Transmission limits modeled between sub-regions (simple "pipes" model); no constraints within sub-region
- Based on load forecast and capacity data from EIA's 2013 Annual Energy Outlook (AEO) Early Release. Underlying generation characteristics mostly from Ventyx, the Velocity Suite.

**ReCap does <u>not</u> include:**

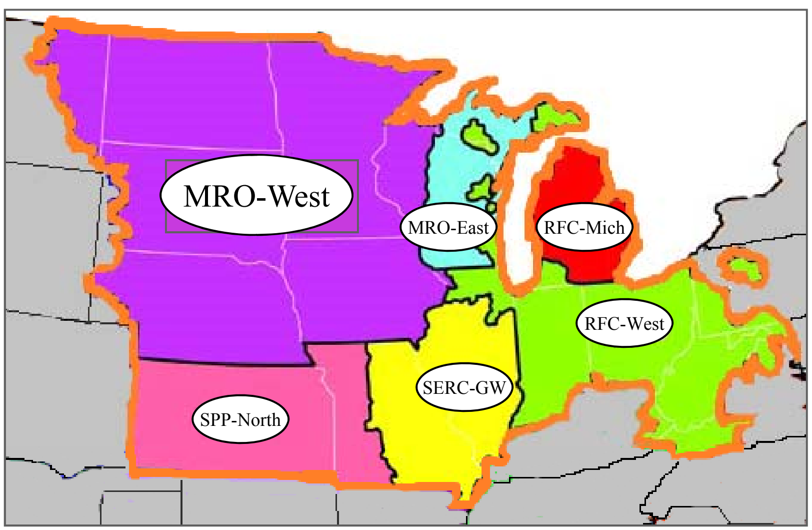
- Operational constraints such as unit commitment costs (e.g., start-up, min-load costs) and ancillary services
  - Actual market prices may differ due to these factors. Operational constraints may cause market prices to be lower off-peak, higher on-peak, and overall more volatile, than simulated by a model like ReCap.
  - ReCap was recently improved to capture these effects to some extent
- Strategic bidding behavior, which can raise prices above fully competitive levels
- Randomized forced outages, which can cause significant short-term price volatility
- Non-$CO_2$ pollutant costs and environmental upgrades
  - Variable cost of non-$CO_2$ emissions is modest, relative to major drivers of energy prices
  - Capital costs of upgrades are unlikely to have a major effect on energy prices in a marginal-bid wholesale market. Coal retirements due to potential stricter requirements are considered.
- While these factors can be important in particular hours, their overall impacts are generally modest, and unlikely to affect overall prices (and long-term investment strategy) significantly
  - Could plausibly amount to a few dollars per MWh

# Appendix:
# ReCap Model – Implementation

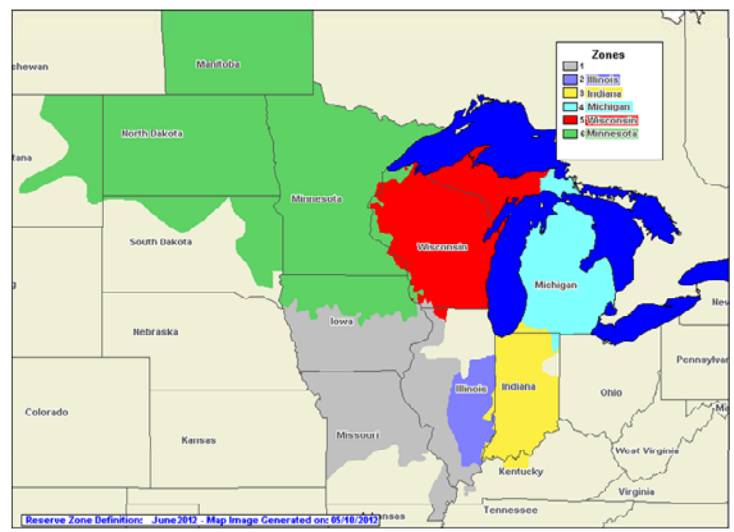
## MRO-West sub-region is primary interest for pricing

- MRO-West footprint is similar to MISO's reserve zone 7 and MAPP : Most or all of Minnesota, Iowa, North and South Dakota, Nebraska, parts of Montana, Wisconsin
  - Transmission constraints within the sub-regions and local congestion are not modeled
- Also model neighboring sub-regions, with dynamic transmission flows between: MRO-East, RFC-West, RFC-Michigan, SPP-North, SERC-Gateway
  - Aggregate 2013 peak for 6 sub-region area is about 180 GW (non-coincident)
  - Aggregate existing generating capacity is 261 GW (nameplate)

**Region Modeled (MRO-West Focus)**

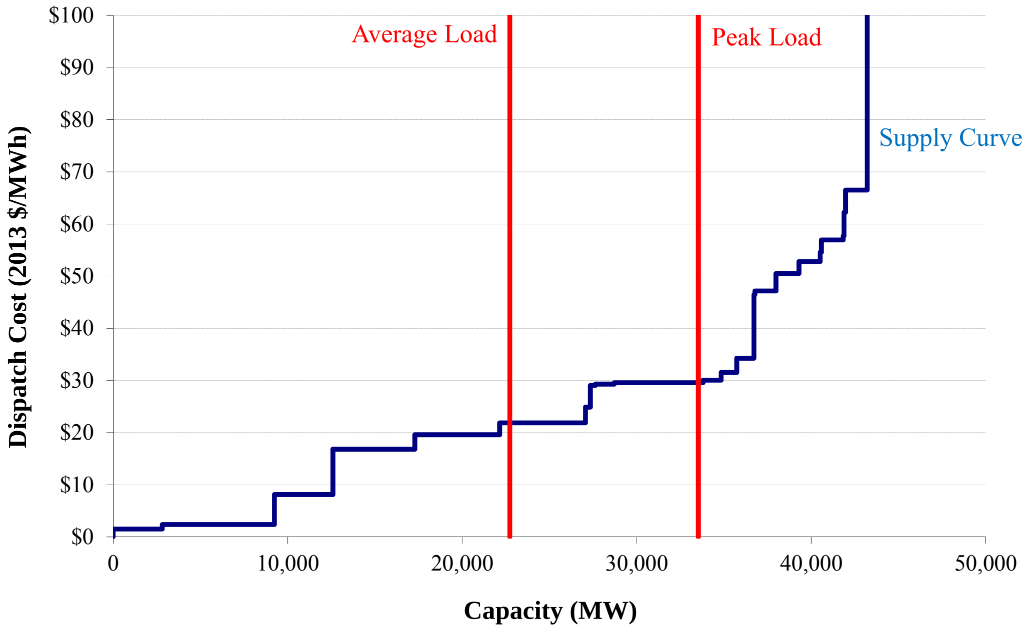



**MISO Reserve Zones**



# Appendix:
# ReCap Model – Implementation

MRO-West Existing Supply Curve




**Note:** Capacity adjusted for forced outages; wind based on average capacity factor

## Starting system characterization

- Existing generating capacity and performance parameters (from AEO 2013, Ventyx Inc.) characterized for each region
  - Generation characterized as "classes" of capacity with similar operating attributes (e.g., 4 coal classes per sub-region)
- Load forecast – AEO 2013 provides starting point
  - Price elasticity adjustments and DSM programs are included in scenarios
- Gas price – base forecast from recent futures prices; assumed high & low values in scenarios
- Coal price – based on AEO data
- Renewables – current state RPS requirements, potential federal RPS (higher)
- Climate legislation ($CO_2$ price) – several trajectories examined
  - Also considered non-price mechanisms
- New generation technologies: cost, performance, and availability
  - AEO assumptions for cost and performance parameters

# Appendix:
# Scenario Descriptions

**Emission displacement was evaluated in the context of the Base Case market scenario**

- It was also evaluated under two alternative market scenarios, to test the sensitivity of emission displacement to differing market conditions

**Each of the market scenarios was developed by combining key effects on power prices**

- Fuel prices, coal retirements, climate policy ($CO_2$ price), renewable generation, transmission expansion, load growth are the primary factors
- The two sensitivity scenarios, along with the Base Case, together give a broad view of potential power market conditions*

| Scenario Name | Natural Gas Price | $CO_2$ Price | Renewable Additions | MISO Load Growth | Coal Retirement (MRO-West) |
|---|---|---|---|---|---|
| **BASE CASE** | Base<br>\$4.4 → ~\$7 | Base<br>\$15.7 in 2020, +3%/yr | Meet State RPS<br>~12% by 2025 | 20-year Average<br>Growth 0.1% | Moderate<br>4.3 GW by 2020 |
| **High $CO_2$** | Base<br>\$4.4 → ~\$7 | High<br>\$25 in 2018, +5%/yr | Meet State RPS<br>~12% by 2025 | 20-year Average<br>Growth -0.1% | Moderate<br>4.3 GW by 2020 |
| **Extreme Low** | Low<br>\$3 → ~\$4 | Zero $CO_2$ price | Meet State RPS<br>~12% by 2025 | 20-year Average<br>Growth 0.5% | Low<br>0.4 GW by 2020 |

*** Note:** This set of scenarios does not encompass all possible outcomes, and does not necessarily contain the most extreme outcomes possible

# Appendix:
# Base Case Scenario – Key Assumptions

**The Base Case scenario represents a continuation of current trends; essentially all input factors meet current expectations**

- AEO 2013 Reference Case used as a starting point, but some factors differ
- $CO_2$ price starts at $16/ton in 2020, grows at 3% to $21/ton in 2030, reaching $28/ton by 2040
- Fuel price updated to market outlook (early 2013)
  - Natural gas: $4.4/MMBtu in 2015, to $5.9/MMBtu in 2025 (slightly above AEO)
  - Coal: $1.7/MMBtu in 2015, to $2.0/MMBtu in 2025 (AEO projections)
- Demand adjusted downward – elasticity response to higher prices (mostly $CO_2$)
  - Peak growth rate is roughly half that of the AEO Reference Case
  - Energy demand essentially flat starting in 2020 when $CO_2$ price manifests
- New generation additions:
  - Renewable additions are based on existing state RPS requirements, and include ~5,000 MW new wind generation in MRO-W for export (mainly into RFC-West)
  - New conventional generation already under construction is added at its expected online year (MRO-W adds no new coal and 150MW new gas CT; more elsewhere)
  - Nuclear becomes available in 2026, additions limited to 1,000 MW/year
- Planned unit retirements:
  - ~21% of the existing MRO-W coal capacity retires by 2020 to comply with EPA regulations that are expected to be in place (23% across all 6 sub-regions modeled)
  - Nuclear plants assumed to retire after 60 years of operation (Kewaunee in 2013)

# Appendix:
# High $CO_2$ Price Scenario – Key Assumptions

**This scenario represents a future in which persistently higher $CO_2$ prices prevail (e.g., due to a relatively stringent U.S. climate policy) in an environment otherwise similar to the Base Case**

- Higher $CO_2$ price – starts at $25/ton in 2018, grows at 5% to $57/ton in 2035
  - Although higher than the $CO_2$ price assumed in the Base Case, this is not extremely high, particularly in comparison with what might have been deemed possible a few years ago
- Demand is lower in the long-term – greater elasticity response to higher retail prices ($CO_2$ price adder, plus wind capital costs)
  - Peak and energy levels similar to the Base Case through 2021, then decline gradually at ~0.2% per year
- Other inputs similar to Base Case
- Power prices are significantly higher than Base Case, primarily due to $CO_2$ price

# Appendix:
# Extreme Low Scenario – Key Assumptions

**This scenario reflects a failure to enact any climate policy (zero $CO_2$ price), while additionally, gas prices are assumed to be very low (e.g., due to significant technological improvements in shale gas production methods). These price-depressing factors are not necessarily related, but could plausibly occur together, and would lead to very low power prices if they did.**

- No $CO_2$ price – climate policy not implemented
- Lower gas price – \$2.9/MMBtu in 2015, and \$3.6/MMBtu in 2025
  - Below current near-term prices and recent expectations, but not unprecedented
  - Coal prices are also lower, which might be prompted by low gas prices
- Demand grows at a modest 0.5% per year –results in projections higher than the Base Case, and slightly above the AEO 2013 Reference Case
- Lower "forced" coal plant retirements than Base Case – in response to better energy margins under zero $CO_2$ prices
  - ~2% of existing coal generation retires by 2020 to comply with EPA regulations that are expected to be in place (~10% across all 6 sub-regions modeled)
- Other inputs similar to Base Case
- Power prices are significantly lower than Base Case, due to the combination of low price drivers

# Contact Information

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Dr. Murphy is an engineer and economist with expertise in energy, competitive, and regulatory economics and finance, as well as quantitative modeling and risk analysis. His work focuses on the electric power industry, encompassing areas such as resource and investment planning (including price forecasting), valuation for contract disputes and asset transactions, climate change policy and analysis, competitive industry structure and market behavior, and market rules and mechanics.

He has addressed these issues in the context of business planning and strategy, regulatory hearings, and litigation and arbitration. His clients include investor-owned and public electric utilities, independent power producers, developers and investors, competitive suppliers, industry groups, regulators, and system operators.

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**SUBJECT: Rate Impacts**

**REFERENCE: Chapter 11 Financial Evaluation of Development Plans; CAC/MH I-140; CAC/MH I-165; CAC/MH I-181a; CAC/MH I-191b**

**PREAMBLE:** CAC wishes to understand the rate impacts, bill impacts and relative affordability of electricity compared to other Provinces for average and low income residential customers resulting from the preferred and alternative plans.

**QUESTION:**

The Minister of Finance 2013 Report under The Affordability Utility Rate Act was Tabled in the Legislature on August 26 2013. Please use the data in response CAC/MH I-140 to generate a Table(s) that show(s) the rate impacts for the Preferred Plan as follows:

(i) 2015-2025 by year, the average residential rates;

(ii) bill impacts by year for residential electric heating customer per response CAC/MH I-191b;

(iii) similar bill impacts for low income customer using (defined) Manitoba Hydro LI threshold for DSM .

**RESPONSE:**

Please see the tables below for the data as requested in i), ii) and iii). Please note that the annual kWh usage for the low income customer group (LICO-125) provided in response to part iii), is based on electric heat services, to be consistent with the consumption levels reported in response to CAC/MH I-191(b).

| **Preferred Plan** | **Residential Rates** | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| K19 Exp C25 750mw | Monthly Basic Charge: | $7.63 | $7.93 | $8.24 | $8.57 | $8.91 | $9.26 | $9.63 | $10.01 | $10.41 | $10.82 | $11.25 |
| | Energy Charge (per kWh): | $0.0772 | $0.0802 | $0.0834 | $0.0867 | $0.0901 | $0.0937 | $0.0974 | $0.1012 | $0.1052 | $0.1094 | $0.1137 |

| | **Single Detached** | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Income Range: | Annual kWh Usage (Electric Heat Billed) | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
| Under $25,000 | 23,233 | $1,885 | $1,958 | $2,037 | $2,117 | $2,200 | $2,288 | $2,378 | $2,471 | $2,569 | $2,672 | $2,777 |
| $25,000 - $49,999 | 28,146 | $2,264 | $2,352 | $2,446 | $2,543 | $2,643 | $2,748 | $2,857 | $2,968 | $3,086 | $3,209 | $3,335 |
| $50,000 - $74.999 | 29,316 | $2,355 | $2,446 | $2,544 | $2,645 | $2,748 | $2,858 | $2,971 | $3,087 | $3,209 | $3,337 | $3,468 |
| $75,000 - $99,999 | 31,902 | $2,554 | $2,654 | $2,760 | $2,869 | $2,981 | $3,100 | $3,223 | $3,349 | $3,481 | $3,620 | $3,762 |
| $100,000 plus | 32,254 | $2,582 | $2,682 | $2,789 | $2,899 | $3,013 | $3,133 | $3,257 | $3,384 | $3,518 | $3,658 | $3,802 |
| **Overall** | **28,574** | $2,297 | $2,387 | $2,482 | $2,580 | $2,681 | $2,789 | $2,899 | $3,012 | $3,131 | $3,256 | $3,384 |
| **LICO-125** | **24,317** | $1,969 | $2,045 | $2,127 | $2,211 | $2,298 | $2,390 | $2,484 | $2,581 | $2,683 | $2,790 | $2,900 |

| | **Multi-Attached** | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Income Range: | Annual kWh Usage (Electric Heat Billed) | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
| Under $25,000 | 16,152 | $1,338 | $1,391 | $1,446 | $1,503 | $1,562 | $1,625 | $1,689 | $1,755 | $1,824 | $1,897 | $1,971 |
| $25,000 - $49,999 | 15,261 | $1,270 | $1,319 | $1,372 | $1,426 | $1,482 | $1,541 | $1,602 | $1,665 | $1,730 | $1,799 | $1,870 |
| $50,000 - $74.999 | 17,271 | $1,425 | $1,480 | $1,539 | $1,600 | $1,663 | $1,729 | $1,798 | $1,868 | $1,942 | $2,019 | $2,099 |
| $75,000 - $99,999 | 17,546 | $1,446 | $1,502 | $1,562 | $1,624 | $1,688 | $1,755 | $1,825 | $1,896 | $1,971 | $2,049 | $2,130 |
| $100,000 plus | 15,882 | $1,318 | $1,369 | $1,423 | $1,480 | $1,538 | $1,599 | $1,662 | $1,727 | $1,796 | $1,867 | $1,941 |
| **Overall** | **16,346** | $1,353 | $1,406 | $1,462 | $1,520 | $1,580 | $1,643 | $1,708 | $1,774 | $1,845 | $1,918 | $1,994 |
| **LICO-125** | **15,923** | $1,321 | $1,372 | $1,427 | $1,483 | $1,542 | $1,603 | $1,666 | $1,732 | $1,800 | $1,872 | $1,945 |

| Income Range: | **Apartment Suite** Annual kWh Usage (Electric Heat Billed) | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Under $25,000 | 7,946 | $705 | $732 | $762 | $792 | $823 | $856 | $890 | $924 | $961 | $999 | $1,038 |
| $25,000 - $49,999 | 8,847 | $775 | $805 | $837 | $870 | $904 | $940 | $977 | $1,015 | $1,056 | $1,098 | $1,141 |
| $50,000 - $74.999 | 9,330 | $812 | $843 | $877 | $912 | $948 | $985 | $1,024 | $1,064 | $1,106 | $1,151 | $1,196 |
| $75,000 - $99,999 | 10,711 | $918 | $954 | $992 | $1,031 | $1,072 | $1,115 | $1,159 | $1,204 | $1,252 | $1,302 | $1,353 |
| $100,000 plus | 12,668 | $1,070 | $1,111 | $1,155 | $1,201 | $1,248 | $1,298 | $1,349 | $1,402 | $1,458 | $1,516 | $1,575 |
| **Overall** | **8,969** | $784 | $814 | $847 | $880 | $915 | $952 | $989 | $1,028 | $1,068 | $1,111 | $1,155 |
| **LICO-125** | **7,608** | $679 | $705 | $733 | $762 | $792 | $824 | $857 | $890 | $925 | $962 | $1,000 |

**SUBJECT: Rate Impacts**

**PREAMBLE:** CAC wishes to understand the rate impacts, bill impacts and relative affordability of electricity compared to other Provinces for average and low income residential customers resulting from the preferred and alternative plans.

**QUESTION:**

The Minister of Finance 2013 Report under The Affordability Utility Rate Act was Tabled in the Legislature on August 26 2013. Please provide a comparison of future Manitoba Hydro, BC, Sask and PQ electricity costs for 2015-2025 in both tabular and chart form based on Annual Basic Utility Bundle Cost Comparison (found on the page 2 of this document) and assuming the following (i) Manitoba Hydro electricity costs start in 2013 at $844/yr and escalate as per Preferred Plan from 2015-2025; (ii) BC, Saskatchewan and Quebec electricity prices escalate at the rate of Canadian Deflator (CAC/MH I-150) (iii) all provincial natural gas and auto insurance costs increase at the Canadian Deflator. Please show the Deflator on the chart and in the Table show also the 2025 Totals and Gap from Manitoba.

## Annual basic utility bundle cost comparison for the year ended March 31, 2013

This annual summary provides a comparison of the cost of a bundle of Manitoba's basic utility services with the cost of that same bundle in other Canadian provinces during the year ended March 31, 2013. The bundle includes electricity, natural gas (home heating) and auto insurance services. The comparative costs were developed based on a methodology developed by Deloitte LLP.

| Province | Electricity (non-electric heat) | Natural gas (home heating) | Automobile insurance | Total | Gap from Manitoba |
|---|---|---|---|---|---|
| British Columbia | $1,007 | $845 | $1,472 | $3,324 | $593 |
| Alberta | 1,768 | 618 | 2,491 | 4,877 | 2,146 |
| Saskatchewan | 1,496 | 744 | 1,168 | 3,408 | 677 |
| Manitoba | 844 | 735 | 1,152 | 2,731 | - |
| Ontario | 1,494 | 792 | 5,380 | 7,666 | 4,935 |
| Quebec | 756 | 1,327 | 1,356 | 3,439 | 708 |
| New Brunswick | 1,342 | 2,254 | 1,882 | 5,478 | 2,747 |
| Nova Scotia | 1,687 | 2,372 | 1,708 | 5,767 | 3,036 |
| Prince Edward Island | 1,652 | 2,547 | 1,828 | 6,027 | 3,296 |
| Newfoundland | 1,406 | 2,462 | 1,707 | 5,575 | 2,844 |
| **Average** | **$1,345** | **$1,470** | **$2,014** | **$4,829** | **$2,098** |

## Utility bundle component calculation summary

### Electricity

The annual cost of electricity for each province is the weighted average[1] of the annual cost of electricity for each of two centres surveyed in the province. The annual cost of electricity for each of the two centres surveyed in each province, one urban and one rural, is based on monthly electricity utilization that reflects actual Manitoba experience for non-electric heat residential customers, multiplied by the actual monthly rates in effect for that centre. Manitoba electricity utilization experience reflected in the 2013 results is 11,075 kWh per year.

### Natural gas (home heating)

The annual cost of home heating for each province is the weighted average[1] of the annual cost of natural gas heating for each of two centres surveyed in the province. The annual cost of natural gas for each of the two centres surveyed in each province, one urban and one rural, is based on monthly natural gas utilization that reflects actual Manitoba experience for residential customers, multiplied by the actual monthly rates in effect for that centre. Manitoba natural gas utilization experience reflected in the 2013 results is 2,427 cubic metres per year. In a limited number of centres surveyed, where natural gas is not available, a heat equivalent amount of heating oil is utilized as the basis for calculating the annual cost of heating.

### Auto insurance

The annual cost of auto insurance for each province is the weighted average[1] of the annual cost of auto insurance in each of two centres surveyed in the province. The annual cost of auto insurance in each centre, one urban and one rural, is based on the average of the cost of annual insurance coverage for a sample of ten vehicle/driver/coverage profiles. The ten vehicle/driver/coverage profiles were developed to reflect the most popular vehicles insured in Manitoba and proportional representation of actual driver ages, driver safety ratings and insurance coverage purchased for passenger vehicles in Manitoba.

[1] Weighting is between costs in the two sample centres, one urban and one rural, based on data published by Statistics Canada in their 2011 survey of "Private Dwellings occupied by usual residents" for each province.

 Annual Basic Utility Bundle Cost Comparison – March 31, 2013

**RESPONSE:**

The GDP deflator rate assumed in the preamble to this Information Request is considerably less than the average rate increases being proposed for these three utilities. The GDP deflator is a general measure of the cost changes of all goods and services produced in a country. In general, utilities across Canada have been experiencing cost increases greater than the rate of the GDP price deflator. Thus, where better information is available on the proposed future rate increases for these utilities, Manitoba Hydro has incorporated that information instead of the GDP Deflator proxy.

The British Columbia government has announced electricity rate increases of 9.0% for 2014 and 6.0% for 2015, while the British Columbia Utilities Commission (BCUC) has capped rate increases for BC Hydro in 2016, 2017 and 2018 at 4.0%, 3.5% and 3.0% respectively. The Saskatchewan Rates Review Panel (SRRP) is currently reviewing proposed increases for SaskPower of 5.5% for 2014, and 5.0% in each of the following two years (2015 and 2016). Hydro Quebec is also proposing a rate increase of 3.4% for 2014, which, when incorporated with a proposed increase to their rate of return, will result in an overall average increase of approximately 5.8% this year. As the information provided in the bundled cost comparison was only to March 31, 2013, the approved 2013/14 rate increases for all utilities has also been incorporated as shown in the tables below.

Despite the incorporation of this better information, Manitoba Hydro remains concerned that the the GDP deflator is not reflective of future rates of other utilities, hence this information should be interpreted with caution. Table (i) provides Manitoba Hydro's electricity costs specified in the preamble escalated in accordance with the Preferred Development Plan. Table ii) provides BC, Saskatchewan and Quebec electricity prices escalated in accordance with the rate increases approved or proposed above, and at the GDP deflator thereafter. Table iii) provides the balance of the requested calculations; although Manitoba Hydro notes that it does not have information to suggest the stated assumption is reasonable.

**i) MH electricity costs of $844/yr escalated as per Preferrred Plan**

| Electricity Costs | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| K19 Exp C25 750mw | | 3.50% | 3.95% | 3.95% | 3.95% | 3.95% | 3.95% | 3.95% | 3.95% | 3.95% | 3.95% | 3.95% | 3.95% |
| Manitoba | $844 | $874 | $908 | $944 | $981 | $1,020 | $1,060 | $1,102 | $1,145 | $1,191 | $1,238 | $1,287 | $1,337 |

**ii) BC,Sask, Quebec electricity prices escalated for approved and proposed rate increases and at rate of Cdn Deflator (CAC/MH I-150)**

| Electricity Costs | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cdn GDP Deflator - % chg | | 1.80% | 1.80% | 1.80% | 1.80% | 1.90% | 1.90% | 1.90% | 1.90% | 1.90% | 1.90% | 1.90% | 1.90% |
| Approved & Proposed Rate Increases: | | | | | | | | | | | | | |
| - British Columbia | | 1.44% | 9.0% | 6.0% | 4.0% | 3.5% | 3.0% | | | | | | |
| - Saskatchewan | | 4.9% | 5.5% | 5.0% | 5.0% | | | | | | | | |
| - Quebec | | 2.41% | 5.8% | | | | | | | | | | |
| British Columbia | $1,007 | $1,022 | $1,113 | $1,180 | $1,227 | $1,270 | $1,309 | $1,333 | $1,359 | $1,385 | $1,411 | $1,438 | $1,465 |
| Saskatchewan | $1,496 | $1,569 | $1,656 | $1,738 | $1,770 | $1,803 | $1,838 | $1,872 | $1,908 | $1,944 | $1,981 | $2,019 | $2,057 |
| Quebec | $756 | $774 | $788 | $802 | $817 | $832 | $848 | $864 | $881 | $897 | $914 | $932 | $950 |

**iii) all provincial natural gas & auto insurance costs increase at Cdn Deflator**

| Natural Gas Costs | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cdn GDP Deflator - % chg | | 1.80% | 1.80% | 1.80% | 1.80% | 1.90% | 1.90% | 1.90% | 1.90% | 1.90% | 1.90% | 1.90% | 1.90% |
| Manitoba | $735 | $748 | $762 | $775 | $789 | $804 | $820 | $835 | $851 | $867 | $884 | $901 | $918 |
| British Columbia | $845 | $860 | $876 | $891 | $908 | $925 | $942 | $960 | $978 | $997 | $1,016 | $1,035 | $1,055 |
| Saskatchewan | $744 | $757 | $771 | $785 | $799 | $814 | $830 | $845 | $862 | $878 | $895 | $912 | $929 |
| Quebec | $1,327 | $1,351 | $1,375 | $1,400 | $1,425 | $1,452 | $1,480 | $1,508 | $1,537 | $1,566 | $1,596 | $1,626 | $1,657 |
| **Auto Insurance** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** | **2023** | **2024** | **2025** |
| Cdn GDP Deflator - % chg | | 1.80% | 1.80% | 1.80% | 1.80% | 1.90% | 1.90% | 1.90% | 1.90% | 1.90% | 1.90% | 1.90% | 1.90% |
| Manitoba | $1,152 | $1,173 | $1,194 | $1,215 | $1,237 | $1,261 | $1,285 | $1,309 | $1,334 | $1,359 | $1,385 | $1,411 | $1,438 |
| British Columbia | $1,472 | $1,498 | $1,525 | $1,553 | $1,581 | $1,611 | $1,642 | $1,673 | $1,704 | $1,737 | $1,770 | $1,804 | $1,838 |
| Saskatchewan | $1,168 | $1,189 | $1,210 | $1,232 | $1,254 | $1,278 | $1,303 | $1,327 | $1,352 | $1,378 | $1,404 | $1,431 | $1,458 |
| Quebec | $1,356 | $1,380 | $1,405 | $1,431 | $1,456 | $1,484 | $1,512 | $1,541 | $1,570 | $1,600 | $1,630 | $1,661 | $1,693 |

The table below provides the 2025 totals and the level of cost compared to Manitoba.

| Province | Electricity (non-electric heat) | Natural Gas (home heating) | Automobile Insurance | Total | Increase over Manitoba |
|---|---|---|---|---|---|
| Manitoba | $1,337 | $918 | $1,438 | $3,693 | - |
| British Columbia | $1,465 | $1,055 | $1,838 | $4,358 | $665 |
| Saskatchewan | $2,057 | $929 | $1,458 | $4,444 | $751 |
| Quebec | $950 | $1,657 | $1,693 | $4,300 | $607 |

**SUBJECT: Load Forecast**

**REFERENCE: Chapter 3; Table 3.1; Page No. 5; CAC/MH I-240a**

**PREAMBLE:** Historically, electricity consumption has been associated with economic activity, as measured by real Gross Domestic Product (GDP). A growing economy is associated with increased electricity consumption while economic downturns have a tendency to reduce or stall the growth of consumption. While the correlation between GDP and electricity consumption has been moderated by shifts away from manufactured goods and more towards services, the decrease in North American electricity consumption during the 2008–2009 economic recession demonstrates that overall economic conditions still have a significant impact on electricity consumption."

In Table 3.1, Manitoba Hydro provides the NERC forecast of annual Total Demand Growth Across Regions. In Figure 3.4, Comparison of Forecast GDP, Manitoba Hydro suggests that GDP growth in the US will outstrip GDP growth in Manitoba. At page 6 of the September 5, 2013 powerpoint document Manitoba Hydro Electric Load Forecast, the corporation summarizes its findings related growth in residential load. September 5, 2013 powerpoint document Manitoba Hydro Electric Load Forecast.

**QUESTION:**

The response provided to CAC/MH 1–240a compares the term "total internal demand" employed by NERC to the term "Gross Total Peak" used by Manitoba Hydro. As per the original question, please explain how the definition of the term "total internal demand", as employed by NERC, differs from the term "Load Growth" as employed by Manitoba Hydro.

**RESPONSE:**

As outlined in Mantioba Hydro's response to CAC/MH I-240a, differences in inclusions and exclusions under the NERC definition of "Total Internal Demand" result in an overall lower growth rate than Manitoba Hydro's forecast growth rate based on Gross Total Peak.

Manitoba Hydro's load growth at the system level for demand is defined with respect to Gross Total Peak. Manitoba Hydro's Gross Total Peak is based upon annual peak and includes station service, and excludes projected reductions due to DSM programs, future HVDC line loss reductions and net export sale and purchase losses.

NERC's "Load Growth" is based on their definition of "Total Internal Demand". "Total Internal Demand" is calculated based upon maximum monthly peak and includes reductions due to DSM programs, future HVDC line loss reductions and net export sale and purchase losses, and excludes station service.

**SUBJECT: Load Forecast**

**REFERENCE: Chapter 3; Table 3.1; Page No. 5; CAC/MH I-240b**

**PREAMBLE:** Historically, electricity consumption has been associated with economic activity, as measured by real Gross Domestic Product (GDP). A growing economy is associated with increased electricity consumption while economic downturns have a tendency to reduce or stall the growth of consumption. While the correlation between GDP and electricity consumption has been moderated by shifts away from manufactured goods and more towards services, the decrease in North American electricity consumption during the 2008–2009 economic recession demonstrates that overall economic conditions still have a significant impact on electricity consumption."

In Table 3.1, Manitoba Hydro provides the NERC forecast of annual Total Demand Growth Across Regions. In Figure 3.4, Comparison of Forecast GDP, Manitoba Hydro suggests that GDP growth in the US will outstrip GDP growth in Manitoba. At page 6 of the September 5, 2013 powerpoint document Manitoba Hydro Electric Load Forecast, the corporation summarizes its findings related growth in residential load. September 5, 2013 powerpoint document Manitoba Hydro Electric Load Forecast.

**QUESTION:**

Please confirm that Manitoba Hydro accepts the NERC analysis of Annuals Total Internal Demand Growth for MRO Manitoba as displayed by NERC.

**RESPONSE:**

Manitoba Hydro accepts the NERC values of Annual Total Internal Demand Growth for MRO based upon the definition as outlined in response to CAC/MH II-136. These values have inclusions and exclusions that differ from Manitoba Hydro's Gross Total Peak Forecast that overall results in a lower 10 year average growth rate with the inclusion of DSM program demand reductions being a large part of the difference.

**SUBJECT: Load Forecast**

**REFERENCE: Chapter 3; Table 3.1; Page No. 5; CAC/MH 1-240c**

**PREAMBLE:** Historically, electricity consumption has been associated with economic activity, as measured by real Gross Domestic Product (GDP). A growing economy is associated with increased electricity consumption while economic downturns have a tendency to reduce or stall the growth of consumption. While the correlation between GDP and electricity consumption has been moderated by shifts away from manufactured goods and more towards services, the decrease in North American electricity consumption during the 2008–2009 economic recession demonstrates that overall economic conditions still have a significant impact on electricity consumption."

In Table 3.1, Manitoba Hydro provides the NERC forecast of annual Total Demand Growth Across Regions. In Figure 3.4, Comparison of Forecast GDP, Manitoba Hydro suggests that GDP growth in the U.S. will outstrip GDP growth in Manitoba. At page 6 of the September 5, 2013 PowerPoint document Manitoba Hydro Electric Load Forecast, the corporation summarizes its findings related growth in residential load. September 5, 2013 PowerPoint document Manitoba Hydro Electric Load Forecast.

**QUESTION:**

Please provide any comparable 10 year analysis for the MISO region and MRO-Manitoba Hydro.

**RESPONSE:**

Another comparable load growth analysis for the MISO region is provided by MISO in its annual MISO Transmission Expansion Plan (MTEP). As noted in Chapter 6, Section 6.2.1, Expectation of Gradual Load Growth, "MISO has estimated a compound annual load-growth rate of 0.95% over the next 10 years in its 2012 Transmission Expansion Plan."

Since Manitoba Hydro filed its submission in August 2013, MISO released its 2013 MTEP, which indicates an average annual growth rate of 0.75% for demand and a 0.81% growth rate for energy for the MISO region to 2028 under its Business as Usual (BAU) scenario.

**REFERENCE: Chapter 1; Section 1.4.1.2; 1.4.1.3; Page No. 14, 15; CAC/MH I-249**

**PREAMBLE:** According to the filing, a significant strength of the proposed project is the consultation with the KCN partners and the application of Aboriginal Traditional Knowledge.

It is well established that the KCN partners, who reside closest to the proposed development site, will directly experience many of the positive and negative impacts of the development.

**QUESTION:**

Please confirm that neither ATK nor direct input from KCN partners were taken into consideration in the development of the MABCA framework.

**RESPONSE:**

The MA-BCA evaluation framework was structured following principles of benefit-cost analysis. MA-BCA has compared the trade-offs of different development plans, some of which include Keeyask, from the perspective of Manitobans generally and not from the perspective of any particular community of Manitobans.

As described in the NFAT submission, the KCN partners have been participating in a collaborative process for the planning and licensing of the Keeyask Generating Station specifically. The KCN partners contributed their ATK, including their worldview, to the planning and environmental assessment of the project. Information from the assessment contributed to an understanding of the environmental and socio-economic effects of the Keeyask Project used in the MA-BCA.

## REFERENCE: Question CAC/MH I-250

## QUESTION:

Please confirm that, aside from the information found specifically within Chapter 13, Dr. Shaffer was not otherwise advised of circumstances in which the views of the KCN differed from those of Manitoba Hydro.

## RESPONSE:

As set out in the response to CAC/MH I-250, Dr. Shaffer relied on the information provided and referenced in Chapter 13.

**REFERENCE: Question CAC/MH I-162a**

**PREAMBLE:** Section 32 Part (1) of SARA states that:

"no person shall kill, harm, harass, capture or take an individual of a wildlife species that is listed as an extirpated species, an endangered species or a threatened species".

Section 33 of SARA states that:

"no person shall damage or destroy the residence of one or more individuals of a wildlife species that is listed as an endangered species or a threatened species, or that is listed as an extirpated species if a recovery strategy has recommended the reintroduction of the species into the wild in Canada".

Section 72 of SARA states that:

"The agreement may be entered into, or the permit issued, only if the competent minister is of the opinion that (a) the activity is scientific research relating to the conservation of the species and conducted by qualified persons; (b) the activity benefits the species or is required to enhance its chance of survival in the wild; or affecting the species is incidental to the carrying out of the activity."

Section 73(3) states that:

"The agreement may be entered into, or the permit issued, only if the competent minister is of the opinion that (a) all reasonable alternatives to the activity that would reduce the impact on the species have been considered and the best solution has been adopted; (b) all feasible measures will be taken to minimize the impact of the activity on the species or its critical habitat or the residences of its individuals; and the activity will not jeopardize the survival or recovery of the species."

In its response to 162a, Manitoba Hydro states that "If Lake Sturgeon were to be listed as endangered Manitoba Hydro would apply for permits to construct and operate the Project."

**QUESTION:**

Taking into account the strong language used within SARA, does Manitoba Hydro have a plan if Lake Sturgeon are listed as endangered and Manitoba Hydro is subsequently refused permits to construct and operate the project? If yes, what is this plan?

**RESPONSE:**

Manitoba Hydro notes that in the case of Keeyask, it is considered highly unlikely that a listing decision will be made prior to the planned start of construction in June 2014. Furthermore, Manitoba Hydro has judged the likelihood of Lake Sturgeon being listed under the *SARA* at this time to be low. (Please refer to the response to PUB/MH I-196a for further information.) Manitoba Hydro believes that the Lake Sturgeon stewardship activities being currently undertaken could result in a reassessment of its status by COSEWIC and the potential for listing under SARA at any time is thus reduced. Regardless of whether the Lake Sturgeon are listed under the *SARA*, the federal Department of Fisheries and Oceans (DFO) will continue to manage the species under the *Fisheries Act*, and has indicated its intent to apply strict standards to that management, because of the at risk status of the species.

However, if Lake Sturgeon are listed as endangered under the *SARA*, it is recognized there will be an additional prohibition on causing harm to the species, above and beyond that already prohibited by the *Fisheries Act* and if harm to the species cannot be avoided, then permits will be needed to ensure continued compliance with the *SARA*, at least over the short term. Over the long term, activities can also be authorized in recovery strategies or action plans which the DFO must develop once the species is listed.

Manitoba Hydro is aware that permits under the *SARA* for incidental harm to listed endangered or threatened species have not been commonly issued for industrial activities. To some extent this has been because the implementation of the *SARA* has been in its early stages and the regulatory and policy regime required for permit applications has been under development.

With the recent implementation of the *Permits Authorizing and Activities Affecting Listed Wildlife Species Regulations* (SOR/2013-140), and the development of policy by Environment Canada and the DFO, the interpretation of the s. 73 permit conditions is better understood, it is evident that such permits can, and have been, obtained.

Manitoba Hydro is committed to conserving and enhancing Lake Sturgeon populations in Manitoba, and is engaged in extensive stewardship efforts as due diligence to ensure that its operations and developments do not jeopardize the sustainability of Lake Sturgeon populations. These include an internal formal Lake Sturgeon Stewardship and Enhancement Program (LSSEP), and a *Memorandum of Understanding Respecting Lake Sturgeon* with Manitoba Conservation and Water Stewardship (MCWS), to coordinate its activities with the Manitoba Lake Sturgeon Management Strategy. For more information on the LSSEP please refer to Appendix 2.1 Lake Sturgeon - Mitigation and Enhancement, of the submission.

Manitoba Hydro has also proactively entered into negotiations on a Memorandum of Understanding with the DFO and MCWS, that will set out the process for developing a Conservation Agreement under the *SARA*. A Conservation Agreement on Lake Sturgeon will set out binding stewardship and enhancement activities, timelines, and responsibilities of the Parties.

Conserving and enhancing Lake Sturgeon populations has been a high priority in the planning of the Keeyask Generation Project, which has been designed to avoid and minimize impacts on the species. Measures include turbines with high fish survival rates, barriers to prevent larger fish from passing though the powerhouse, and selective transportation of fish upstream. In addition, new habitat will be constructed to ensure that habitat for all life stages will be available above and below the generating station, and a new stocking program to enhance Lake Sturgeon populations in the areas directly affected by Keeyask, as well as the broader region, will be implemented. Strict measures will also be implemented during the construction phase to ensure protection of the species. Manitoba Hydro will use an adaptive management strategy, including comprehensive monitoring and adjustment of mitigation measures as required to ensure continued protection of the species once the Project is in operation.

Manitoba Hydro is confident that the proposed measures for the Keeyask Generation Project, which are summarized in Appendix 2.1 Lake Sturgeon – Mitigation and Enhancement, will minimize the potential for any harm to the individual Lake Sturgeon. If harm to the species can be avoided completely, then there will be no need for permits under the *SARA*. However, if there remains a potential for harm in either the construction or operational phase of the Keeyask Generation Project, permits under either s. 73 or s. 74 of the *SARA* will need to be secured, at least in the short term until such time as recovery strategies or action plans are developed by the DFO.

Manitoba Hydro is also confident the Keeyask Generation Project design, in conjunction with the enhancement of Lake Sturgeon habitat, stocking, and further activities to be implemented through the LSSEP and cooperative stewardship with our Project partners, will meet the conditions of s. 73 of the *SARA*, and therefore permits will be able to be secured. Manitoba Hydro will continue to work with the DFO throughout the planning process to determine what, if any, additional steps need to be taken to meet the *SARA* permit requirements.

A principal purpose of the Conservation Agreement currently in negotiation is to establish activities to be carried out to conserve the Lake Sturgeon, and to enhance its potential for recovery. In this respect, while the Conservation Agreement is not itself a permit under the *SARA*, the binding commitments under it can be relied upon, along with other project specific requirements, to facilitate compliance with the conditions for *SARA* permits. The negotiations towards a Conservation Agreement are therefore expected to reduce the risk that a permit under the *SARA* would be denied.

In essence, while Manitoba Hydro recognizes that there is no guarantee that *SARA* permits, if needed, will be secured, it is confident that the actions it is undertaking now, both in the design of the Keeyask Generation Project, and its work to enhance and recover the species, make the likelihood of a permit under the *SARA* being denied, low.

Manitoba Hydro's response to the unlikely situation that permits under the *SARA* could not be secured prior to the start of construction, would be to delay the project and make further efforts to work with the DFO to determine what additional measures could be undertaken to secure a permit for construction. If a construction permit was refused outright then Manitoba Hydro would exercise the optionality built into the development plan and proceed with another form of generation.

Manitoba Hydro believes the extensive mitigation and enhancement measures being developed in the pre-construction phase, and the ongoing commitment by Manitoba Hydro, in conjunction with its project partners and the DFO and MCWS, to the stewardship of Lake Sturgeon on the Nelson River, result in little risk that an operating permit would not be granted if Lake Sturgeon were listed after project construction has been completed.

Furthermore, once the Lake Sturgeon are listed, it is likely the recovery strategies and action plans to be developed may establish specific hydro related activities which are authorized on the Nelson River which will make long term operational permits under the *SARA* unnecessary.

**REFERENCE: CAC/MH I-162a**

**PREAMBLE:** In its response to 162a, Manitoba Hydro states that "Given the precautionary approach of the DFO on Lake Sturgeon protection, which would be incorporated into the conditions of a Fisheries Act authorization for the Project that Manitoba Hydro would be required to satisfy, it is expected that any cost and timing delays that could result from a potential Lake Sturgeon listing and permitting requirements would not be sufficient to negate the positive conclusions regarding Pathways 3, 4 or 5."

**QUESTION:**

Please explain how Manitoba Hydro came to the conclusion that "any cost and timing delays that could result from a potential Lake Sturgeon listing and permitting requirements would not be sufficient to negate the positive conclusions regarding Pathways 3, 4 or 5." Please provide any analysis that was used in coming to this conclusion.

**RESPONSE:**

Manitoba Hydro has examined a one year delay to Keeyask and Conawapa in Chapter 10 of the NFAT submission. It is expected that this would provide sufficient time to satisfy any permitting requirements that could arise in the event of a decision to list Lake Sturgeon under the *Species At Risk Act (SARA)*. The DFO has indicated, that while Lake Sturgeon is not listed under the *SARA*, its “at risk” status is a key factor in its consideration of conditions for authorizations to be issued under the *Fisheries Act*. For this reason, Manitoba Hydro considers it is unlikely any additional requirements to meet the conditions for permits under the *SARA* would cause more than a one year delay .

This is also consistent with the terms of the export agreements with Minnesota Power and Wisconsin Public Service, which allow for a delay of up to two years for regulatory reasons. The analysis shows that a one year delay in the in-service date of both Keeyask and Conawapa would result in a $97 million NPV cost in the reference scenario, which is not sufficient to negate the positive conclusions regarding Pathways 3, 4 or 5. Please refer to the response to CAC/MH I-231b for further information.