



The Public Utilities Board

Report on the **Needs For and Alternatives To (NFAT)**

Review of Manitoba Hydro's
Preferred Development Plan

June 2014

[THIS PAGE INTENTIONALLY LEFT BLANK]

MESSAGE FROM THE PANEL

Manitobans have benefited from many decades of inexpensive electricity, in large part because of earlier decisions to develop the province's rich hydraulic resources. Manitobans will continue to be highly reliant on these resources for their power generation, and this Report addresses incremental additions to a hydro-dominant system.

At the same time, Manitoba's energy future is uncertain. Wind, solar and energy efficiency technologies, flattening load growth, volatile natural gas prices, climate change and the resulting impacts on water flows, and regulatory changes including the potential for carbon taxes are all creating upheaval in North American energy markets.

Faced with these uncertainties, and in light of the short time frame for the Panel to conduct the review, it would have been tempting to recommend deferring decisions. The Panel took a different route. This Report frames a new energy future for Manitoba.

The Panel expresses its appreciation and gratitude to all participants in the NFAT Review, especially the Public Utilities Board's Staff and Advisors. Any errors and omissions in this Report are solely the responsibility of the Panel.

Respectfully submitted,

Winnipeg, June 20, 2014



Régis Gosselin, Chairperson



Richard Bel



Hugh Grant



Marilyn Kapitany



Larry Soldier

AUSSI DISPONIBLE EN FRANÇAIS

[THIS PAGE INENTIONALLY LEFT BLANK]

TABLE OF CONTENTS

Executive Summary	18
A. Mandate	18
B. Key Panel Recommendations	18
C. The NFAT Review Process	19
D. The Need for New Resources	20
E. Manitoba Hydro's Load Forecast	21
F. Demand Side Management (DSM)	21
G. Defining Manitoba Hydro's Preferred Development Plan	23
H. Pathways vs. Projects	24
I. Alternatives Evaluated	24
J. Economic Comparison of Alternatives	27
K. Financial Evaluation and Rate Impacts	28
L. Economic Risk Factors	29
i. Capital Cost Uncertainty.....	29
ii. Export Revenue Projections.....	30
M. Socio-Economic Evaluation.....	31
N. Macro Environmental Evaluation.....	32
O. Integrated Resource Planning.....	33
P. Panel Conclusions and Recommendations.....	34
1.0.0 The Needs For and Alternatives To Review.....	38
1.1.0 Background.....	38
1.2.0 The Nature and Role of the Public Utilities Board	38
1.3.0 Formation of the Needs For and Alternatives To (NFAT) Review	39
1.3.1. Order in Council and Terms of Reference.....	39
1.3.2. Matters Not Within the Scope of the Review	39
1.3.3. Conduct of the NFAT Review	40
1.3.4. Report to Government.....	40
1.4.0 Review Parties and Participants.....	40
1.4.1. The PUB NFAT Review Panel.....	40

1.4.2.	Manitoba Hydro	41
1.4.3.	Intervenors	41
1.4.4.	Independent Expert Consultants	42
1.4.5.	Presenters	44
1.5.0	Review Process and Hearing	44
1.5.1.	The Hearing	44
1.5.2.	Filings and Records of the Hearing	45
1.5.3.	Commercially Sensitive Information	45
1.5.4.	Weighing of Evidence	46
2.0.0	Manitoba Hydro's Preferred Development Plan	47
2.1.0	Preferred Development Plan Components	47
2.1.1.	The Keeyask Project	47
2.1.2.	The Conawapa Project	48
2.1.3.	North-South Transmission System Upgrade Project	48
2.1.4.	Manitoba-Minnesota Transmission Project	49
2.1.5.	Great Northern Transmission Line	49
2.2.0	The Preferred Development Plan and its Alternatives	50
2.2.1.	Pathways	50
2.2.2.	Developments During the NFAT Review	53
3.0.0	Alignment with Applicable Legislative and Policy Documents	54
3.1.0	Introduction	54
3.2.0	The Manitoba Hydro Act	54
3.3.0	Manitoba's Clean Energy Strategy	55
3.4.0	The Climate Change and Emissions Reductions Act	57
3.5.0	Principles of Sustainable Development (as outlined in The Sustainable Development Act)	57
3.6.0	Conclusions of the Panel	58
4.0.0	Domestic Need and Load Forecast	59
4.1.0	Introduction	59

4.2.0	The Components of Manitoba's Electricity Demand.....	59
4.2.1.	Energy and Capacity Demands.....	59
4.2.2.	Main Customer Components.....	61
4.3.0	Load Forecasts	63
4.3.1.	Load Forecasting Methodology	63
4.4.0	Need for New Resources	66
4.5.0	Transformative Change in Load Demand.....	68
4.5.1.	Structural Changes to Forecast Fundamentals	68
4.5.2.	Impact of Grid Parity.....	69
4.6.0	Reliability and Security of Manitoba's Electricity Supply	70
4.7.0	Conclusions of the Panel.....	71
5.0.0	Demand Side Management (DSM)	73
5.1.0	Introduction	73
5.2.0	Manitoba Hydro's Power Smart Programs and DSM Proposal	74
5.2.1.	Manitoba Hydro's Power Smart Programs	74
5.2.2.	Revised Manitoba Hydro DSM Proposals (March 2014)	75
5.3.0	The Impact of New DSM on Load Growth.....	77
5.4.0	The Value Proposition of DSM	80
5.4.1.	Role of DSM in Resource Planning.....	81
5.4.2.	Value of DSM to Ratepayers: Savings Potential	83
5.4.3.	Value to Lower Income Customers	85
5.4.4.	The Curtailable Rate Program (CRP).....	86
5.4.5.	DSM and Fuel Switching	87
5.4.6.	DSM Employment Potential	88
5.4.7.	Environmental Benefits of DSM.....	89
5.4.8.	Implementing a Successful DSM Program.....	89
5.5.0	Conclusions of the Panel.....	91
6.0.0	Exports Markets and Contracts.....	95
6.1.0	Introduction	95

6.2.0	Background and Context.....	95
6.2.1.	History of Manitoba Hydro's Exports	95
6.2.2.	Export Sales, Services and Products	96
6.2.3.	Surplus By Design.....	97
6.3.0	Export Markets	98
6.3.1.	Canadian Export Markets.....	98
6.3.2.	United States/MISO.....	99
6.4.0	Export Market Forecast.....	99
6.4.1.	Introduction	99
6.4.2.	The Nature of the MISO Market: Influences and Determinants.....	100
6.4.3.	Energy Price Forecasts	105
6.4.4.	"Window of Opportunity"	107
6.4.5.	Export Volume Assumptions	108
6.5.0	Export Prices, Revenues Forecast and Contracts.....	109
6.5.1.	Existing and Future Export Contracts.....	109
6.5.2.	Impact of Exports on Selected Plans.....	110
6.5.3.	Assessing the Contract Terms and Conditions	110
6.5.4.	Export Revenue Forecasts.....	112
6.6.0	Conclusions of the Panel.....	114
7.0.0	Cost of New Generation and Transmission.....	118
7.1.0	Introduction	118
7.2.0	Alternative Plans and New Generation Requirements	118
7.3.0	Hydropower Projects: Keeyask and Conawapa	119
7.3.1.	Overview of the Keeyask and Conawapa Projects.....	119
7.3.2.	Construction Costs of Keeyask and Conawapa Projects	120
7.3.3.	Construction Contingencies and Reserves	121
7.3.4.	Keeyask Construction Contract.....	122
7.4.0	Transmission.....	123
7.4.1.	Overview of Transmission Components.....	123
7.4.2.	Proposed Transmission Connections.....	124

7.4.3.	The Role and Value of Transmission Export and Import Capacity	126
7.5.0	Manitoba Hydro's Proposed Generation Alternatives.....	127
7.5.1.	Thermal Gas Generation.....	128
7.5.2.	Solar Power Generation	129
7.5.3.	Wind Power	130
7.6.0	Conclusions of the Panel.....	132
8.0.0	Economic Evaluation.....	135
8.1.0	Introduction	135
8.1.1.	Types of Evaluations	135
8.1.2.	Metrics.....	135
8.2.0	Manitoba Hydro's Economic Evaluation.....	137
8.2.1.	Economic Evaluation Parameters	137
8.2.2.	Manitoba Hydro's Initial Evaluation Results	138
8.2.3.	Updated Evaluation During NFAT Review Hearing	140
8.3.0	La Capra's Alternative Plans	145
8.4.0	Uncertainty Analysis.....	146
8.5.0	Specific Risk factors	153
8.6.0	Selected Issues Relating to Manitoba Hydro's Analytical Approach	153
8.6.1.	Treatment of Cash Transfers to the Province.....	153
8.6.2.	Embedded Return on Equity	154
8.6.3.	How Determinative is the NPV Analysis?	156
8.6.4.	Timeframe of the Analysis.....	157
8.6.5.	Treatment of Sunk Costs.....	158
8.6.6.	Discount Rate.....	159
8.7.0	Conclusions of the Panel.....	159
9.0.0	The Rate Impacts of the Preferred and Alternative Development Plans	162
9.1.0	Introduction	162
9.2.0	Manitoba Hydro's Current Revenue Base.....	162
9.3.0	Manitoba Hydro's Financial Targets.....	164

9.3.1.	Debt-to-Equity Ratio	164
9.3.2.	Interest Coverage Ratio	165
9.3.3.	Capital Coverage Ratio	166
9.4.0	Manitoba Hydro's NFAT Financial Evaluation	167
9.5.0	Impact of Development Plans on Electricity Rates	170
9.6.0	Impact of Demand Side Management Programs on Rates	172
9.7.0	Impact of Sunk Costs on the Projected Rate Increases	172
9.8.0	Impact of Bipole III on Rates	174
9.9.0	Export Revenue Forecasts	174
9.10.0	Other Metrics for Examining Rates and Revenues	176
9.10.1.	Net Present Value Analysis	176
9.10.2.	Impact of Rate Increases on Ratepayers	177
9.10.3.	Present Value of Customers' Revenues	177
9.10.4.	Plan 5 (K19/Gas/750 MW) Rate Pathway vs. Plan 14 (Preferred Development Plan)	181
9.10.5.	Intergenerational Impacts	181
9.11.0	Bill Impacts	183
9.11.1.	Impact on Lower Income and Vulnerable Consumers	184
9.11.2.	Impact on Northern and Aboriginal Customers	185
9.11.3.	Impact on Commercial and Industrial Customers	187
9.12.0	Manitoba Hydro's Alternative Rate Methodologies	187
9.13.0	Mitigating the Impact of Rate Increases	189
9.14.0	Conclusions of the Panel	191
10.0.0	Risk and Uncertainty	192
10.1.0	Introduction	192
10.2.0	Identification and Ranking of Risk Factors	193
10.2.1.	Energy Prices	194
10.2.2.	Assumptions for a Recovery of U.S. Demand to Pre-2008 Levels	195
10.2.3.	The Future Price of Natural Gas	197
10.2.4.	The Development of a Carbon Price Regime in the U.S.	197
10.2.5.	Assumptions Regarding Coal Retirements	199

10.2.6.	Discount Rate & Interest Rates	199
10.2.7.	Load Forecast and Demand Side Management.....	201
10.2.8.	Construction Costs	201
10.2.9.	Climate Change and Drought.....	202
10.2.10.	Drought Impacts and Mitigation.....	204
10.2.11.	U.S. Transmission Interconnection Approval	205
10.2.12.	Financial Impact to the Province of Manitoba.....	205
10.2.13.	Risk Impact on Ratepayers Compared to Risk Impacts to the Province	205
10.3.0	Conclusions.....	206
11.0.0	Socio-Economic Impacts.....	209
11.1.0	Introduction and Background	209
11.2.0	Qualitative Assessment of Resource Technology Options.....	210
11.2.1.	Manitoba Hydro's Screening of Resource Technology Options	210
11.2.2.	Considering the Employment Benefits of Other Options: Wind and Demand Side Management.....	211
11.3.0	The Socio-Economic Impacts of the Preferred Development Plan.....	212
11.3.1.	Manitoba Economic Impacts	215
11.3.2.	Employment Benefits	216
11.4.0	The Keeyask Project and Northern Aboriginal Communities.....	218
11.4.1.	Joint Keeyask Development Partnership.....	218
11.4.2.	Employment and Training	219
11.4.3.	Business and Economic Impacts.....	220
11.4.4.	Impacts on Communities, Culture, and Health	222
11.5.0	Multiple Account Benefit-Cost Analysis	223
11.6.0	Government of Manitoba Benefits.....	225
11.7.0	Conclusions of the Panel.....	226
12.0.0	Macro Environmental Considerations	229
12.1.0	Introduction	229
12.2.0	Background and Context.....	229

12.2.1.	Defining the Term “Macro Environmental”	229
12.2.2.	The Environmental Regulatory Process	229
12.3.0	Manitoba Hydro’s Environmental Assessment Approach.....	231
12.3.1.	Environment Account of Multiple Account Benefit/Cost Analysis	231
12.3.2.	Matrix Comparison of Different Technologies	231
12.4.0	Climate Change: Greenhouse Gases and Air Pollutants	232
12.4.1.	Introduction	232
12.4.2.	Assessment by Resource Option	232
12.5.0	Comparing Environmental Effects for Competing Technologies	235
12.5.1.	Introduction	235
12.5.2.	Hydropower Generation	235
12.5.3.	Natural Gas Thermal Generation	236
12.5.4.	Wind Power	237
12.5.5.	Solar Photovoltaic Power	237
12.5.6.	Demand Side Management.....	237
12.6.0	Valued Ecosystem Components (VECs).....	237
12.6.1.	Introduction and Scope	237
12.6.2.	Lake Sturgeon.....	238
12.6.3.	Caribou.....	239
12.6.4.	Mercury	240
12.7.0	Adverse Effects Agreements.....	240
12.8.0	Need for Regional Cumulative Environmental Assessment	240
12.9.0	Conclusions of the Panel.....	241
13.0.0	The Commercial Perspective	243
13.1.0	Introduction	243
13.2.0	The “Positional View”	243
13.3.0	The Situation Today	245
13.4.0	The Parameters of the Commercial Perspective.....	246
13.5.0	Conclusions of the Panel.....	247

14.0.0	Recommendations	249
APPENDIX 1	Order in Council and Terms of Reference.....	254
APPENDIX 2	NFAT Panel Member Biographies.....	266
APPENDIX 3	Chronology of Events	268
APPENDIX 4	Independent Expert Consultant Scope of Work	272
APPENDIX 5	Interveners	273
APPENDIX 6	Summary of Intervener Closing Submissions.....	275
APPENDIX 7	Summary of Public Presentations	284
APPENDIX 8	Appearances	295
APPENDIX 9	Glossary of Terms.....	299

LIST OF TABLES

Table 1	List of Independent Expert Consultants	43
Table 2	Description of Manitoba Hydro's Development Plans	51
Table 3	Load Forecast Adjustments to Manitoba Hydro's 2014 Load Forecast	61
Table 4	Need for New Resources Under Different Planning Assumptions.....	67
Table 5	Export Price Forecast Comparison: No Carbon/Low Carbon (US\$/MWh) ..	107
Table 6	List of Current and Future Manitoba Hydro Export Contracts.....	109
Table 7	Exports as % of Total Revenues : 2013 vs. Updated Plans	110
Table 8	Manitoba Hydro's Gross Export Revenues	112
Table 9	List of New Resource Components by Development Plan.....	119
Table 10	Keeyask and Conawapa Construction Budget Updates, 2009-2014.....	121
Table 11	Manitoba Hydro Interconnection Limit and Capacities	124
Table 12	Comparison of Installed Capital Cost and Per Unit Costs Based on Utility Scale Generation in Manitoba	128
Table 13	Incremental Net Present Values of Alternative Plans Compared to All Gas Plan under Ref-Ref-Ref Assumptions, With In-Service Dates for Subsequent New Generation	143
Table 14	Summary – CPVs as compared to All Gas Plan at the End of Various Periods, Break-Even Year, 78 year IRR and 78 Year CPV of Total Capital (\$millions in 2014 Present Value Dollars)	145
Table 15	Manitoba Hydro's Initial Incremental Economics – All Scenarios	148
Table 16	Manitoba Hydro Initial Expected Value Calculation.....	148
Table 17	March 10, 2014 Updated Expected Values	150
Table 18	March 10, 2014 Updated Probabilistic Quilt	151
Table 19	Evaluated Plans: Financial Analysis Based on 2012 Planning Assumptions	168
Table 20	Projected Even Annual and Cumulative Rate Increases by Development Plan, 2013 Assumptions/DSM 2/Reference & High Capital Costs (Main Submission Rate Methodology).....	171
Table 21	Rate Increases by Development Plan under Reference Conditions With and Without Sunk Costs.....	173
Table 22	Projected Domestic and Extra-Province Revenues, DSM Level 2 + Pipeline Load \$ million	175
Table 23	Exports as % of Total Revenues: 2013 vs. Updated Plans	176

Table 24	Morrison Park's Calculation of Total Cost to Ratepayers at 3.8% Maximum Annual Rate Changes	179
Table 25	Morrison Park's Calculation of Ratepayer Cost Impacts of 2014 Update of Planning Assumptions.....	180
Table 26	Morrison Park's Calculation of Ratepayer Costs for Alternative Periods.....	182
Table 27	La Capra Associates - Projected Monthly Residential Electricity Bill (Non-Electric Heat, 750 kWh/month).....	184
Table 28	Dr. Higgin (CAC) Calculation - Bill Increases for Electric Heat, 2013 to 2023	185
Table 29	Cumulative Rate Increases at DSM Level 2, Using Alternative Methodologies and Reference Capital Cost	189
Table 30	Historical Droughts Experienced in Manitoba.....	203
Table 31	Incremental Benefit to Ratepayers and Government After 30 Years (Net Present Value Basis - \$ millions).....	206
Table 32	Socioeconomic Screening of Generation Technologies.....	211
Table 33	Economic Impact Analysis of the Preferred Development Plan Based on the Manitoba Bureau of Statistics Model.....	214
Table 34	Manitoba Economic Impacts of the Keeyask Project and 750 MW Transmission Interconnection	215
Table 35	Anticipated Gross Wages for Construction and O&M	217
Table 36	Anticipated Employment Net Benefits for Project Construction and O&M...	218
Table 37	Keeyask Project Summary of Socio-Economic Benefits for Northern Manitobans.....	220
Table 38	Estimated Benefits to the Keeyask Cree Nations.....	221
Table 39	Manitoba Hydro Multiple Account Benefit-Cost Analysis Summary	224
Table 40	Morrison Park – Average Present Value of Revenue to the Province of Manitoba	225
Table 41	Cumulative Greenhouse Gas Emissions and Cumulative Greenhouse Gas Displacement Potential of Alternative Development Plans.....	234

LIST OF FIGURES

Figure 1	Pathways Identified by Manitoba Hydro	52
Figure 2	Manitoba Hydro Energy Supply and Demand (K19/C26/750MW – Pipeline Load)	68
Figure 3	Manitoba Hydro 2014 Power Smart Plan vs. DSM Level 2 Savings	77
Figure 4	Incremental Savings - Manitoba Hydro DSM Levels 2 & 3 vs. Dunsky Scenarios	78
Figure 5	DSM Scenarios' Impact on Manitoba Hydro Load Forecast.....	79
Figure 6	Manitoba Hydro's Gross Export Revenues and Volumes (1967-2013)	96
Figure 7	Energy Information Agency Natural Gas Price Forecasts (2013 Energy Outlook, real US\$/mmBtu at Henry Hub)	101
Figure 8	Potomac Economics Export Price Forecasts	104
Figure 9	Potomac Economics Reference Case Energy Prices	105
Figure 10	Transmission Engineering, Procurement and Construction Timetable, 2014-2020	124
Figure 11	Results of Manitoba Hydro's Initial Incremental NPV Evaluation	139
Figure 12	La Capra Associates "Waterfall" Chart Showing Impact of Updated Information on the Economics of the Preferred Development Plan.....	141
Figure 13	La Capra Associates Chart Showing the 78-Year Incremental NPV of Preferred Development Plan Components.....	144
Figure 14	Probability Weightings for Energy Prices, Discount Rate and Capital Cost	147
Figure 15	March 10, 2014 Updated Probability Weightings for Energy Prices, Discount Rate, and Capital Costs	149
Figure 16	Manitoba Hydro Embedded Return on Equity	154
Figure 17	Manitoba Hydro Exhibit #171 Excluding Embedded Equity	156
Figure 18	Electricity Revenue Sources, 2003/04 to 2012/13.....	163
Figure 19	Manitoba Hydro's Debt-to-Equity Ratio, 2008 to 2033	165
Figure 20	Interest Coverage Ratio, 2008 to 2033	166
Figure 21	Capital Coverage Ratio, 2008 to 2033	167
Figure 22	Tornado Diagram Showing Sensitivity of the Preferred Development Plan to Different Risk Factors.....	193
Figure 23	Brattle Group Summary of Current and Historic Carbon Price Assumptions	198
Figure 24	Annual Employment Estimate for Project Construction.....	216

Figure 25 Comparison of Life Cycle Greenhouse Gas Emissions for Different Sources of Electricity.....	233
-------------------------------------------------------------------------------------------------------	-----

Executive Summary

A. Mandate

By way of an Order in Council, on April 17, 2013, the Government of Manitoba asked a Panel of the Public Utilities Board of Manitoba (PUB) to conduct a review into the Needs For and Alternatives To (NFAT Review) Manitoba Hydro's Preferred Development Plan, and issue a Report to the Minister responsible for the administration of *The Public Utilities Board Act* by June 20, 2014. The Terms of Reference issued for the NFAT Review require the Panel's report to address the needs for Manitoba Hydro's Preferred Development Plan and to provide an overall assessment as to whether or not the Plan is in the best long-term interest of the Province of Manitoba when compared to other options and alternatives.

Manitoba Hydro's Preferred Development Plan consists of the following components:

- The 695 megawatt (MW) Keeyask Project (\$6.5 billion), with a planned in-service date of 2019;
- The 1,485 MW Conawapa Project (\$10.7 billion), with a planned in-service date of 2026;
- The North-South Transmission Upgrade Project (approximately \$500 million), with an in-service date to coincide with the installation of the last turbine unit of Conawapa; and
- The 750 MW U.S. Transmission Interconnection Project terminating near Duluth, Minnesota (approximately \$1 billion).

B. Key Panel Recommendations

As a result of its review, the Panel rejects Manitoba Hydro's Preferred Development Plan, as well as Manitoba Hydro's suggestion to consider pathways that map out a 78-year future, as the Panel sees Manitoba Hydro's long-term future projections as highly speculative and too uncertain.

The Panel recommends to the Government of Manitoba that:

- Spending on the Conawapa Project and the North-South Transmission Upgrade Project be discontinued immediately and the projects terminated;
- The Keeyask Project proceed with an in-service date of 2019;
- The 750 MW U.S. Transmission Interconnection Project proceed;

- Manitoba Hydro be divested of Demand Side Management (DSM) responsibilities and the Government of Manitoba establish an independent arm's length entity to deliver government-mandated DSM targets; and
- The Government of Manitoba not approve any further generation and transmission projects, or approve the commencement of spending on such projects, unless such projects have been examined through a comprehensive and regularly occurring integrated resource planning process.

In reaching its recommendation with respect to the Keeyask Project, the Panel concluded that natural gas generation does not present an acceptable alternative, as it is less economic than hydroelectric generation and relies on burning fossil fuel. Furthermore, any short-term capital cost advantages are offset by significant ongoing operating cost risk, primarily fuel costs. Similarly, wind generation does not currently represent a preferred alternative to Keeyask based on economics.

The Panel's full conclusions and recommendations are set out in Chapter 14 and described at the end of this Executive Summary.

C. The NFAT Review Process

The NFAT Review was governed by the NFAT Terms of Reference as well as the PUB's Rules of Practice and Procedure. As permitted by the Rules of Practice and Procedure, the Panel granted Intervener status to five organizations, namely the Consumers' Association of Canada (Manitoba) Inc. (CAC), the Green Action Centre (GAC), the Manitoba Industrial Power Users Group (MIPUG), the Manitoba Métis Federation (MMF) and Manitoba Keewatinowi Okimakanak Inc. (MKO).

The NFAT Terms of Reference also permitted the Panel to appoint Independent Expert Consultants (IECs) in different subject areas to examine the Preferred Development Plan, file expert reports on the record, and testify in the NFAT Review. The Panel appointed eight IECs to provide evidence at the hearing.

Manitoba Hydro filed its written NFAT Business Case on August 16, 2013 and was subject to two rounds of written Information Requests, which were in part answered through direct discussion between the NFAT Review participants and Manitoba Hydro. Evidence from Interveners and IECs was subject to one round of Information Requests.

The oral evidentiary portion of the NFAT Review started on March 3, 2014, and ended with Manitoba Hydro's closing submissions on May 26, 2014. Overall, the Panel heard 43 days of evidence.

In addition to hearing evidence, the Panel also heard from numerous Presenters, both in Winnipeg and in Thompson, Manitoba. Their Presentations are summarized in Appendix 6.

D. The Need for New Resources

The need for new electricity resources in Manitoba is determined by three things: the level of demand growth in the province projected through load forecasting, existing contractual export obligations, and any reductions in this anticipated demand that can be achieved through DSM initiatives.

Electrical demand is made up of two components: energy, which is the amount of electricity used over a period of time measured in gigawatt-hours (GWh); and capacity, which is the demand for energy at any given point in time measured in megawatts (MW).

Because Manitoba Hydro relies primarily on hydroelectricity, it is subject to water flow variations, which translate into variations in the amount of energy that can be produced in any given year. To meet Manitoba demand and firm export obligations, Manitoba Hydro relies only on dependable energy. Dependable energy is the amount of energy that can be produced during a year that mirrors the lowest-flow year in the last 100 years.

The year of need for new resources is the year in which Manitoba Hydro is first expected to experience a shortage of either dependable energy or capacity.

On its own accord and at the request of the Panel and Interveners, Manitoba Hydro analyzed the year of need based on several uncertainties:

- Whether a demand for 1,700 GWh as a result of oil and gas pipeline customers (pipeline load) would materialize;
- The magnitude of DSM initiatives and corresponding energy and capacity reductions; and
- The ability to serve export contracts, including the new Minnesota Power and Wisconsin Public Service contracts even if the Keeyask Project were deferred beyond 2019.

Based on these factors, the Panel concludes that new generation will likely be required no later than 2024. However, there are compelling economic, financial and commercial reasons to advance the Keeyask Project to 2019.

E. Manitoba Hydro's Load Forecast

Manitoba Hydro prepares a 20-year Load Forecast on an annual basis that projects demand in several customer classes, including Residential, General Service Commercial, General Service Industrial, and Top Consumers, the latter being the largest industrial consumers of electricity in the province. In its 2013 Load Forecast, Manitoba Hydro projects total demand for both energy and capacity to grow by 1.5% per year over the next 20 years. This represents a reduction from earlier planning assumptions.

Several parties criticized the methodologies used by Manitoba Hydro, but the Panel is satisfied that the load forecasting methodology is reasonable in the short term. The biggest short-term uncertainty is whether or not 1,700 GWh of new pipeline load will materialize in Manitoba. This could change the need date for new resources by a full seven years. There is sufficient evidence to assume that the pipeline load will materialize. Accordingly, it is prudent to plan for a need date on that basis.

The Panel has less confidence in Manitoba Hydro's Load Forecast over the long term, as the Load Forecast is unable to anticipate fundamental structural change that could greatly increase or decrease demand. An example of a structural change that could increase demand would be the widespread adoption of electric cars. An example of a structural change that could decrease demand would be alternative renewable technologies, such as domestic solar photovoltaic cells, which are rapidly becoming cost-competitive with traditional generation technologies. This concept is known as "grid parity."

Another long-term uncertainty is the effect of Demand Side Management (DSM), which has the potential to reduce the overall demand for electricity.

F. Demand Side Management (DSM)

DSM is the reduction of energy consumption through targeted energy efficiency and demand initiatives. DSM may also include the adoption of an alternative energy resource or technologies that may result in energy reductions (such as fuel switching to natural gas, domestic solar photovoltaic or heat pump technology). DSM is a powerful tool, as it can defer the need for new generation, and has the potential to be as economic, if not more economic, than new generation.

For consumers, DSM is attractive as it can lower their total consumption of energy, which mitigates the impact of higher rates. Consumers who fully avail themselves of DSM measures have the potential to lower their total energy bill even as rates increase.

Manitoba Hydro prepares a 3-year DSM plan, called Power Smart Plan, on an annual basis in consultation with the Province of Manitoba as required by *The Energy Savings Act*. Through DSM, Manitoba Hydro expects to offset 86% of the anticipated load growth to 2017.

In 2014, Manitoba Hydro also prepared a 15-year supplementary plan. In that plan, Manitoba Hydro expects to offset 66% of anticipated load growth to 2028/29, saving 1,136 MW of capacity and 3,978 GWh of dependable energy annually.

To place this into perspective, the capacity savings in the supplementary plan amount to more than 80% of the net system capacity addition from the proposed Conawapa Project. Similarly, the annual dependable energy savings from the Power Smart Plan exceed 85% of the dependable energy output from the proposed Conawapa Project. To achieve these electricity savings, Manitoba Hydro budgets \$822 million, which is less than 8% of the \$10.7 billion cost of building Conawapa.

While *The Energy Savings Act* requires consultation with respect to Manitoba Hydro, the Province of Manitoba does not currently set mandatory DSM targets.

Manitoba Hydro treats DSM as a reduction in load forecast demand, rather than as an alternative resource to meet demand projections. This approach was criticized by an independent expert and several Interveners. In their view, DSM should have the same status as generation sources, and be evaluated as such for planning purposes. The Panel shares that view.

Manitoba Hydro dramatically increased its projected DSM savings in the course of the NFAT Review. The Panel is uncertain that these projections can be achieved by Manitoba Hydro. However, this risk is mitigated by the Panel's recommendation to proceed with a 2019 in-service date for the Keeyask Project, which will provide sufficient energy and capacity to meet needs if projected savings do not fully materialize.

Manitoba Hydro's DSM targets appear to be overly aggressive in the short term, and overly conservative in the long term. While incremental DSM savings are projected to be significant in the first few years of the plan, they ultimately tail off. Other jurisdictions have reported that achieving sustainable annual incremental targets of 1.2-1.5% of forecast load is possible.

Manitoba Hydro, formerly a leader in DSM initiatives, has been surpassed by a number of other jurisdictions. Jurisdictions that are DSM leaders have separate DSM delivery entities with clear targets and accountability measures to achieve such targets. The Panel concludes that there is an inherent conflict in Manitoba Hydro being both a seller

of electricity and a purveyor of energy efficiency measures. A separate externally regulated entity is required to develop and implement energy efficiency measures and monitor their effectiveness. Such an entity should be subject to regular external audits to confirm DSM savings. Examples of similar arrangements exist in other North American jurisdictions.

The electricity savings delivered through an independent arm's-length entity would constitute an additional resource available to Manitoba Hydro to meet energy needs.

G. Defining Manitoba Hydro's Preferred Development Plan

Manitoba Hydro's Preferred Development Plan consists of the following:

- The 695 MW Keeyask Project (\$6.5 billion), with a planned in-service date of 2019;
- The 1,485 Conawapa Project (\$10.7 billion), with a planned in-service date of 2026;
- The North-South Transmission Upgrade Project (approximately \$500 million), with an in-service date to coincide with the installation of the last turbine unit of Conawapa; and
- The 750 MW U.S. Transmission Interconnection Project terminating near Duluth, Minnesota (approximately \$1 billion).

Manitoba Hydro predicated its Preferred Development Plan on a series of executed new power purchase agreements with U.S. counterparties, specifically:

- A 125 MW system power sale agreement with Northern States Power to run from 2021-2025;
- A 100 MW system power sale agreement with Wisconsin Public Service to run from 2021-2027;
- A 250 MW system power sale agreement with Minnesota Power to run from 2020-2035; and
- A 308 MW system power sale agreement with Wisconsin Public Service to run from 2027-2036.

The 308 MW Wisconsin Public Service contract is premised on the construction of the Conawapa Project. Although the export commitments under the contract can be fulfilled with Keeyask alone, this would require a waiver by both parties of the contractual requirement that Conawapa be built for the sale contract to proceed. There is reason to

believe that the contract will proceed if Manitoba Hydro can establish that sufficient firm energy will be available without Conawapa.

In addition to exports under contract, Manitoba Hydro also currently exports, and plans to continue to export, electricity into the Midcontinent Independent System Operator (MISO) market at prevailing spot market prices that vary on a day-ahead, real-time basis. Approximately 60% of Manitoba Hydro's projected export revenues are based on these opportunity sales. Manitoba Hydro's total energy exports into MISO represent less than two percent of the total energy in MISO, making Manitoba Hydro a price taker in that market.

Manitoba Hydro argued that a confluence of factors led by significant interest of U.S. counterparties in new imports from Manitoba Hydro and a strengthened interconnection created an opportunity to proceed with the Preferred Development Plan now. The Panel agrees with that argument as it relates to the Keeyask Project and the 750 MW Transmission Interconnection, but not as it relates to the Conawapa Project and the North-South Transmission Upgrade Project.

H. Pathways vs. Projects

In the course of the NFAT Review, Manitoba Hydro recognized that the economic prospects of the Conawapa Project in the near term were uncertain and encouraged the Panel to consider a "pathway" approach. This approach focuses on decisions that must be made in 2014 and acknowledges that there are other decisions that do not have to be made until a later date. Manitoba Hydro suggested that the two decisions that must be reached in 2014 are (1) whether to proceed with the Keeyask Project, and specifically, its planned 2019 in-service date, and (2) whether to proceed with the 750 MW interconnection.

Given the significant uncertainty involved in planning over a 78-year time frame, it is not feasible to approve a pathway with numerous future decision options.

I. Alternatives Evaluated

The Table below shows the 15 alternative development plans presented by Manitoba Hydro for analysis, listed in increasing order of required capital investment.

In the course of the NFAT, Manitoba Hydro took the position that several plans were no longer viable. Specifically, Manitoba Hydro indicated that any plans with a 250 MW interconnection are "hypothetical" as Minnesota Power has sought regulatory approval for a 750 MW line. This eliminates Plans 4, 11, and 13. Furthermore, Plans 5 and 14

were updated to reflect Wisconsin Public Service's unwillingness to invest in the U.S. segment of the transmission line.

Plans were analyzed through an initial economic screening. Manitoba Hydro conducted a full economic analysis on only 12 of the plans, and narrowed this down further to eight plans in its financial and rate impact analysis. In the course of the hearing, as updated assumptions became available, the list of plans was further narrowed.

Description of Manitoba Hydro's Development Plans

Plan	Short Name	Description
1	All Gas	Natural Gas-Fired Generation starting in 2022/23
2	K22/Gas	Keeyask 2022/23, Natural Gas-Fired Generation starting in 2029/30
3	Wind/Gas	Wind Generation starting in 2022/23 supported by Natural Gas-Fired Generation starting in 2025/26
4	K19/Gas24/250MW*	Keeyask 2019/20, Natural Gas-Fired Generation starting in 2024/25, 250 MW Export/50 MW Import U.S. Interconnection 2020/21, 250 MW MP Sale
5	K19/Gas25/750MW(WPS Sale & Inv)**	Keeyask 2019/20, Natural Gas-Fired Generation starting in 2025/26, 750 MW Import/Export U.S. Interconnection 2020/21, 250 MW MP Sale, Proposed 300 MW WPS Sale
6	K19/Gas31/750MW	Keeyask 2019/20, Imports, Natural Gas-Fired Generation starting in 2031/32, 750 MW Import/Export U.S. Interconnection 2020/21, 250 MW MP Sale
7	SCGT/C26	Simple Cycle Gas Turbine in 2022/23, Conawapa 2026/27, Natural Gas-Fired Generation starting in 2038/39
8	CCGT/C26	Combined Cycle Gas Turbine in 2022/23, Conawapa 2026/27, Natural Gas-Fired Generation starting in 2039/40
9	Wind/C26	Wind in 2022/23, Conawapa 2026/27, Natural Gas-Fired Generation starting in 2036/37
10	K22/C29	Keeyask 2022/23, Conawapa 2029/30, Natural Gas-Fired Generation starting in 2040/41
11	K19/C31/250MW*	Keeyask 2019/20, Natural Gas-Fired Generation starting in 2024/25, Conawapa 2031/32, 250 MW Export/50 MW Import U.S. Interconnection 2020/21, 250 MW MP Sale
12	K19/C31/750MW	Keeyask 2019/20, Imports, Conawapa 2031/32, Natural Gas-Fired Generation starting in 2041/42, 750 MW Import/Export U.S. Interconnection 2020/21, 250 MW MP Sale
13	K19/C25/250MW*	Keeyask 2019/20, Conawapa 2025/26, Natural Gas-Fired Generation starting in 2040/41, 250 MW Export/50 MW Import U.S. Interconnection 2020/21, 250 MW MP Sale
14	K19/C25/750MW (WPS Sale & Inv) Preferred Development Plan**	Keeyask 2019/20, Conawapa 2025/26, Natural Gas-Fired Generation starting in 2041/42, 750 MW Import/Export U.S. Interconnection 2020/21, 250 MW MP Sale, Proposed 300 MW WPS Sale
15	K19/C25/750MW	Keeyask 2019/20, Conawapa 2025/26, Natural Gas-Fired Generation starting in 2041/42, 750 MW Import/Export U.S. Interconnection 2020/21, 250 MW MP Sale

*Described as hypothetical due to Minnesota Power seeking regulatory approval for a 750 MW interconnection

**Adjusted to remove Wisconsin Public Service investment in the Great Northern Transmission Line

J. Economic Comparison of Alternatives

Manitoba Hydro has consistently taken the position that a “do nothing” approach is not an option, as new generation is eventually required to meet Manitoba demand for electricity. Accordingly, rather than analyze the 15 plans against a do-nothing scenario, Manitoba Hydro used the All Gas Plan as a baseline against which all other plans were evaluated.

Plans were subjected to different methods of economic analysis and compared to the All Gas Plan. The methods used included a determination of Net Present Value (NPV), internal rate of return and break-even year.

Over the course of the NFAT, Manitoba Hydro substantially and materially revised its assumptions, which caused the economics of the Preferred Development Plan to deteriorate. Whereas the NFAT Submission showed an incremental Net Present Value for the Preferred Development Plan of \$1.7 billion compared to the All Gas Plan, the revised assumptions reduced this amount to only \$45 million over 78 years. This was caused primarily by changes to the assumed capital cost of Keeyask and Conawapa as well as the assumed discount rate and increased DSM.

In contrast, a plan that involves the construction of Keeyask for a 2019 in-service date, the construction of the 750 MW interconnection, and a gas turbine in the later years of the plan, fared better. This plan compares favourably to both the All Gas Plan and the Preferred Development Plan. Deferring Keeyask to 2024 (the need for new supply in Manitoba) is less economic than to advance its in-service date to 2019. Furthermore, even if the 750 MW U.S. transmission interconnection should not receive regulatory approval in the United States, a plan that involves only Keeyask fares no worse than the All Gas Plan. As such, there is sufficient justification to proceed with a 2019 in-service date for the Keeyask Project.

There are realities of the Keeyask Project over which the Panel had no influence. Approximately \$1.2 billion has already been spent on the Keeyask Project. The \$3.2 billion Bipole III transmission line, which was not subject to the NFAT Review, has already received regulatory approval and will be constructed to carry northern electricity to southern Manitoba. Both of these were treated by Manitoba Hydro as “sunk costs”, and therefore excluded from the economic analysis.

Conawapa's economic benefits have not been demonstrated. Furthermore, Manitoba Hydro has not put forward a business case that supports protecting Conawapa's 2026 in-service date.

Gas generation is not a preferred alternative to Keeyask, as it is at least \$339 million less economic than the plan recommended by the Panel. While short-term capital costs may be lower, ongoing operating costs are higher, and the lifetime of gas turbines is only approximately one-third of that of a hydroelectric facility. This means a gas turbine of comparable size would have to be replaced twice during the lifetime of the Keeyask Project. The operating costs of a gas facility include the price of natural gas, which is volatile and forecast to increase from current decade-low prices. The burning of fossil fuels also creates significant greenhouse gas emissions, contradicting the Province's Clean Energy Strategy. Furthermore, the pursuit of the All Gas plan would not support the Minnesota Power export contract, which could lead to a loss of the 750 MW U.S. interconnection.

There are significant benefits associated with the 750 MW interconnection that go beyond the pure economics of the underlying export contract. Currently, Manitoba is interconnected with the MISO market through 1,950 MW of transmission capacity. An additional 750 MW interconnection provides increased electric reliability to Manitoba through additional capacity for imports in times of drought or infrastructure outages. The increased transmission capacity also opens new potential markets in the United States to Manitoba Hydro.

Similarly, wind power is not currently a preferred alternative to Keeyask. On its own, wind power is variable and requires backup capacity, either through a gas plant or hydraulic storage. While Manitoba Hydro's future cost projections for wind power are excessively conservative, wind power is currently less economic than other alternatives.

K. Financial Evaluation and Rate Impacts

All plans analyzed by Manitoba Hydro will require significant rate increases for a period of at least 20 years. Given the need to construct new generation by no later than 2024 and to repair or replace existing infrastructure, an approximate doubling of rates by 2032 is seen by Manitoba Hydro as inevitable. By 2032, Manitoba Hydro's projected increase in rates varies from 82% to 125% for different plans. This means that an average electricity bill in 2013 could double by 2032.

Manitoba Hydro's financial targets determine how rates are set. Targets include a self-imposed 75/25 debt-to-equity ratio. Manitoba Hydro's financial forecasts are premised on rates being increased sufficiently to allow the debt-to-equity ratio to recover to the target level over a 20-year time period, followed by lesser rate increases thereafter. During the NFAT Review, Manitoba Hydro also provided alternate suggested rate

methodologies that would increase rates more gradually, with the result of pushing back the date at which financial targets will fully recover.

A doubling of rates will have a significant effect on all ratepayers. This includes not just residential customers, but also commercial and industrial ratepayers, the latter of which are sensitive to price increases as it can affect their competitive position. The Panel supports a relaxation of Manitoba Hydro's 75/25 debt-to-equity ratio to smooth out rate increases and the Panel concludes that Manitoba Hydro would still be left with sufficient retained earnings if the equity level was decreased.

While some ratepayers have the option of switching to gas heat if electricity gets too expensive, this option is not available to many other Manitobans to whom gas is not available. These customers will be especially affected by rising rates, as they are dependent on electricity to meet their heating needs.

The Panel is particularly concerned about the impact the projected rate increases will have on lower income consumers, as it heard a substantial amount of evidence about the impact of electricity rates on the lower income segment of the population. This includes customers living in First Nation communities. Manitoba Keewatinowi Okimakanak (MKO) advised that in its First Nations 86% of accounts are currently in arrears, which signals significant affordability issues. However, to a large extent, cost increases can be mitigated by aggressive DSM, which can lead to overall savings.

While ratepayers will shoulder a significant rate burden over the next 20 years, the Province of Manitoba will reap substantial incremental revenues through capital tax and water rental payments from Manitoba Hydro as a result of the Keeyask Project. The Province should give serious consideration to using some of these incremental revenues to fund energy affordability programs targeted to vulnerable consumers, particularly lower income consumers and customers residing in northern and First Nation communities. This could involve rate relief programs as well as targeted DSM programs.

L. Economic Risk Factors

i. Capital Cost Uncertainty

Manitoba Hydro prepares Capital Expenditure Forecasts (CEFs) on an annual basis. Since CEF08, prepared in 2008, the capital cost projections for the Keeyask Project and Conawapa Project have increased in successive annual forecasts. At the start of the NFAT, Manitoba Hydro's capital cost projection was \$6.2 billion for the Keeyask Project

and \$10.2 billion for the Conawapa project. Manitoba Hydro's NFAT Business case was prepared based on these estimates.

The most recent capital cost estimates for the Keeyask Project and Conawapa Project are \$6.5 billion and \$10.7 billion respectively. This means that since Manitoba Hydro's NFAT evaluations were initially prepared, the projected cost for the Keeyask project has increased by \$300 million and the projected cost for the Conawapa Project has increased by \$500 million.

Manitoba Hydro executed the Keeyask general civil contract in early 2014. With that contract, approximately 80% of the Keeyask project has now been contracted. Manitoba Hydro assumes that this reduces cost uncertainty, but noted that the Wuskwatim hydroelectric project increased in cost by 10% from a similar project development stage as the Keeyask Project.

Manitoba Hydro's \$6.5 billion cost estimate is based on a "P50" estimate, meaning there is a 50/50 chance of costs being either lower or higher. This creates a higher risk of cost overruns than a more conservative P80 estimate. The Panel is also concerned that Manitoba Hydro's assumed escalation rate for construction materials and labour may be too conservative.

The Keeyask general civil contract is a costs-reimbursable contract rather than a fixed-price contract. This means that if volumes of materials increase, Manitoba Hydro is responsible for that increase. The Panel had the opportunity to consider the contract *in camera* as Commercially Sensitive Information, and has concluded that Manitoba Hydro bears a significant cost risk. There is a realistic possibility that the capital cost for the Keeyask Project may reach Manitoba Hydro's "high" cost scenario of \$7.2 billion, with a smaller possibility of total costs increasing beyond that amount.

With respect to Conawapa, which has a projected in-service date of 2026, there is significantly more cost uncertainty than for Keeyask, and the Panel has little confidence in the capital cost estimate for the Conawapa Project.

ii. Export Revenue Projections

Over the past decade, Manitoba Hydro has exported between 10,000-12,000 GWh of electricity annually. Its Preferred Development Plan is predicated on exports, and Manitoba Hydro currently predicts a cumulative \$6.9 billion of contracted firm energy revenues between 2015 and 2036. In addition, Manitoba Hydro projects approximately \$10.1 billion of opportunity sales into the spot market, for which prices fluctuate on a real-time basis. With respect to firm energy, the primary risk is that Manitoba Hydro will

not be able to obtain new contracts in the future on equally favourable terms, or at all. With respect to opportunity sales, the primary risk is that energy prices will be lower than projected.

Opportunity sales projections rely on a carbon price eventually developing in the United States, making them highly speculative. There is currently no clear consensus among different commercial export price forecasters regarding the timing and magnitude of carbon pricing. The MISO market is undergoing a period of significant transition, which could have the effect of negating Manitoba Hydro's competitive advantages. This includes the replacement of coal with other, cleaner, technology, which would decrease the environmental premium U.S. utilities will be willing to pay. Furthermore, to the extent any contractual counterparties are currently paying an implicit "carbon premium" on the expectation that carbon pricing will materialize, the failure of a carbon regime to develop could reduce firm export prices in future contracts. Lastly, if load growth in MISO ends up being less than projected, as a result of the reduced demand for electricity, opportunity prices may not be as high as assumed by Manitoba Hydro.

While the Panel has confidence in Manitoba Hydro's projection of \$6.9 billion of contract revenue, opportunity sale projections are optimistic, particularly if a carbon pricing regime does not materialize. In that case, domestic ratepayers are exposed to risk as they would have to make up any revenue shortfall.

M. Socio-Economic Evaluation

Manitoba Hydro conducted a Multiple Account Benefit/Cost Analysis for several plans, including the Preferred Development Plan. This analysis determines the net social benefits of each plan and how these benefits are distributed among Manitoba Hydro, ratepayers, the Government of Manitoba and provincial residents in general. Several non-monetary accounts are also considered. Two aspects of this analysis are noteworthy: the socio-economic benefits associated with each plan; and the implications for the Government of Manitoba's revenues.

In Manitoba Hydro's analysis, the Preferred Development Plan has the highest net social benefits. This is primarily due to the economic spin-offs associated with the construction phase of the Keeyask and Conawapa Projects. There would be significant leakages of spending out of the province, as only 45% of construction jobs are expected to be filled by Manitobans and major components such as turbines, cement and steel must be sourced from outside the province; nonetheless, the Preferred Development Plan has a larger impact on employment and income than the other plans.

The socio-economic benefits of the Keeyask Project are more tangible than those of the Conawapa Project. According to Manitoba Hydro's economic analysis, the Keeyask Project will create Manitoba labour income of over \$500 million, and almost 7,000 person-years of employment. The project will be developed through a partnership between Manitoba Hydro and four First Nations. These are Tataskweyak, War Lake, Fox Lake and York Factory, collectively known as the Keeyask Cree Nations (KCNs). Pursuant to the partnership agreement, significant benefits will flow to the four First Nations through preferred dividend distributions, directly negotiated contracts, and an aboriginal training and employment initiative. To reap the long-term benefits of such training and employment, ongoing professional development opportunities are likely required after Keeyask is completed.

At the NFAT Review, the KCNs spoke in support of the project and indicated that if Keeyask were to be delayed, it would not be easy to regain the momentum and start over. While the NFAT Panel heard dissenting views from some members of the KCN communities, such views represent a minority opinion, as referenda were held in each community.

With respect to the Government of Manitoba, substantial government revenues accrue from hydroelectric development, primarily through water rental fees and capital taxes paid by Manitoba Hydro. At a 3.0% discount rate, the 78-year Net Present Value of water rentals and capital taxes is \$6.1 billion for a plan that involves Keeyask and the 750 MW interconnection. This constitutes an additional benefit to the Province that is not captured in the results of Manitoba Hydro's economic evaluation, and dwarfs the incremental benefits flowing to Manitoba Hydro and its ratepayers.

N. Macro Environmental Evaluation

The Panel was asked to conduct a macro environmental evaluation of the Preferred Development Plan. The Panel interpreted and defined the term in accordance with the direction of the Province not to duplicate efforts undertaken by the Manitoba Clean Environment Commission, which, together with the federal Canadian Environmental Assessment Agency, has conducted an environmental assessment review of the Keeyask Project. No similar review has taken place for the Conawapa Project to date. The Clean Environment Commission recommended that a licence be issued for the Keeyask Project, with certain mitigation and monitoring conditions, including stocking of lake sturgeon for 50 years.

The Preferred Development Plan has significant Greenhouse Gas (GHG) benefits compared to alternatives, both in terms of avoided emissions and in terms of GHG

displacement in the MISO market, which is still heavily reliant on coal. The Panel's recommended plan has lower total emissions than all other technologies except wind and nuclear energy.

Nonetheless, both the Keeyask Project and the Conawapa Project will have adverse impacts, with the impacts of the Keeyask Project better known due to the environmental assessment review having already been completed. The most significant adverse effect of the Keeyask Project is its impact on lake sturgeon due to the disappearance of Gull Rapids and a risk of turbine mortality for adult lake sturgeon. Other adverse effects include impact on caribou, flooding, and temporarily increased methyl mercury levels as a result of leaching from flooded soil. To the extent such effects have not been mitigated, Manitoba Hydro has agreed to compensate affected First Nations through Adverse Effects Agreements.

Manitoba Hydro's hydroelectric plans have the lowest overall macro environmental impact when GHG savings are taken into consideration, with wind power being competitive with hydroelectricity from a macro environmental perspective. Nonetheless, the Panel heard from several affected First Nations communities about the effects of past hydropower developments, and one Intervener strongly suggested the need for a regional Cumulative Effects Assessment to be completed.

While the Preferred Development Plan has the greatest GHG displacement potential, the Panel notes that if Keeyask proceeds and Manitoba Hydro renews its emphasis on DSM, Conawapa is not required. The Panel further notes that in the future, other renewable technologies are likely to become commercially feasible.

The Panel's recommendations are aligned with Manitoba's Clean Energy Strategy, *The Climate Change and Emissions Reductions Act*, and the Principles of Sustainable Development as outlined in *The Sustainable Development Act*, and as such are consistent with the Province's goals for a clean energy future.

O. Integrated Resource Planning

The Terms of Reference required the Panel to consider "if preferred and alternative resource and conservation evaluations are complete, accurate, thorough, reasonable and sound."

By failing to offer an analysis of conservation measures as a stand-alone energy resource competitive with other generation resources, Manitoba Hydro presented an analysis of conservation measures that was neither complete, accurate, thorough, reasonable nor sound.

Integrated resource planning is a regular practice in many jurisdictions. An integrated resource plan determines what supply side and demand side resource mix is in the best interest of electricity customers. The Panel heard evidence that the best practices for integrated resource planning involve placing every resource option on an equal footing and a public consultative planning process. In contrast, Manitoba Hydro prepares an annual Power Resource Plan that is not developed through a public integrated resource planning process.

The NFAT Review demonstrated that DSM measures were not equally weighted with other energy options as they would have been if Manitoba Hydro had used an integrated resource planning process framework.

The effectiveness of integrated resource planning in determining least-cost combinations of resources cannot be overestimated.

To satisfy anticipated load growth to 2028/29, the Preferred Development Plan delivers 2,025 MW of additional capacity at an estimated cost of \$18.7 billion. If the supplementary 2014 Power Smart Plan DSM measures were treated as a stand-alone and equally weighted resource and added to the capacity from the Keeyask Project, the total capacity addition would be 1,766 MW at a projected cost, including transmission, of \$8.3 billion. This is more than 85% of the net system capacity addition of the Preferred Development Plan.

It was only in the course of the NFAT hearing that it became clear that significantly higher levels of DSM than originally proposed by Manitoba Hydro were both achievable and economic. Proper integrated resource planning could have reached that determination years earlier.

P. Panel Conclusions and Recommendations

Manitoba Hydro has not justified the need for its Preferred Development Plan and has not shown it to be superior to alternatives.

There are good reasons to proceed with the Keeyask Project at this time in light of the need for new resources, construction expenditures undertaken to date, the socio-economic and environmental benefits of the project, and the important commercial relations that Manitoba Hydro has established both with First Nations and through its export contracts. Moreover, there are associated reliability benefits with the 750 MW Transmission Interconnection Project.

In contrast, Manitoba Hydro's business case did not demonstrate the need for Conawapa and the associated North-South Transmission Upgrade. The risks associated with the Conawapa Project are unacceptable. It is too speculative in light of rapidly changing conditions in North American electricity markets.

Manitoba's energy future no longer lies exclusively with hydroelectricity. In a time of rapid technological innovation in both the demand and supply side, openness to alternative resources and new technologies will be required. This may involve new methods of saving electricity as well as new methods of generating it, such as wind and solar power. Integrated resource planning provides the analytical framework to evaluate such options and, as such, should be required before any further generating facilities beyond the Keeyask Project are constructed.

The Panel recommends the following:

Manitoba Hydro's Preferred Development Plan

1. The Panel recommends that the Government of Manitoba not approve Manitoba Hydro's proposed Preferred Development Plan.

Keeyask Project

2. The Panel recommends that the Government of Manitoba authorize Manitoba Hydro to proceed with the construction of the Keeyask Project to achieve a 2019 in-service date.

750 MW U.S. Transmission Interconnection Project

3. The Panel recommends that the Government of Manitoba authorize Manitoba Hydro to proceed with the 750 MW U.S. Transmission Interconnection Project for a 2020 in-service date.

Conawapa Project

4. The Panel recommends that the Government of Manitoba not approve the construction of the Conawapa Project and the North-South Transmission Upgrade Project.
5. The Panel recommends that the Government of Manitoba direct Manitoba Hydro to immediately cease any and all expenditures associated with the design, implementation, and future development of the Conawapa Project.

Creating New Demand Side Management Opportunities

6. The Panel recommends that the Government of Manitoba divest Manitoba Hydro of its responsibilities for Demand Side Management.
7. The Panel recommends that the Government of Manitoba mandate incremental annual Demand Side Management targets in the order of 1.5% of forecast domestic load (including codes and standards) over the long term.
8. The Panel recommends that the Government of Manitoba establish a regulated, independent arm's-length entity that would be responsible for developing and implementing a plan to meet the mandated Demand Side Management targets.
9. The Panel recommends that the Demand Side Management savings reported by the independent arm's-length entity be independently audited on an annual basis.
10. The Panel recommends that until the independent arm's-length entity is established, Manitoba Hydro continue to address the barriers to lower income customer participation in its Demand Side Management programs.
11. The Panel recommends that until the independent arm's-length entity is established, Manitoba Hydro proceed with its fuel switching and heating fuel choice initiatives to encourage customers to use natural gas for space and water heating.

Rates and Ratepayer Impacts

12. The Panel recommends that the Government of Manitoba direct a portion of the incremental capital taxes and water rental fees from the development of the Keeyask Project to be used to mitigate the impact of rate increases on lower income consumers, northern and aboriginal communities.
13. The Panel recommends that Manitoba Hydro relax its 75/25 debt-to-equity ratio policy to moderate its proposed electricity rate increases.
14. The Panel recommends that Manitoba Hydro implement cost containment measures to moderate its proposed electricity rate increases.

Actions in Support of a Clean Energy Future

15. The Panel recommends that integrated resource planning become a cornerstone of a new clean energy strategy for the Province of Manitoba.
16. The Panel recommends that the Government of Manitoba not approve the construction of any generating facilities, nor approve the beginning of the

required infrastructure work for any generation facility, beyond the Keeyask Project, unless such facilities are justified through an integrated resource planning process. The integrated resource planning process must include public consultation.

1.0.0 The Needs For and Alternatives To Review

1.1.0 Background

Manitoba Hydro has identified a need for new electricity resources based on its forecasts of future electricity demand in Manitoba and electricity export sale commitments. To meet this need, Manitoba Hydro examined a number of resource options and identified a Preferred Development Plan, which it believes will provide significant benefits to Manitobans and is the best option when compared to alternatives. This Plan, which consists of building the Keeyask and Conawapa generating stations, as well as associated transmission facilities, and a 750 MW transmission interconnection to the United States, has been approved by the Manitoba Hydro Electric Board and submitted to the Government of Manitoba for approval.

Under *The Manitoba Hydro Act*, Manitoba Hydro must have the Lieutenant Governor in Council's approval to develop new power generation stations and to supply power to other jurisdictions. Before it makes a decision, the Government of Manitoba may have Manitoba Hydro's development plans undergo a public review.

On January 13, 2011, the Government of Manitoba advised Manitoba Hydro that it intended to have an independent body conduct a Needs For and Alternatives To (NFAT) review of the proposed Keeyask and Conawapa generation projects and related transmission facilities. This notification was followed in late 2012 by an announcement from the then Minister of Innovation, Energy and Mines that the Government had asked the Public Utilities Board (PUB) to conduct the NFAT Review.

1.2.0 The Nature and Role of the Public Utilities Board

The Public Utilities Board is an arm's length, provincial, quasi-judicial body established under *The Public Utilities Board Act*. The Lieutenant Governor in Council appoints the Board's members. One of the PUB's main functions is to set "just and reasonable rates" that utilities such as Manitoba Hydro may collect from ratepayers for electricity and natural gas services. In addition to its general jurisdiction, the Board may, from time to time, perform additional duties assigned to it, such as those assigned by order of the Lieutenant Governor in Council under clause 107(b) of *The Public Utilities Board Act*.

1.3.0 Formation of the Needs For and Alternatives To (NFAT) Review

1.3.1. Order in Council and Terms of Reference

The NFAT Review was officially constituted on April 17, 2013 by Order in Council 128/13, whereby the Lieutenant Governor in Council assigned to the PUB, the conduct of a Needs For and Alternatives To Review (NFAT Review) of Manitoba Hydro's proposed Preferred Development Plan, which includes the Keeyask and Conawapa Generating Stations, their associated domestic alternating current transmission facilities, and a new international transmission interconnection.

The Order in Council sets out detailed Terms of Reference for the conduct of the NFAT Review (see Appendix 1). The Terms of Reference establish the subject matter and scope of the NFAT Review. The first component of the Review is a “needs for” analysis. In this regard, the Terms of Reference direct the PUB to assess whether the needs for Manitoba Hydro's Preferred Development Plan are “thoroughly justified and sound, its timing is warranted, and the factors that Hydro is relying upon to prove its needs are complete, reasonable and accurate.”¹ The second element of the Terms of Reference directs the PUB to examine the “alternatives to” the Preferred Development Plan and “whether the Plan is justified as superior to potential alternatives that could fulfill the need.”² The factors that must be considered in relation to both of these elements are outlined in the Terms of Reference.

1.3.2. Matters Not Within the Scope of the Review

There are a number of matters that the Government has decided to exclude from the scope of the NFAT Review. These matters are set out in the Terms of Reference and are listed below:

- The Bipole III transmission line and converter station project;
- The Pointe Du Bois project;
- Commercial arrangements between Hydro and its aboriginal partners for the development of the proposed hydro-electric generating stations (Keeyask and Conawapa);
- The environmental reviews of the proposed projects that are part of the Preferred Development Plan, including Environmental Impact Statements (subject to individual processes by the Manitoba Clean Environment Commission);

¹ Exhibit PUB-2, p. 2.

² Exhibit PUB-2, p. 2.

- Aboriginal consultation pursuant to section 35 of the *Constitution Act* (conducted as a separate Crown-Aboriginal consultation process);
- Past Manitoba Hydro development proposals or government assessments of past development proposals, including past NFATs; and
- Historic environmental costs.

1.3.3. Conduct of the NFAT Review

The Terms of Reference direct the Panel to conduct the NFAT Review in accordance with *The Public Utilities Board Act* and the Terms of Reference, and through “a transparent and public process.” The public was encouraged to provide input and comment on the Preferred Development Plan. In an effort to provide the public with access to the public information filed in the course of the Review, the PUB maintained a dedicated NFAT Review portal within the PUB’s website. All of the non-Commercially Sensitive Information, including documents, reports, filings, exhibits and testimony provided in the NFAT Review can be downloaded from the website of the Public Utilities Board at the following address: <http://www.pub.gov.mb.ca/nfat/index.html>.

1.3.4. Report to Government

The Order in Council directs the PUB to prepare a report on the matters outlined in the Terms of Reference and to present that report to the Minister responsible for the administration of *The Public Utilities Board Act* by June 20, 2014. The Report is to include recommendations to the Government of Manitoba on the needs for Manitoba Hydro’s Preferred Development Plan and an overall assessment as to whether or not the Plan is in the best long-term interest of the province of Manitoba when compared to other options and alternatives.³

1.4.0 Review Parties and Participants

1.4.1. The PUB NFAT Review Panel

Under the Terms of Reference, the Chair of the PUB is to designate an NFAT Panel from PUB members to carry out the NFAT Review. The Panel formed to conduct the Review consisted of Régis Gosselin, (Chair of the Panel and of The Public Utilities Board), and Board members Richard Bel, Dr. Hugh Grant, Marilyn Kapitany, and Larry Soldier. Mr. Bel and Dr. Grant were appointed as members of the Public Utilities Board for the purpose of participating in the NFAT Review by Order in Council 472/2013 on December 18, 2013.

³ Exhibit PUB-2, pp. 2-3.

1.4.2. Manitoba Hydro

As the proponent for the Preferred Development Plan, Manitoba Hydro had “applicant” status for the NFAT Review. It was Manitoba Hydro’s business case that was analyzed by the Panel. Throughout this Report, the business case is referred to as Manitoba Hydro’s NFAT Submission.

1.4.3. Interveners

Interveners are parties, usually umbrella organizations, which represent the perspectives of affected stakeholders. There is no right to Intervener status, but the Public Utilities Board has the discretion to permit Interveners. The function of Interveners is to assist the Board in a role akin to a “friend of the court.” Interveners have the right to adduce their own evidence and test the evidence of other parties.

The Board granted Intervener status to the following five organizations:⁴

- Consumers’ Association of Canada (Manitoba) Inc. (CAC)
- Green Action Centre (GAC)
- Manitoba Industrial Power Users Group (MIPUG)
- Manitoba Keewatinowi Okimakanak Inc. (MKO)
- Manitoba Métis Federation (MMF).

The Consumers’ Association of Canada (Manitoba) Inc. is an independent, non-profit, volunteer-based organization dedicated to educating and informing consumers and to representing the interests of consumers to all levels of government and sectors of society. CAC notionally represents Manitoba Hydro’s 456,130 residential customers. CAC has intervened in all rate applications before the PUB for electricity, natural gas, and auto insurance rates.

The Green Action Centre (formerly Resource Conservation Manitoba) is a non-profit, non-governmental organization, based in Winnipeg and serving Manitoba. GAC promotes greener living through environmental education and encourages practical green solutions for homeowners, workplaces, schools, and communities. Its primary areas of work are green commuting, composting and waste, sustainable living, resource conservation, and energy and climate change policy.

The Manitoba Industrial Power Users Group is an association of major industrial customers operating in Manitoba. Its members are: Amsted Rail - Griffin Wheel

⁴ Exhibit PUB-6.

Company (Winnipeg); Canexus (Brandon); Enbridge Pipelines Inc. (Southern Manitoba); ERCO Worldwide (Virden); Gerdau Long Steel North America – Manitoba Mill (Selkirk); HudBay Minerals Inc. (Flin Flon); Koch Fertilizer Canada ULC (Brandon); Tolko Industries Ltd. (The Pas); TransCanada Keystone Pipeline (Southern Manitoba); and Vale (Thompson). These customers work together on issues of common concern related to electricity supply and rates in Manitoba. Members' concerns are reflective of the size of their investments in Manitoba, the long-term view essential for such investments, and the requirement for continued large-scale purchases from Manitoba Hydro. Members' concerns also reflect competitive market pressures from selling Manitoba industrial products to external markets, and the need to secure the lowest reasonable costs for power and other production inputs to offset disadvantages from operating in Manitoba, such as transportation.

Manitoba Keewatinowi Okimakanak Inc. represents more than 65,000 treaty First Nation citizens in northern Manitoba. MKO has been in existence for over 32 years, and is a non-profit advocacy organization governed by the elected Chiefs of the 30 First Nations in northern Manitoba.

The Manitoba Métis Federation represents over 100,000 Manitoba Métis citizens at the local, regional, and provincial levels. The history and early beginnings of trade and industrial development in Manitoba are interwoven with the history of the Manitoba Métis community as founders of Manitoba. The MMF supports development in Manitoba as long as the development is handled in a manner that promotes sustainability and economic prosperity for the Manitoba Métis community and for all Manitobans.

The PUB approved Intervener funding for all five Interveners as provided for in its Rules of Practice and Procedure. Interveners were represented by legal counsel and were approved by the PUB to engage experts to undertake research, prepare reports and assist them in participating in the NFAT Review. Please see Appendix 4 of this Report for a listing of the Interveners and the issues they considered in relation to the Terms of Reference.

1.4.4. Independent Expert Consultants

The Terms of Reference also provide for the Panel to engage independent expert consultants (IECs) to assist it in the NFAT Review. The Terms of Reference outline a number of subjects that the IECs are to examine.

The Panel used a Request for Qualifications (RFQ) process to engage the IECs. A detailed Request For Qualifications document was finalized in June 2013 and approved by the Panel. Fifteen firms responded to the RFQ and eight were chosen as IECs, along

with another firm who was approved as a subcontractor to one of the chosen IECs. Detailed scopes of work were developed for each IEC in specific subject and issue areas. Independent legal counsel was also appointed for the IECs.

The following subject areas were addressed by IECs. Their detailed scopes of work can be found on the PUB website.

Table 1 List of Independent Expert Consultants

Independent Expert Consultant	Scope of Work (High-Level Description)
Elenchus Research Associates Inc.	Load forecasting, DSM, energy efficiency
La Capra Associates, Inc.	Power resource planning, economic evaluation, business case and risk analysis, transmission economics, export contracts, financial modelling
EnerNex (as a subcontractor to La Capra Associates, Inc.)	Wind matters
Knight Piésold Ltd.	Construction management, capital costs
MNP LLP	Macro-environmental issues
MPA Morrison Park Advisors Inc.	Commercial evaluation of Preferred Development Plan
Potomac Economics, Inc.	Midcontinent Independent System Operator (MISO), export markets, export prices and revenues
Power Engineers, Inc	Transmission line construction and management
TyPlan Consulting Ltd.	Socio-economic impacts and benefits

The IECs were engaged as independent arm's-length experts to provide an impartial, independent review of the matters assigned to them in their respective scopes of work and by the Terms of Reference. With a view to preserving that impartiality and independence, the PUB required all parties to the Review to follow a comprehensive communications protocol in relation to the IECs.⁵ The communications protocol established parameters for IEC interaction with the NFAT Review Panel and other members of the PUB NFAT Review team, including PUB staff, legal counsel, technical advisors, and the NFAT project manager. The protocol ensured that the IECs did not receive direct instruction from the NFAT Review Panel, aside from additions to their scopes of work. Inquiries between the PUB team and the IECs, other than those of a purely administrative nature, were routed through the IECs' independent legal counsel.

Parameters were also established in relation to the preparation and filing of the IECs' reports. IECs were not to share draft reports with the PUB team and their final reports were to be filed in evidence in the NFAT proceeding on the public record even if the NFAT Review Panel disagreed with their findings and conclusions. As required by the

⁵ Exhibit PUB-20, Appendix A, pp. 16-18.

Terms of Reference, the IECs' reports were to contain their analysis of the submissions filed by Hydro and were not to draw conclusions about the needs for or alternatives to the Preferred Development Plan; this being the remit of the Panel.⁶

1.4.5. Presenters

The Panel also heard from Presenters. Presenters are organizations or individuals who are not intervening in the proceedings, but who nevertheless wish to make their views known to the Panel. Presenters were able to provide their views in writing to the Panel or could appear before the Panel at the NFAT public hearings. Presenters made their presentations throughout the hearing process, as well as at designated presenter days in Winnipeg and Thompson, Manitoba. Summaries of the Presenters' reports and presentations are found in Appendix 6.

1.5.0 Review Process and Hearing

1.5.1. The Hearing

Following the issuance of the NFAT Terms of Reference on April 17, 2013, the Panel issued a public Notice of Pre-Hearing Conference in major newspapers across Manitoba and required Manitoba Hydro to serve past Interveners before the Public Utilities Board and the Clean Environment Commission. A pre-hearing conference to hear submissions with respect to process as well as applications for Intervener status took place on May 16, 2013. A further pre-hearing conference to deal with procedural matters took place on September 4, 2013.

Prior to the filing of Manitoba Hydro's NFAT Submission on August 16, 2013, Manitoba Hydro held a two-day technical conference for the Panel, IECs and approved Interveners to provide an overview of how the NFAT Submission business case would be organized and what information it would contain. A second technical conference was held in September 2013.

The hearings began on February 27, 2014 with non-evidentiary presentations received from registered Presenters. Presentations were also heard throughout the proceedings in Winnipeg and on May 14, 2014 in Thompson, Manitoba. The evidentiary portion of the hearing commenced on March 3, 2014 and ended on May 14, 2015. Closing submissions from Interveners were held on May 20 and May 21, 2014. Closing submissions from Manitoba Hydro were received on May 26, 2014. With the exception

⁶ Exhibit PUB-2, p. 4.

of the one-day session for Presenters in Thompson, Manitoba, all hearings were held in Winnipeg.

1.5.2. Filings and Records of the Hearing

Information Requests

The Board's Rules of Practice and Procedure allow the parties to make Information Requests of other parties. Following the filing of Manitoba Hydro's NFAT Submission on August 16, 2013, Interveners, IECs, and PUB Advisors submitted two rounds of written Information Requests. Manitoba Hydro challenged a number of Information Requests and questioned the volume of them. The Panel held a motions day on these issues on September 30, 2013, as a result of which it decided that certain Information Requests did not have to be answered. The Panel also encouraged all parties to obtain answers to Information Requests through informal discussion with Manitoba Hydro to the extent possible, thus reducing the number of formal written Information Requests to be answered.

The process also allowed for one round of Information Requests to IECs and Intervener experts, which was utilized by most parties to the hearing.

Filing of Evidence

Consistent with PUB practice, all documents relevant to the Review and within the scope of the Terms of Reference, except for Commercially Sensitive Information, were filed on the public record. These public documents were made available to the public on the PUB website. Commercially Sensitive Information was not publicly filed or made available on the website. In addition to the filing of Manitoba Hydro's NFAT Submission and responses to Information Requests, answers to undertakings and pre-asks were filed periodically throughout the oral evidentiary portion of the hearing.

1.5.3. Commercially Sensitive Information

The Panel obtained access to and considered Commercially Sensitive Information (CSI) to ensure that it was fully informed in reaching its conclusions and recommendations. CSI is described in the Terms of Reference as *"any information that may reasonably be expected to cause undue financial loss to Manitoba Hydro ... or any of its contractual counterparties or to harm significantly Hydro's or its contractual counterparties' or domestic customers' competitive position"....*⁷ This information included Manitoba Hydro's export contracts and term sheets for the purchase and sale of power and

⁷ Exhibit PUB-2, p. 6.

energy entered into between Manitoba Hydro and its U.S. customers, export price forecasts, Manitoba Hydro's yearly internal, non-public load forecasts, construction contracts, and Manitoba Hydro's existing and future Power Resource Plans.

The Panel was aware of the importance of conducting a transparent and public process, but also of its obligation to respect the commercially sensitive nature of some of Manitoba Hydro's information. Throughout the hearings, the Panel, in discussions with Manitoba Hydro and legal counsel, endeavored to find ways to make as much information publicly available as possible. As a result of these discussions, some of the information initially redacted as CSI was made publicly available with Manitoba Hydro's consent.

The IECs had access to CSI in preparing their reports. However, CSI was redacted from public versions of IECs' reports. The Panel held *in camera* proceedings to consider evidence based on Commercially Sensitive Information.

While this report does not contain or make direct reference to specific Commercially Sensitive Information, the Panel's conclusions and recommendations are informed by CSI evidence adduced during the *in camera* portions of the hearing.

1.5.4. Weighing of Evidence

In Appendix 7 the Panel has listed the names of the witnesses, and others, who have appeared at the NFAT Review.

It was the Panel's intention to record the names of all who have contributed to the Panel's better understanding of the myriad of complex issues, and the Panel regrets any omissions that may have occurred.

As the list discloses, the Panel heard evidence from over 75 witnesses. Even if the witness' name is not cited in the body of the Report, each and every witness assisted the Panel in its understanding of the issues and in reaching its decisions and recommendations.

As can be expected in a hearing of this magnitude, different witnesses provided different and sometimes opposing evidence on the same issue. In such cases, the Panel carefully weighed the evidence from the competing perspectives before arriving at its conclusions and recommendations.

The Panel again thanks all witnesses and parties for their dedication and professionalism in the NFAT Review.

2.0.0 Manitoba Hydro's Preferred Development Plan

2.1.0 Preferred Development Plan Components

Manitoba Hydro's Preferred Development Plan involves a major investment in new generation, transmission, and export contracts. At its core, the Preferred Development Plan involves the following components:

- The 695 megawatt (MW) Keeyask Project (\$6.5 billion), with a planned in-service date of 2019;
- The 1,485 MW Conawapa Project (\$10.7 billion), with a planned in-service date of 2026;
- The North-South Transmission Upgrade Project (approximately \$500 million), with an in-service date to coincide with the installation of the last turbine unit of Conawapa; and
- The 750 MW U.S. Transmission Interconnection Project terminating near Duluth, Minnesota (approximately \$1 billion).

2.1.1. The Keeyask Project

The Keeyask Project includes the construction of a 695 MW hydropower generating station located in northern Manitoba at Gull Rapids, as well as the development of ancillary transmission facilities.

The Keeyask Project is expected to take seven years to construct at a total estimated in-service cost of \$6.2 billion as of the time of Manitoba Hydro's NFAT Submission. This estimate has since been revised to \$6.5 billion.⁸ Construction of the preparatory support infrastructure began in 2012. Manitoba Hydro anticipates that construction of the generating station and transmission components will commence during the summer in 2014, after all necessary regulatory approvals have been received. Initial power production is anticipated for 2019, with all generating units in production by 2020. When fully operational, Keeyask is expected to produce an average of 4,400 gigawatt-hours (GWh) of electrical energy annually. Annual dependable energy production (the amount of energy that could be produced in the lowest-flow year on record) is projected to be 3,003 GWh.

⁸ Exhibit MH-113.

The generating facility is being developed through the Keeyask Hydropower Limited Partnership (KHLP), a partnership between Manitoba Hydro and four First Nations, namely the Tataskweyak Cree Nation, War Lake First Nation, Fox Lake Cree Nation and York Factory First Nation. The commercial terms of the arrangement are set out in the Joint Keeyask Development Agreement (JKDA). A review of these terms was excluded from the scope of the NFAT Review.

The Partnership will contract the planning, construction, and operation of the generation and infrastructure projects to Manitoba Hydro. Manitoba Hydro will then subcontract most of the services and supplies required to build the project. In addition, Manitoba Hydro will be contracted to provide the required debt financing for the projects. KHLP will sell all the power produced at the generating station to Manitoba Hydro.

Manitoba Hydro will own and operate the transmission infrastructure required for the Keeyask generating station.

2.1.2. The Conawapa Project

The Conawapa Project includes the construction of a 1,485 MW hydroelectric generating station downstream of the Limestone generating station, as well as the development of ancillary transmission facilities.

The Conawapa Project is expected to take over 10 years to construct at a total estimated in-service cost of \$10.2 billion as of the time of the filing of Manitoba Hydro's NFAT Submission. This estimate has since been revised to \$10.7 billion.⁹ In its August 2013 submission, Manitoba Hydro anticipates that construction of the generating station will commence in 2017. Initial power production is projected for May 2026; with all generation units in production by October 2027. Final decommissioning of temporary infrastructure and site rehabilitation is slated for completion in 2028. When fully operational, Conawapa is expected to produce an average of 7,000 gigawatt-hours (GWh) of electrical energy annually.

2.1.3. North-South Transmission System Upgrade Project

Manitoba Hydro's high-voltage direct current (HVDC) transmission system, which will include Bipole III, will be used to transmit the power to be produced at the Conawapa Generating Station. However, certain upgrades to the exiting northern alternating current and high-voltage direct current system are required to transmit the remaining power. These upgrades are described in Manitoba Hydro's NFAT Submission as the

⁹ Exhibit MH-113.

North-South Transmission System Upgrade Project. The Upgrade Project consists of two main elements:

- Upgrades to the existing northern 230 kV alternating current (AC) transmission system; and
- Upgrades to the existing HVDC transmission system within or in the immediate vicinity of the Radisson Converter Station and Kettle Generating Station in the north and the Riel Converter Station in the south.

The proposed in-service date for the Project is to coincide with the in-service date of the last Conawapa generating units. The initial, estimated capital cost for the North-South Transmission System Upgrade Project is \$340 million (in \$2012).¹⁰

2.1.4. Manitoba-Minnesota Transmission Project

The proposed Manitoba-Minnesota Transmission Project is a single circuit 750 MW, 500 kV alternating current (AC) transmission line starting at the existing Dorsey Converter Station south of Winnipeg, and connecting at the Manitoba-Minnesota border to the Great Northern Transmission Line, a new transmission line proposed by Minnesota Power. The projected in-service cost for the Manitoba portion of the project is \$350 million.

2.1.5. Great Northern Transmission Line

The Great Northern Transmission Line is a new 750 MW, 500 kV AC transmission line proposed by Minnesota Power, one of Manitoba Hydro's contractual counterparties, in Minnesota. In the north, it would join with the Manitoba-Minnesota Transmission Project described above. In the south, it would terminate in the Iron Range near Duluth, Minnesota.

While the Great Northern Transmission Line is proposed and being developed by Minnesota Power, Manitoba Hydro plans to have a 49% ownership stake in the line, effectively funding a portion of construction and operating expenses. Manitoba Hydro intends to fund 67% of the line, but has expressed hope that it will eventually be able to sell its ownership stake. The total projected construction cost is in the vicinity of US\$700 million. Construction is anticipated to begin in 2016, for an in-service date of 2020.

¹⁰ Exhibit MH-95, p. 85.

2.2.0 The Preferred Development Plan and its Alternatives

In its NFAT Submission, Manitoba Hydro presented 14 alternative plans in addition to the Preferred Development Plan. These alternatives had been prepared to help test the Preferred Plan, as well as illustrate other resource options. These alternatives are presented in the Table below.

The plans fall into three main categories:

- four plans with a 750 MW U.S. interconnection;
- three plans with a 250 MW U.S. interconnection; and
- seven plans that, starting in 2022/23, meet Manitoba Hydro's domestic load and existing firm export commitments with no new U.S. interconnection.

2.2.1. Pathways

As a part of its planning, Manitoba Hydro prepared a number of pathways that would guide decisions on both the introduction of new generation, and their logical timing and order.¹¹ The Figure at the end of this chapter¹² presents the final version of the pathways that include the proposed actions associated with all of the new generation options and facilities: the construction of the Keeyask and Conawapa Projects, the construction of the transmission line, and the introduction of Demand Side Management (DSM) Level 2 initiatives.

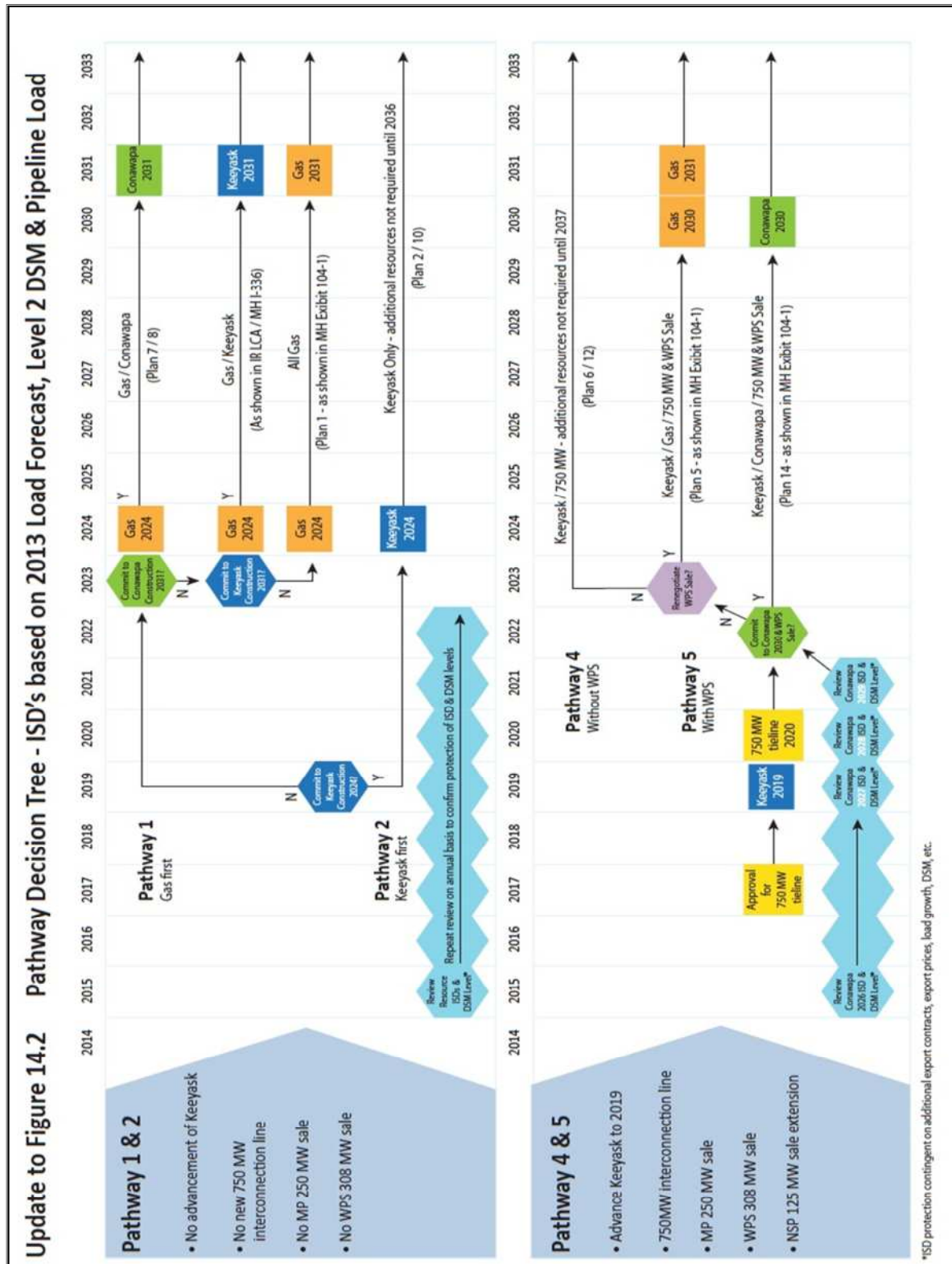
¹¹ Manitoba Hydro NFAT Submission, Chapter 14, pp. 5-6.

¹² Exhibit MH-192 p.1.

Table 2 Description of Manitoba Hydro's Development Plans

Plan	Short Name	Description
1	All Gas	Natural Gas-Fired Generation starting in 2022/23
2	K22/Gas	Keeyask 2022/23, Natural Gas-Fired Generation starting in 2029/30
3	Wind/Gas	Wind Generation starting in 2022/23 supported by Natural Gas-Fired Generation starting in 2025/26
4	K19/Gas24/250MW	Keeyask 2019/20, Natural Gas-Fired Generation starting in 2024/25, 250 MW Export/50 MW Import U.S. Interconnection 2020/21, 250 MW MP Sale
5	K19/Gas25/750MW(WPS Sale & Inv)	Keeyask 2019/20, Natural Gas-Fired Generation starting in 2025/26, 750 MW Import/Export U.S. Interconnection 2020/21, 250 MW MP Sale, Proposed 300 MW WPS Sale
6	K19/Gas31/750MW	Keeyask 2019/20, Imports, Natural Gas-Fired Generation starting in 2031/32, 750 MW Import/Export U.S. Interconnection 2020/21, 250 MW MP Sale
7	SCGT/C26	Simple Cycle Gas Turbine in 2022/23, Conawapa 2026/27, Natural Gas-Fired Generation starting in 2038/39
8	CCGT/C26	Combined Cycle Gas Turbine in 2022/23, Conawapa 2026/27, Natural Gas-Fired Generation starting in 2039/40
9	Wind/C26	Wind in 2022/23, Conawapa 2026/27, Natural Gas-Fired Generation starting in 2036/37
10	K22/C29	Keeyask 2022/23, Conawapa 2029/30, Natural Gas-Fired Generation starting in 2040/41
11	K19/C31/250MW	Keeyask 2019/20, Natural Gas-Fired Generation starting in 2024/25, Conawapa 2031/32, 250 MW Export/50 MW Import U.S. Interconnection 2020/21, 250 MW MP Sale
12	K19/C31/750MW	Keeyask 2019/20, Imports, Conawapa 2031/32, Natural Gas-Fired Generation starting in 2041/42, 750 MW Import/Export U.S. Interconnection 2020/21, 250 MW MP Sale
13	K19/C25/250MW	Keeyask 2019/20, Conawapa 2025/26, Natural Gas-Fired Generation starting in 2040/41, 250 MW Export/50 MW Import U.S. Interconnection 2020/21, 250 MW MP Sale
14	K19/C25/750MW (WPS Sale & Inv) Preferred Development Plan	Keeyask 2019/20, Conawapa 2025/26, Natural Gas-Fired Generation starting in 2041/42, 750 MW Import/Export U.S. Interconnection 2020/21, 250 MW MP Sale, Proposed 300 MW WPS Sale
15	K19/C25/750MW	Keeyask 2019/20, Conawapa 2025/26, Natural Gas-Fired Generation starting in 2041/42, 750 MW Import/Export U.S. Interconnection 2020/21, 250 MW MP Sale

Figure 1 Pathways Identified by Manitoba Hydro



2.2.2. Developments During the NFAT Review

Manitoba Hydro made a number of changes that affected the economics of the Preferred Development Plan during the course of the NFAT hearing. On March 10, 2014, Manitoba Hydro updated its capital costs estimates for both Keeyask and Conawapa.¹³ The update showed increases in the construction cost estimate for Keeyask from \$6.2 billion to \$6.5 billion and for Conawapa from \$10.2 billion to \$10.7 billion. Manitoba Hydro also explained that Wisconsin Public Service would not be investing in the proposed 750 MW transmission interconnection while still committing to purchase 308 MW of power from Manitoba Hydro. “

At that same time, Manitoba Hydro also provided information on the impact of increased Demand Side Management efforts and the potential for future pipeline industry load.¹⁴ Its new Power Smart Plan envisions its customers switching from electricity to gas, where available, for space and water heating, conservation rates for domestic customers and self-generation by industrial customers.¹⁵ The increased Demand Side Management will have the potential to delay the domestic need for new generation beyond 2022, which was the year Manitoba Hydro forecasted that new generation would be needed in its NFAT Submission.

¹³ Exhibit MH- 95.

¹⁴ Exhibit MH- 95.

¹⁵ Exhibit MH-153.

3.0.0 Alignment with Applicable Legislative and Policy Documents

3.1.0 Introduction

In its Terms of Reference, the Panel was asked to consider the alignment of the Preferred Development Plan and its proposed alternatives to a number of acts and strategies. These were *The Manitoba Hydro Act*, the *Manitoba Clean Energy Strategy*, *The Change and Emissions Reductions Act*, and the sustainable development principles, as outlined in *The Sustainable Development Act*.

3.2.0 The Manitoba Hydro Act

The Terms of Reference specifically direct the Panel to consider the alignment of the proposed Preferred Development Plan with Manitoba Hydro's mandate as stated in section 2 of *The Manitoba Hydro Act*. That section states the following:

Purposes and Objects of Act

2. The purposes and objects of this Act are to provide for the continuance of a supply of power adequate for the needs of the province, and to engage in and to promote economy and efficiency in the development, generation, transmission, distribution, supply and end-use of power and, in addition, are

(a) to provide and market products, services and expertise related to the development, generation, transmission, distribution, supply and end-use of power, within and outside the province; and

(b) to market and supply power to persons outside the province on terms and conditions acceptable to the board.

In the Panel's interpretation, Manitoba Hydro's foremost purpose under section 2 of the *Act* is to ensure that Manitobans have adequate access to electrical power at all times. All plan alternatives presented by Manitoba Hydro are focused on meeting domestic load growth, providing reliable power, and anticipating load growth challenges.

The *Act* also directs Manitoba Hydro to seek economies and efficiencies in its development, generation, transmission, distribution, supply, and end-use of power. In the Panel's interpretation, this involves several things. First, while the *Act* does not mandate Manitoba Hydro to choose the lowest-cost generation source, it requires a

careful analysis of the economic and financial impacts of alternative choices. Second, it involves an obligation on Manitoba Hydro to act efficiently and avoid unnecessary costs. Third, it requires a focus on energy efficiency and Demand Side Management, with a legitimate focus on end-use of power. In the Panel's view, while all alternative plans involving a significant focus on Demand Side Management are broadly aligned with these requirements, the focus on economics and efficiency mandated by the *Act* underlines the Panel's conclusions about new investments in generation.

The Manitoba Hydro Act further provides for the marketing of products, services and expertise, as well as direct export sales to external customers in Canadian provinces beyond Manitoba and in the United States. In the Panel's view, this section is permissive, that is, while it allows Manitoba Hydro to engage in these activities, it does not mandate the utility to do so. As such, Manitoba Hydro should only pursue them if it is in the economic interest of Manitoba ratepayers to do so.

In its Preferred Development Plan and corporate plans and documents, Manitoba Hydro points to the value and importance of export sales as a means of supporting new generation costs and moderating domestic rates. As was indicated in its Preferred Development Plan, Manitoba Hydro looks to “surplus by design” to take advantage of export sales opportunities. In fact, Manitoba Hydro sees a limited “window of opportunity” available to capitalize on the need of external customers to seek out renewable energy sources.

3.3.0 Manitoba's Clean Energy Strategy

Released in December 2012, the Manitoba Clean Energy Strategy outlines proposed goals and actions in five areas: (1) building a new Manitoba Hydro; (2) leading Canada in energy efficiency; (3) keeping rates low; (4) growing renewable alternatives; and (5) freedom from fossil fuels.

The Clean Energy Strategy suggests that “by advancing the construction of new hydro plants ahead of domestic needs, Manitoba can both earn additional export revenues and expand valuable interconnection transmission, while also building the plants it will need to meet its own future requirements.”¹⁶

In addition, the Strategy envisages a new Manitoba Hydro having a clean energy portfolio which would add wind and other emerging, renewable energies, as well as energy efficiency initiatives, improved transmission, and the rehabilitation of older

¹⁶ Exhibit PUB 58-5, p.337.

projects.¹⁷ Notably, the Strategy does not require Manitoba Hydro to proceed with construction, but only requires the proposed new generating stations to proceed through environmental and economic review.¹⁸

The Strategy also describes Manitoba's energy efficiency efforts and achievements. It notes the Province's ability within a few years of becoming a leader in Canada. The Strategy proceeds to outline a number of priority actions for the future, including new programs and funding for residential energy efficiency improvements.¹⁹

The Clean Energy Strategy celebrates the fact that the cost of electricity in Manitoba has been among the lowest in Canada. It endeavours to maintain a "low utility rate advantage"²⁰ through predictable, modest rates increases for Manitoba Hydro over the coming years.²¹

The Strategy observes that there has been a growth in the range of renewable energy technologies, such as wind, heat pumps, and electric vehicles. It outlines efforts in a number of areas where new priorities will be given to new initiatives. These areas include wind, solar, geothermal heat pumps, and electric vehicles. In particular, the Strategy talks about the opportunities, advantages, and goals associated with wind power. It describes the expected economic benefits to come from the St. Leon and St. Joseph wind farms. The Strategy sets out the goal of an additional 1,000 MWs of economically developed new wind.²²

Manitoba Hydro has taken the position that it is more economic to import wind energy from the United States. It has a wind exchange agreement beginning in 2020 with Minnesota Power pursuant to which U.S. wind power is stored in Manitoba Hydro's reservoirs. However, several Interveners criticized Manitoba Hydro's assumptions with respect to the cost of wind energy. The Panel is of the view that a decision to proceed with Keeyask will likely delay the development of any additional wind power in Manitoba, as Keeyask adds a significant amount of dependable energy to Manitoba Hydro's system, negating the need for new generation for at least a decade.

The Strategy concludes with a commitment to move away from fossil fuels as an energy source for Manitoba. In addition to highlighting a number of specific initiatives, the Strategy notes Manitoba Hydro's own action in this regard. The Panel would note that

¹⁷ Exhibit PUB 58-5, p.341.

¹⁸ Exhibit PUB 58-5, p.330.

¹⁹ Exhibit PUB 58-5, pp.346-354.

²⁰ Exhibit PUB 58-5, p.354.

²¹ Exhibit PUB 58-5, p.355.

²² Exhibit PUB 58-5, p.375.

the Preferred Development Plan and many of its alternatives support this goal of the Clean Energy Strategy. Some alternatives do involve gas thermal generation, but in supporting roles to hydropower. However, one should not forget that during periods of off-peak imports, Manitoba Hydro is likely importing coal-generated energy from the United States.

3.4.0 The Climate Change and Emissions Reductions Act

The Climate Change and Emissions Reductions Act stipulates that Manitoba Hydro must not use coal to generate power, with the exception of emergencies.²³ The Panel notes that the Preferred Development Plan and its alternatives do not propose to use or develop coal to generate power. As such, all proposed plans are aligned with this statute.

3.5.0 Principles of Sustainable Development (as outlined in The Sustainable Development Act)

In 1998, the Province of Manitoba enacted *The Sustainable Development Act* to “create a framework through which sustainable development will be implemented in the provincial public sector and promoted in private industry and in society generally” (Government of Manitoba 1998). The principles and guidelines of sustainable development are appended to the statute. These principles are: integration of environmental and economic decisions, stewardship, shared responsibility and understanding, prevention, conservation and enhancement, rehabilitation, and global responsibility.

Manitoba Hydro provided the Panel with evidence as to how its plans and actions are aligned with these principles.²⁴ For example, Manitoba Hydro has integrated environmental factors into its economic decisions. Stewardship and defined, shared responsibilities are evident in its agreements with the Keeyask Cree Nations. Manitoba Hydro's environmental mitigation and adverse effects agreements address prevention and conservation considerations.

It is readily apparent to the Panel that both the Preferred Development Plan and the plan recommended by the Panel will yield some residual effects. This includes the environmental impact of flooding, erosion, and the destruction of sturgeon habitat, as well as long-term rate impacts on consumers.

²³ Exhibit PUB - 62, pp. 1-2.

²⁴ Manitoba Hydro NFAT Submission, Appendix 14.1, pp. 1-12.

3.6.0 Conclusions of the Panel

It is the Panel's view that the Preferred Development Plan and the proposed Alternative Plans are aligned with *The Manitoba Hydro Act*, the Manitoba Clean Energy Strategy, *The Climate Change and Emissions Reductions Act*, and the sustainable development principles outlined in *The Sustainable Development Act*.

The Panel finds that all alternative plans are broadly aligned with section 2 of *The Manitoba Hydro Act*, so long as the economic and financial repercussions of each plan are sound.

In particular, the Panel notes that the 2012 Clean Energy Strategy provides a basis for the Panel's thinking about what is needed to achieve a new energy future. The Panel shares the Strategy's conclusions as to the importance of Demand Side Management initiatives, the need for a greater portfolio of renewable resource options, and the need to keep rates low. In particular, the Panel agrees with the goal of making Manitoba a leader in energy efficiency initiatives.

4.0.0 Domestic Need and Load Forecast

4.1.0 Introduction

Manitoba Hydro's mandate under section 2 of *The Manitoba Hydro Act* includes "providing for the continuance of a supply of power adequate for the needs of the province." To ensure there is an adequate, reliable supply of power to meet demand, Manitoba Hydro must plan ahead by looking at current energy demand, future energy requirements, and the ability of existing power resources to meet those requirements. In carrying out its mandate, Manitoba Hydro annually forecasts the expected future electricity needs of Manitoba residences, commercial businesses, industries, and institutions as part of its power resource planning process.

The Terms of Reference direct the Panel to examine the "*reasonableness, thoroughness and soundness of all critical inputs and assumptions Hydro relied on to justify the needs. This should include Hydro's planning load forecast and future load scenarios, its demand and supply analysis, export expectations and commitments and demand side management and conservation forecasts.*"²⁵

4.2.0 The Components of Manitoba's Electricity Demand

4.2.1. Energy and Capacity Demands

There are two components to Manitoba's electricity demand, namely energy and capacity. Energy, measured in kilowatt-hours (kWh) or gigawatt-hours (GWh), is the total quantity of power consumed over a certain timeframe. Capacity, measured in megawatts (MW), is the amount of electricity consumed at a point in time. Manitoba Hydro must be able to supply sufficient energy to meet its customers' needs over a period of time, such as a season or year, as well as sufficient generating capacity to meet the peak demands of its customers. Manitoba Hydro's 2013 Electric Load Forecast provides a forecast for Manitoba's Gross Firm Energy requirements in GWh and Gross Total Peak demand in MW assuming normal weather.

Gross Firm Energy is the total annual energy required for Manitoba Hydro's domestic customers on the integrated electricity grid. Gross Total Peak is the maximum amount of power needed to serve Manitoba Hydro's grid-based customers at any given time. Because Manitoba is a winter-peaking jurisdiction, peak domestic load occurs in winter, typically on a very cold weekday. For generation planning purposes, Manitoba Hydro reduces the Gross Firm Energy and Gross Peak Demand by forecasted DSM savings.

²⁵ Exhibit PUB-2, p. 2, Item 1.

The forecast of Gross Firm Energy is derived from the energy forecasts for the individual sectors that make up total domestic load. These sectors are comprised of major customer groups — Residential Basic, General Service - Mass Market, and General Service - Top Consumers — and other components such as Losses (losses associated with the transmission and distribution of electricity over power lines) and Station Service (energy used by power plants to generate power and service their own load), and miscellaneous customers such as seasonal customers, flat rate water heating customers, and area and roadway lighting.

Manitoba Hydro's analysis filed in its NFAT Submission was based largely on its 2012 Electric Load Forecast, which covers the 20-year period to 2031/32. Manitoba Hydro also included further analysis based on updated information from the 2013 Electric Load Forecast (2013 Load Forecast). The 2013 Load Forecast estimates Manitoba's energy needs and peak demand requirements for the 20-year period from 2012/13 to 2032/33. In the 2013 Load Forecast, Manitoba Hydro forecasts Gross Firm Energy to grow at the rate of 1.5% (413 GWh) per year over the next 20 years to 32,667 GWh by 2032/33. Gross Total Peak is expected to grow by 76 MW (1.5%) per year to reach 5,959 MW by 2032/33. Manitoba Hydro has not specifically provided load growth beyond 2033, but it can be calculated as being 1.1% (with DSM Level 2 as explained in Chapter 5) out to 2049.²⁶

Compared to the 2012 Load Forecast, the 2013 Load Forecast shows a 1,159 GWh (3.5%) reduction in Gross Firm Energy by 2031/32, which is equivalent to almost three years of annual load growth. Forecast Gross Total Peak in the 2013 Load Forecast shows a decline of 146 MW (2.4%) by 2031/32, amounting to a reduction of almost two years of load growth. Lower forecasted population growth and delays in the plans of two industrial power customers were largely responsible for the reductions in forecasted demand between the 2012 and 2013 Load Forecasts.

Manitoba Hydro stated that its 2014 Electric Load Forecast will not be ready in time for the Panel to consider it during the NFAT Review. However, Manitoba Hydro identified the following potential adjustments to its upcoming 2014 Load Forecast.²⁷

²⁶ Exhibit MH-104-3, p.6.

²⁷ Exhibit MH-87, p. 12.

Table 3 Load Forecast Adjustments to Manitoba Hydro's 2014 Load Forecast

Change Item	Impact – GW.h	Date
Pipeline Sector	1700 GW.h*	2019/20
Codes and Standards	(300) GW.h	2027/28
Price Elasticity	(500-600) GW.h	2027/28
Fuel Choice	(100) GW.h	2027/28

4.2.2. Main Customer Components

The three main customer groups (Residential Basic, General Service – Mass Market, General Service – Top Consumers) are the most significant components of Manitoba Hydro's load and contribute most of Manitoba Hydro's revenue. Manitoba Hydro uses a different methodology for forecasting the energy requirements of each customer group and has made a number of changes to its forecasting methodologies over time. Manitoba Hydro is forecasting growth in consumption across all customer groups, resulting in overall load growth that is slightly higher than the Canadian average, and slightly lower than the U.S. average.²⁸

Residential Basic

The Residential Basic sector consists mainly of single detached dwellings, multi-attached dwellings, and individually metered apartments. In 2012/13, there were 456,130 Residential Basic customers comprising 33.6% of domestic sales.

The primary drivers of growth in this sector are population increases (largely attributable to immigration) and greater reliance on electricity for space and water heating. Manitoba Hydro is forecasting increased use of electricity for space and water heating. Projections in the 2013 Load Forecast indicate that by 2032/33, approximately 40% of Residential Basic customers will be using electricity as a heating source, an increase of 3% from 2013 levels. The number of residential customers using electric water heating is expected to climb to nearly two-thirds by 2032/33. However, in its 2014 Power Smart Plan, Manitoba Hydro expects to achieve significant electricity savings through a fuel switching program and conservation rates, both of which could encourage electric space and water heat customers to switch to gas. If implemented, such measures may reverse this trend. Fuel switching is discussed in greater detail in Chapter 5.

²⁸ Exhibit MH-87, p. 8.

General Service - Mass Market

The General Service - Mass Market sector is comprised of commercial and industrial customers such as offices, retail and wholesale businesses, schools, hospitals, agriculture, apartment complexes, manufacturing, and industrial customers that do not fall within the Top Consumers sector. In 2012/13, there were 65,974 General Service - Mass Market customers accounting for approximately 39.3% of electricity sales. The main drivers for growth in the General Service – Mass Market sector are growth in the number of Residential Basic customers and the forecast Gross Domestic Product (GDP) for Manitoba, which Manitoba Hydro currently estimates will grow by 2% over the long term.²⁹

General Service – Top Consumers

The General Service – Top Consumers category is comprised of 31 customers made up of 17 companies in sectors such as primary metals, chemicals, petrol/oil/natural gas, pulp/paper, food/beverage, and colleges/universities. This sector accounts for approximately 22.8% of load.

Energy consumption by Top Consumers grew by 91 GWh (2.0%) per year over the past 20 years. Growth over the past 10 years, however, was down considerably, at only 28 GWh per year (0.5%). The economic downturn from 2008 to 2011 and the loss of one major customer in this sector significantly reduced the 10-year growth rate. Manitoba Hydro is forecasting energy consumption to increase by 1.6% or 103 GWh per year over the next 20 years, similar to growth over the past 20 years despite the pending closure of the Vale smelter and refinery in Thompson circa 2016/17.

Manitoba Hydro uses a two-pronged approach to forecasting load in this sector comprised of shorter-term (3-5 years) individual forecasts for each member of the sector and a longer-term potential load calculation, “Potential Large Industrial Loads” or “PLIL.” PLIL is used to represent the sector’s overall growth, including major expansions, as well as the addition and loss of customers. Starting in 2016/17, 100 GWh a year is forecast for PLIL to account for unforeseen expansion, contraction, and growth.

In addition to PLIL, Manitoba Hydro also considers it likely that 1,700 GWh of additional load will arise by 2019/20³⁰ from upgrades to pipeline pumping stations within Manitoba. Enbridge’s Alberta Clipper pipeline, Enbridge’s planned upgrades to its Line 3 pipeline, and TransCanada Pipeline’s Energy East pipeline project, which involves the conversion of a portion of TransCanada’s Mainline gas pipeline to oil, will result in

²⁹ Manitoba Hydro NFAT Submission, Appendix G, p. 6.

³⁰ Exhibit MH-87, p.12.

1700 GWh of additional load. The Line 3 upgrade and the Energy East project are currently before the National Energy Board, while the remaining pipeline expansions, with their resulting electric load, have already received National Energy Board approval.³¹ Four hundred GWh of that pipeline load are incorporated in Manitoba Hydro's 2013 Load Forecast as PLIL projections.³²

4.3.0 Load Forecasts

4.3.1. Load Forecasting Methodology

Because the customer sector forecasts play such an important role in Manitoba Hydro's load forecast, there was a considerable amount of discussion before the Panel about the methodologies that Manitoba Hydro employs to develop these forecasts.

Manitoba Hydro employs an end-use model to forecast energy demand in the Residential Basic sector. The model determines electricity use based on assumptions about the numbers of customers, dwelling type, location within Manitoba, appliance age and saturation, and the number of customers who use electricity for space and water heating. These assumptions rely on information from Manitoba Hydro's 2009 Residential Survey.

With respect to the Residential Basic forecast, Elenchus identified a number of concerns, ranging from problems with the method of forecasting the residential customers' market share of electric heat and failing to account for potential changes in population growth, to reliance on a static person-per-household ratio and dated (2009) survey data that may not reflect current conditions.

Economic and Population Demand Scenarios

Experts testifying on behalf of CAC raised the issue of testing the effect of different economic and population scenarios on demand. The Residential Basic and General Service – Mass Market sectors' forecasts are heavily influenced by population and economic growth.³³ The Panel learned that the projected growth in Manitoba's population could be lower than the future growth projected in the 2013 Load Forecast, based on three of the five updated population forecasts relied upon by Manitoba Hydro.³⁴ Even with these concerns, Elenchus noted that there have not been significant errors in recent Residential Basic forecasts when compared to actual consumption.

³¹ Transcript, pp. 1137-1140.

³² Exhibit MH-104-3, pp. 59,83.

³³ Exhibit CAC-25, p. 8.

³⁴ Exhibit MH-93.

However, over the longer-term 20-year forecast period, the concerns identified could “cause more significant deviations.”³⁵

The Top Consumers sector was singled out as the source of the highest forecasting error. Elenchus pointed to consistent over-forecasting in recent years, as well as previous periods of both under-forecasting and over-forecasting. Elenchus maintained that the PLIL projection is particularly sensitive to economic conditions, as was evidenced by the economic downturn in the last decade, and would benefit from sensitivity testing against high, medium and low economic conditions.³⁶ Similarly, Patrick Bowman, an expert witness for the Manitoba Industrial Power Users Group (MIPUG) noted that *“the most significant weakness for the industrial load forecast, from the perspective of a long-term NFAT review, is the failure to explicitly consider scenarios that result in much higher or quicker developing future industrial load.”*³⁷

Manitoba Hydro acknowledges that it is more difficult to forecast load growth in the Top Consumers sector than it is in the Residential Basic or General Service - Mass Market sectors, where load typically increases (or decreases) gradually. Load growth (or contraction) in the Top Consumers sector, on the other hand, tends not to be gradual or linear because the addition of new customers or customer expansions can add large blocks of load and contractions or plant closings can reduce load significantly. Manitoba Hydro maintains that the PLIL calculation is a reasonable proxy for longer-term load growth forecasts based on average load growth over the past 20 years with the expectation of future periods of economic downturn and economic growth.³⁸

Forecasting Methods

Manitoba Hydro uses a hybrid approach to forecasting load, employing different methodologies for the different sectors. CAC expert, Dr. Gotham, provided the Panel with a high-level description of load forecasting methodologies that MISO considers acceptable in some circumstances and unacceptable in other circumstances. He noted that econometric modelling would be useful in a number of sectors.³⁹ Dr. Gotham identified concerns with some of the methodologies employed by Manitoba Hydro. According to Dr. Gotham, load forecasts prepared in support of generation planning for MISO participants may not utilize certain approaches, such as trend analysis or survey-based forecasting techniques. Manitoba Hydro uses both in certain elements of its load

³⁵ Exhibit ERA-5, p. 16.

³⁶ Exhibit ERA-5, p. 25.

³⁷ Exhibit MIPUG-9, pp. 3-11.

³⁸ Exhibit MH-85, p.18.

³⁹ Transcript, pp. 8292-8293.

forecasting.⁴⁰ PLIL is an example of trend analysis, as is the use of a fixed ratio of population to households, which is used in the Residential Basic forecast. The Residential Basic forecast also makes use of survey-based techniques to forecast the market share of electric heat. As the General Service – Mass Market forecast relies on the Residential Basic customer forecast, it too relies on trend analysis forecasting techniques, according to Dr. Gotham.⁴¹ Manitoba Hydro acknowledged that the PLIL calculation is a form of trend analysis, but argued that it has very little overall influence on the load forecast.⁴²

Electricity Demand/Price Elasticity

Manitoba Hydro's load forecast does not factor in the effects of increasing electricity prices on electricity demand, a concept known as price elasticity. Drs. Simpson and Gotham described its absence as "the most disturbing omission from Manitoba Hydro's forecasting methodology" because it implies an upward bias into the forecast, leading to "inflated load forecasts and requirements for new system capacity."⁴³

In a similar vein, Elenchus maintains that it is inconsistent with experience in other jurisdictions to assume there will be no impact on demand from rising electricity rates.⁴⁴ Given projected long-term annual rate increases associated with the Preferred Development Plan in the order of 2% more than expected annual increases in the Consumer Price Index, Dr. Simpson suggested that, with a long-run elasticity factor of -0.5 in the residential sector, loads could decline despite future population growth.⁴⁵ The reduced load growth could defer the need for new resources by one year and possibly up to three or four years if the General Service - Mass Market and Top Consumers sectors similarly responded to increasing electricity prices.⁴⁶

Manitoba Hydro pointed out that electricity prices in Manitoba have increased slowly, at or close to the rate of inflation and, consequently, the effect of price changes on customers' use of electricity would not have demonstrated a measurable price elasticity.⁴⁷ Manitoba Hydro provided preliminary projections of price elasticity-related load reductions in the order of 500-600 GWh by 2027/28, which are expected to be incorporated into the 2014 Load Forecast.⁴⁸ Manitoba Hydro's calculation assumes an

⁴⁰ Exhibit CAC-65, p. 4, 6; Transcript, pp. 8542-8543.

⁴¹ Transcript, p. 8641.

⁴² Transcript, p. 8543.

⁴³ Exhibit CAC-25, p. 10.

⁴⁴ Exhibit ERA-5, p. 46.

⁴⁵ Exhibit CAC-65, p. 19.

⁴⁶ Exhibit CAC-25, pp. 8-9; Transcript, pp. 8304-8305.

⁴⁷ Exhibit MH-85, p. 19.

⁴⁸ Exhibit MH-87, p.12.

elasticity value of -0.05, which Dr. Gotham described as being on the low end of values used in other jurisdictions.⁴⁹

Accuracy of Forecasts

Elenchus examined the accuracy of Manitoba Hydro's forecasts by looking at historical 5-year ahead, 10-year ahead and 15-year ahead forecast performance for both energy and peak demand. Elenchus' analysis revealed periods of under- and over-forecasting, much of which is attributable to forecasts in the Top Consumers sector,⁵⁰ while the 20-year ahead forecast accuracy levels compared favourably with some other longer-term forecasts in other jurisdictions prepared for system expansion purposes.⁵¹

As for the probability approach adopted by Manitoba Hydro, Elenchus argues that it: *"is less transparent and provides less insight than the multiple scenarios approach used in 2009."*⁵² Furthermore, according to Elenchus, it is important to test *"the sensitivity of the forecast to changes in the economic and demographic assumptions used to derive it."*

MIPUG's expert witness, Mr. Bowman, cautioned that in the context of the NFAT analysis it is less important to achieve a high degree of accuracy in a single load forecast than it is to test a series of scenarios.⁵³

Despite the concerns raised with respect to various aspects of Manitoba Hydro's load forecasting methodologies and assumptions, overall, Elenchus and MIPUG's expert found Manitoba Hydro's methodology appropriate for short-term forecasting and the load forecast reasonable.

4.4.0 Need for New Resources

The need for new generation resources arises when Manitoba Hydro expects to have a shortfall in energy or capacity. Manitoba Hydro's generation planning involves comparing the existing and proposed generating resources along with contracted and proposed imports against the firm domestic load and export obligations. The planning criteria for hydraulically generated energy are based on dependable generation, which means the generation available from the lowest water flow year recorded. The year when new resources, such as Keeyask or a gas turbine plant, are required is called the "need date", and it could be driven by either a shortfall in energy or capacity.

⁴⁹ Exhibit GAC-65, p. 34.

⁵⁰ Exhibit ERA-3, pp. 34-38.

⁵¹ Exhibit ERA-3, p. 40.

⁵² Transcript, p. 4841.

⁵³ Exhibit ERA-3; Exhibit MIPUG-9, p. 3.11.

The need date considers only the forecasted domestic load and existing export contracts. The need date does not include any future export obligations, such as the Minnesota Power 250 MW contract, except those that are already being served.

Manitoba Hydro presented several load growth scenarios to determine the domestic need date based on various levels of DSM and whether or not the pipeline load materializes.

Table 4 Need for New Resources Under Different Planning Assumptions

Estimated Need for New Resources		
Planning Assumptions	Need for Dependable Energy	Need for Capacity
2012 Planning Assumption	2022/23	2025/26
2013 Planning Assumption	2023/24	2026/27
NFAT DSM 1	2028/29	2030/31
NFAT DSM 2	2031/32	2031/32
NFAT DSM 2 + increased pipeline load	2024/25	2030/31
NFAT DSM 3	2033/34	2033/34
NFAT DSM 3 + increased pipeline load	2029/30	2030/31

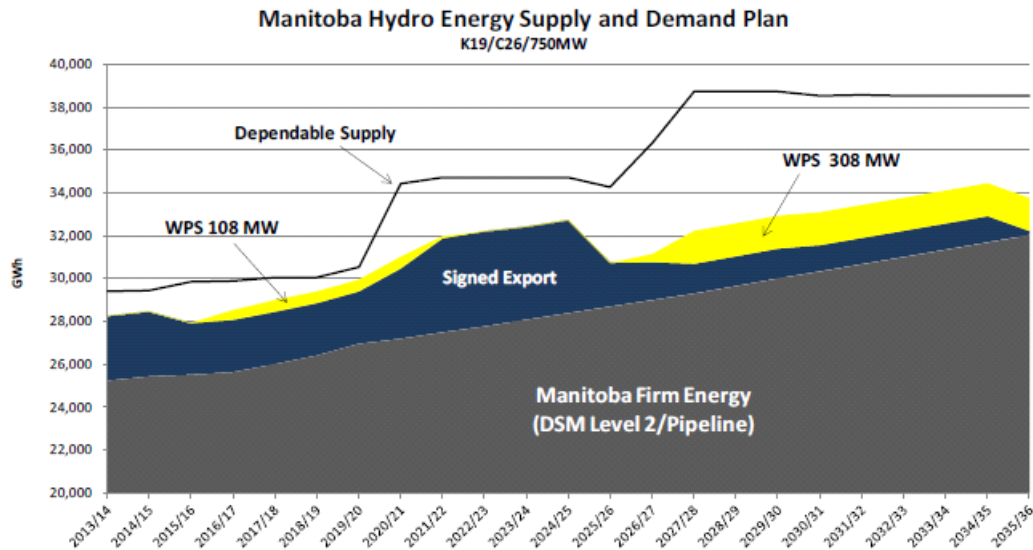
The most plausible scenario draws on their 2013 Load Forecast, includes the pipeline load and DSM Level 2 initiatives, and assumes no new exports. Initially, Manitoba Hydro stated the domestic need date was 2027, neglecting a small (39 GWh) energy deficit in 2024 because of larger energy surpluses in 2025 and 2026. Later in the NFAT proceeding, Manitoba Hydro determined the domestic need date should be driven by the small deficit in 2024, and confirmed 2024 as the domestic need date.

In all cases with additional future export obligations, such as the Minnesota Power 250 MW contract, it is assumed that Keeyask is constructed for an in-service date of 2019. However, a scenario not considered by Manitoba Hydro but investigated by the Panel is the potential to defer Keeyask while still serving the Minnesota Power and other new export contracts. This potential to defer Keeyask arose with the additional DSM savings proposed by Manitoba Hydro, resulting in sufficient surplus power to serve the new export contracts with Manitoba Hydro's existing generating resources. With DSM Level 2, or with the DSM savings from the 2014 Power Smart Plan, Keeyask may not be needed until the mid- to late 2020s.

The exact date when Keeyask is needed depends on whether the pipeline load materializes, whether Manitoba Hydro extends its diversity exchange contract with Northern States Power, or whether other measures that increase capacity are included,

such as the Curtailable Rate Program. The following Figure shows Manitoba Hydro's energy supply and demand, as well as surplus dependable energy.

Figure 2 Manitoba Hydro Energy Supply and Demand (K19/C26/750MW – Pipeline Load)



4.5.0 Transformative Change in Load Demand

4.5.1. Structural Changes to Forecast Fundamentals

The Panel heard evidence on two factors that over the longer term may have a significant impact on electricity demand: change in the fundamental factors underlying electricity demand, and distributed generation technologies achieving cost parity with grid-supplied electricity, otherwise known as “grid parity.”

Elenchus contends that Manitoba Hydro's load forecasting methodology tacitly assumes that there will be no significant structural changes in the fundamentals underpinning the forecasts. Given that the analyses on which Manitoba Hydro's NFAT Submission is based extend out over a 78-year timeframe, Elenchus maintains *“that it is more reasonable to expect that there will be significant structural changes that will result in dramatically different domestic demand (and presumably export prices) in the coming decades than it is to assume that the past provides a realistic window on the future.”*⁵⁴

Elenchus offered two examples of transformative changes to illustrate the possible impacts. Improved battery storage for electric vehicles, which, combined with carbon pricing of transportation fuels, could transform the transportation market and increase

⁵⁴ Exhibit ERA-5, p. 41.

load dramatically. On the other hand, significant penetration of alternative distributed generation technologies, such as solar photovoltaic, could transform the market and reduce load as the cost of electricity from these technologies approaches parity with grid-supplied power.

4.5.2. Impact of Grid Parity

The Panel heard evidence from witnesses about the impact of grid parity on demand for grid-supplied electricity. Grid parity is the term used to describe the point at which the cost of producing electricity with a new technology, such as solar photovoltaic or distributed generation, equals the cost of electricity from traditional generating technologies used to provide grid-based power.

Dunsky Energy Consulting's pre-filed expert evidence on behalf of CAC and GAC, noted that the cost to produce electricity from solar panels, on a ¢/kWh basis, is now the same or cheaper than electricity rates in some U.S. states and could reach parity with Manitoba Hydro's domestic rates before the end of the current load forecast period. Furthermore, the cost of utility-scale solar photovoltaic applications is declining to the point where it will become competitive with the cost of other generating technologies.⁵⁵

Grid parity has the potential to affect Manitoba Hydro in two ways: by reducing domestic demand for electricity; and by decreasing demand and suppressing prices in Manitoba Hydro's export markets. Manitoba Hydro advised that it has not carried out any modelling of the longer-term impact of grid parity or disruptive technologies on domestic load or analysed when parity will be reached in Manitoba, although it has done a high-level examination of solar photovoltaic technology as a DSM savings.⁵⁶

If grid parity materializes in the export markets, it could depress load growth and put downward pressure on prices. Manitoba Hydro may not be able to realize the export revenues it is forecasting if this were to occur.

Elenchus noted that with grid parity, distributed generation will compete directly with grid-supplied power and constrain the prices Manitoba Hydro can charge. In this scenario, Manitoba Hydro will always be able to sell the full output of its dams, but not necessarily at a sufficiently high price to recover the cost to build them: *"Once built, high-capital-cost, low-operating-cost technologies such as large-scale hydro generation which the associated extensive transmission and distribution networks may always be*

⁵⁵ Exhibit CAC-62, p. 37.

⁵⁶ Transcript, p. 604.

able to under-price the alternatives, but that ability to compete does not ensure full recovery of sunk costs.”⁵⁷

Manitoba Hydro submitted that there is a great deal of uncertainty about the timeframe when grid parity may be reached, although it does not expect sufficient penetration of distributed generation, and specifically solar photovoltaic generation, to result in any significant demand savings until after 2020.⁵⁸ Manitoba Hydro anticipates that even after grid parity is achieved, there would be a gradual reduction in domestic load over a number of years rather than a step change in load because the adoption of new technology will be slow at first and build momentum over time.⁵⁹

4.6.0 Reliability and Security of Manitoba's Electricity Supply

One of Manitoba Hydro's key responsibilities is to provide and maintain a reliable power system. Given this responsibility, Manitoba Hydro identified a need for new resources to meet persistent shortfalls in system capacity and energy and identified different development plans to meet that need. When considering reliability, the focus is on the ability of the power system to meet peak load. Manitoba Hydro designed the Preferred Development Plan and alternative plans evaluated for the purpose of its NFAT Submission to provide the required system reliability and to ensure that there are sufficient resources to meet peak and annual load.

Manitoba Hydro explained to the Panel that the degree of system reliability is typically measured by “loss of load expectation” – the average number of days per year that the load could not be fully met. A common industry standard is an inability to meet system load one day every 10 years. The lower the loss of load expectation, the greater is the system's reliability. This can equivalently be expressed in terms of the system's load-carrying capability. With greater reliability, the system can reliably carry or meet a greater amount of peak load.

Although all of the development plans that Manitoba Hydro considered ensure system reliability, some plans were found to offer more reliability than others. Plans with a 750 MW interconnection provide greater reliability because of the ability to import power from the U.S. For example, plans with a 750 MW transmission interconnection offer 500 to 1,000 MW of additional transmission capacity to carry domestic load from 2020 to 2040 than plans with no interconnection, and the Preferred Development Plan, with its

⁵⁷ ERA-3 p. 42.

⁵⁸ Transcript, p. 606.

⁵⁹ Transcript, p. 607.

two generating stations and the 750 MW transmission interconnection, offers the most reliability benefits of the plans with a 750 MW interconnection.⁶⁰

Building Keeyask would add more capacity than is required for a considerable period of time and Conawapa would add even more. This additional capacity is far more than reliability-planning metrics suggest is needed. However, there are reliability benefits associated with these additions in terms of avoiding shorter- and longer-term power outages and supply constraints.

Manitoba Hydro's analysis indicates that development plans with a 750 MW interconnection are much more secure under extreme drought conditions than other plans because of the import room they provide – some 3,000 to 4,500 GWh/year more emergency energy for Manitoba domestic load from 2020 to 2040.⁶¹ Although the Preferred Development Plan adds additional hydraulic generation that can be affected by drought, it will still add to Manitoba's energy security because Manitoba Hydro can curtail delivery of exports in order to satisfy Manitoba load.

4.7.0 Conclusions of the Panel

The Panel is satisfied that Manitoba Hydro's load forecast is reasonable for the short term. It is prudent to assume that the planned pipeline load will materialize, especially in light of the long lead time to construct Keeyask and Manitoba Hydro's obligation to serve domestic load. The Panel accepts the need date determined by Manitoba Hydro to be 2024, based on the 2013 Load Forecast, DSM Level 2, and the pipeline load.

Nonetheless, the methodological concerns raised by parties to the NFAT Review highlight the need for more robust forecasting. In future General Rate Applications, the Panel will expect Manitoba Hydro to provide a more robust forecast to better understand the factors that influence short-term load fluctuations.

That said, the Panel encourages Manitoba Hydro to consider the improvements to the load forecasting methodology recommended by Drs. Gotham and Simpson, as they could provide benefits to the forecasts considered at future rate proceedings.

The Panel has less confidence in Manitoba Hydro's forecast in the long term as it does not address the effects of potential structural change from new technologies or grid parity. The Panel recognizes that such factors are difficult to predict in both their magnitude and direction. While some structural change, such as the widespread adoption of electric vehicles, could significantly increase demand, other structural

⁶⁰ Exhibit MH-204, p.182

⁶¹ Exhibit MH-95, p. 140.

change, such as grid parity for solar photovoltaic technology, could substantially decrease it. It is the Panel's view that Manitoba Hydro should, in the coming years, avail itself of external expertise to be a leader in the implementation of these technologies and prepare future integrated resource plans on that basis.

In light of the significant rate increases projected over the next 20 years, the Panel further concludes that Manitoba Hydro should more carefully scrutinize the potential for price elasticity impacts.

The Panel notes that Demand Side Management initiatives in the future will likely have a profound impact on Manitoba Hydro's load forecast. This issue is further discussed in Chapter 5. Manitoba Hydro did not consider the ability for DSM to increase Manitoba Hydro's exportable surplus, such that Keeyask may not be needed to serve the new export contracts until the mid- to late 2020s. The Panel views this as a weakness in the analysis. Despite this shortcoming, the Panel accepts that there are tangible reasons to proceed with the construction of Keeyask at this time, rather than to delay construction for five years and require a renegotiation of the general civil contract to construct the project and the numerous First Nation agreements already executed.

Should Manitoba Hydro's load forecast turn out to be too low, construction of the 750 MW U.S. transmission interconnection provides concrete reliability benefits, as it facilitates additional imports.

5.0.0 Demand Side Management (DSM)

5.1.0 Introduction

The Terms of Reference direct the Panel to consider the role of Manitoba Hydro's Demand Side Management (DSM) and conservation forecasts in Manitoba Hydro's Preferred Development Plan. This involves consideration of whether the DSM programs were adequately integrated into Manitoba Hydro's resource planning, and assessing the extent to which DSM could affect decisions on the timing of and need for new resources. For the purposes of this chapter, DSM includes energy efficiency and capacity savings.

The Panel heard of the importance of DSM in the course of the NFAT Review hearings. DSM can be a valuable and versatile asset in resource planning. It can help meet energy, as well as capacity needs. It can be targeted to specific end-users or technologies and solutions, and designed to meet the challenges and circumstances of each jurisdiction. DSM can be designed to offset or delay the need for new generation investments. Philippe Dunskey, an expert witness appearing on behalf of CAC, put forward the business case for DSM as a resource option, noting that at 2¢ to 4¢ per kWh, DSM costs two to eight times less than new power plant investments, produces from two to ten times more jobs per million dollars invested, reduces greenhouse gas (GHG) emissions, has economic benefits, and produces high levels of customer satisfaction.⁶²

During the hearings, a significant change in DSM planning and strategy occurred. In early March 2014, Manitoba Hydro introduced the possibility of including a new set of DSM programs and measures in the Preferred Development Plan and the alternative development plans. Their effect would be to potentially delay the need for new generation resources and deal with increasing domestic need. Up to this point, Independent Expert Consultants and Interveners had been critical of the Preferred Development Plan and the absence of new DSM plans or efforts. This changed with Manitoba Hydro's new DSM plan, which promised an impact on the need for new resources and the nature of the required resource portfolio.

In its NFAT Submission in August 2013, Manitoba Hydro provided a DSM potential study prepared by EnerNOC, a U.S. consulting firm that identified the DSM potential that could be achieved. Manitoba Hydro retained EnerNOC in 2011.⁶³ Relying on EnerNOC's work, Manitoba Hydro developed three different levels of DSM savings,

⁶² Exhibit CAC-62, p.9.

⁶³ Transcript, p.395.

identified as Level 1, Level 2, and Level 3, and concluded that DSM Level 2 was achievable and economic. Manitoba Hydro first provided this information in late February 2014. Manitoba Hydro then provided a number of economic analyses based on the assumption that DSM Level 2 would be implemented.

This Chapter focuses on the nature and impact of these new DSM Level 2 initiatives, their associated energy and capacity savings, their impact on the Preferred Development Plan and alternative development plans, and the requirements to ensure the successful implementation and long-term realization of DSM goals.

5.2.0 Manitoba Hydro's Power Smart Programs and DSM Proposal

5.2.1. Manitoba Hydro's Power Smart Programs

Manitoba Hydro engages in DSM initiatives to reduce electricity demand. Manitoba Hydro's DSM programs are outlined in its Power Smart Plans, and consist of energy conservation and load management activities designed to lower the demand for both electricity and natural gas in Manitoba. Program measures include:

- Education initiatives and financial incentives to encourage energy savings;
- Supporting energy savings through the adoption of federal and provincial codes and standards;
- Load reduction by participating customers; and
- Encouraging customers to install load-displacement generation systems.

Manitoba Hydro views DSM programs as a way to reduce energy consumption and demand, and thus defer the need for new generating resources. Manitoba Hydro used to be a leader in DSM. In recent years, Manitoba Hydro's DSM spending has decreased. The energy savings reported by Manitoba Hydro on an annual basis as a percentage of total demand have declined to approximately 0.4%, well below the 1.5% to 2% levels achieved in many other jurisdictions.

Manitoba Hydro's 2013-2016 Power Smart Plan outlined a series of measures that Manitoba Hydro expected would produce energy savings of 570 GWh and demand reductions in the order of 280 MW over the Plan's three-year horizon. The three-year plan was prepared in consultation with the Government of Manitoba, as required under *The Energy Savings Act*.⁶⁴ Manitoba Hydro was forecasting that the DSM efforts in its

⁶⁴ Transcript, p. 9856.

2013-2016 Power Smart Plan would reduce annual load growth to 1.4% per year over the 20-year load forecast period.

Manitoba Hydro's new 2014-2017 Power Smart Plan, which became available in April 2014 during the NFAT Review hearings, outlines substantially increased spending on DSM and proposes a doubling of targeted electricity savings to be achieved over the next three years (2014/15-2016/17) relative to the 2013-2016 Power Smart Plan. These savings are projected to be 1064 GWh and 411 MW, or 4% of the estimated load forecast by 2016/17, thus offsetting 86% of projected load growth during this three-year period.⁶⁵ Manitoba Hydro prepared its 15-year Supplemental Report for integrated resource planning purposes.

5.2.2. Revised Manitoba Hydro DSM Proposals (March 2014)

Before the NFAT Review hearings began in early March, Manitoba Hydro filed new evidence on its DSM activities and projections, which Manitoba Hydro described as DSM Levels 1 through 3. Each level contains higher levels of DSM programming, as described below, and produces progressively higher levels of energy savings beyond the existing DSM portfolio used in the NFAT Submission.⁶⁶

- DSM Level 1 is comprised of energy efficiency initiatives, which include extending some existing programs, technologies such as LED lights for applications in roadway, residential and commercial lighting, and modifying some existing programs with a more aggressive design and approach.
- DSM Level 2 includes the Level 1 initiatives plus measures such as conservation rates, load displacement measures, and fuel switching.
- DSM Level 3 encompasses all of the DSM Level 2 initiatives and modifies the energy efficiency programs to achieve greater energy savings, but at a higher cost. These higher cost programs would be considered uneconomic relative to the Level 2 programs when evaluated against the marginal costs but were included to test more fully the viability of a higher level of DSM.⁶⁷

The three new programs Manitoba Hydro highlighted as part of DSM Level 2 were conservation rates, fuel switching, and load displacement. Conservation rates are electricity rates that are tailored to encourage conservation through pricing mechanisms and may involve inclining blocks where electricity consumed beyond a certain threshold costs more than the initial block. These rates would require approval by the Public

⁶⁵ Exhibit MH-153, p. 1.

⁶⁶ Exhibit MH-85, pp. 28-29.

⁶⁷ Exhibit MH- 85, p. 28.

Utilities Board. Fuel switching encourages customers to use natural gas instead of electricity for space and water heating. Load displacement programs encourage industrial customers to self-generate electricity.

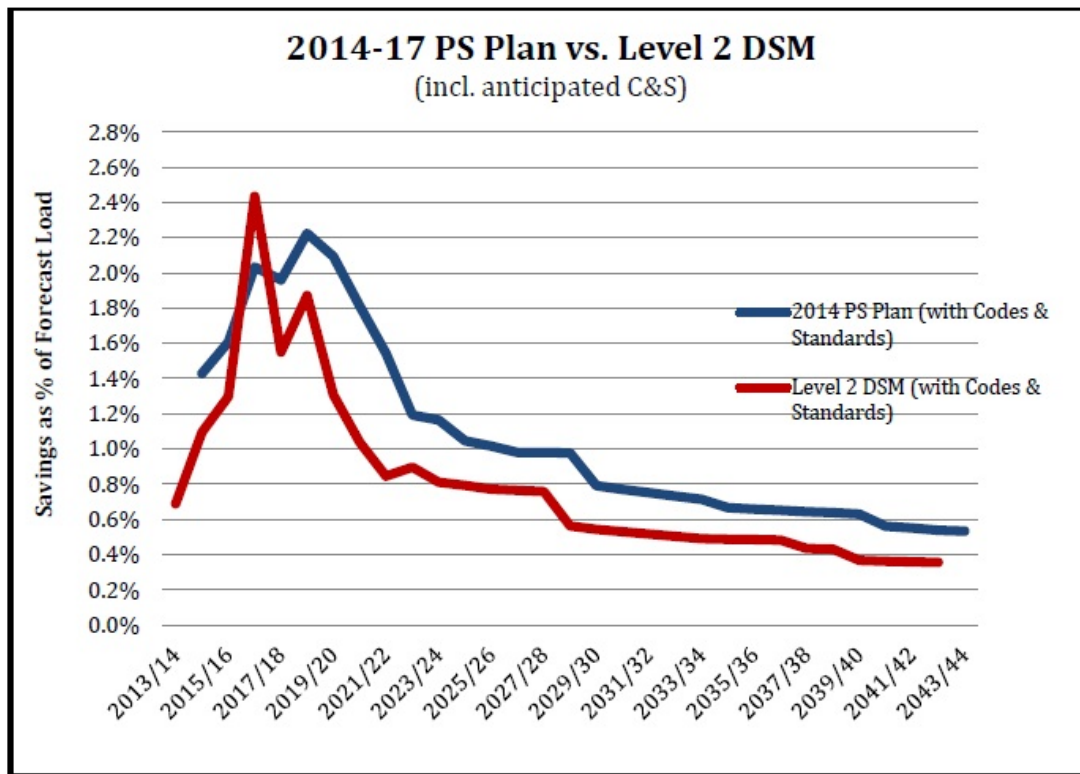
These increased levels of DSM represent substantial increases over the DSM program outlined in the 2013 Power Smart Plan; ranging from 2.2 to 4.6 times the program savings outlined in the 2013 Plan.⁶⁸ Manitoba Hydro considered the DSM Level 2 initiatives to be economic, but Level 3 to be uneconomic.

Manitoba Hydro confirmed that the DSM savings projected in the 2014-17 Power Smart Plan were similar to the savings projected for DSM Level 2. The Power Smart Plan program savings are slightly lower than the DSM Level 2 savings. However, the savings from codes and standards projected in the Power Smart Plan are higher, making the overall Power Smart Plan savings greater than DSM Level 2.

In assessing DSM savings, a distinction must be drawn between cumulative savings and incremental savings. Once a DSM measure is implemented, it usually provides cumulative savings. Incremental savings, on the other hand, are those savings achieved through new measures layered on top of existing measures. The Figure below illustrates the anticipated differences between the 2014-2017 Power Smart Plan and DSM Level 2 in terms of incremental DSM savings, expressed as a percentage of forecasted load, including codes and standards savings.⁶⁹

⁶⁸ Exhibit MH-204, p. 20.

⁶⁹ Exhibit MH-202.

Figure 3 Manitoba Hydro 2014 Power Smart Plan vs. DSM Level 2 Savings

5.3.0 The Impact of New DSM on Load Growth

A number of witnesses talked about the impact of Manitoba Hydro's DSM Level 2 proposals on the forecasted load growth. All agreed that increased DSM could reduce load growth. Most suggested that with successful implementation, Manitoba Hydro could achieve DSM savings greater than Manitoba Hydro's plans, which they characterized as conservative in the long term.

Several witnesses questioned the proposed incremental savings scenario for DSM Level 2, particularly the sudden increase followed by a tailing-off of incremental savings. As illustrated in the above Figure, Manitoba Hydro's scenario suggests a rapid increase in incremental savings to 2.4% in 2017/18, followed by an equally steep decline to 0.8% in 2021/22, and then a downward trend to 0.4% by 2043/44. Mr. Chernick, who testified on behalf of the Green Action Centre, suggested that it was unusual for a power utility to commit to an early DSM increase and then indicate that there were few achievable DSM savings afterwards.⁷⁰ He stated:

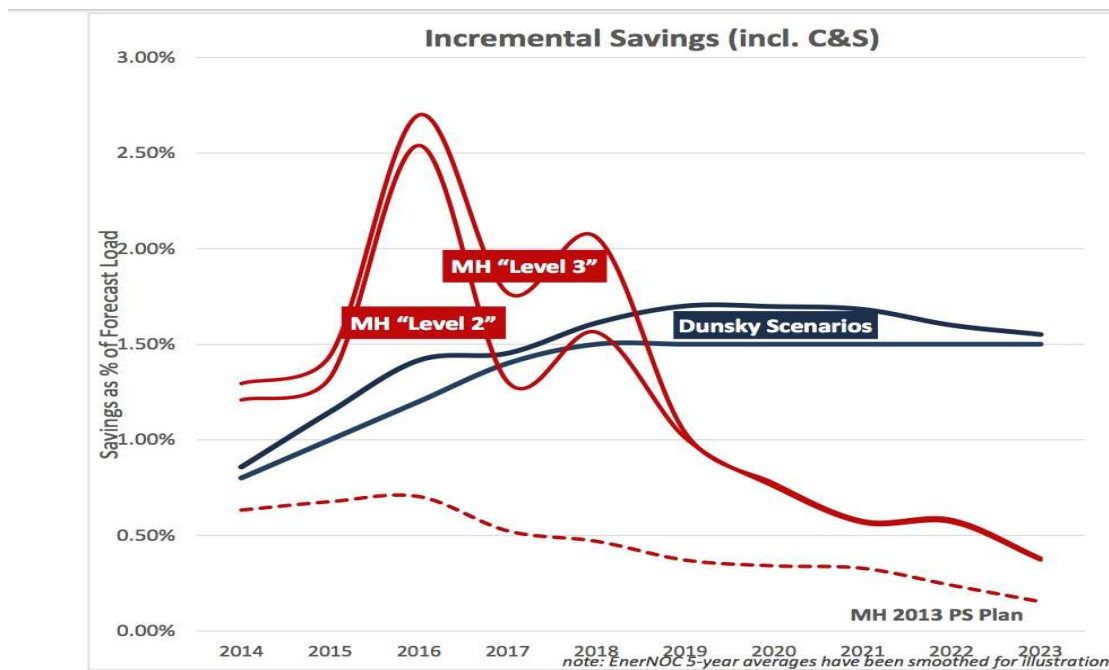
⁷⁰ Transcript, p. 9838.

I can't really think of another example that – that's quite so vivid in terms of a utility saying over and over again, we can do a lot in the next few years, but then nothing after that. And it – it looks like the Utility is – is willing and interested in doing some energy efficiency in the near term, but is reluctant to interfere with long-term construction plans by committing to a long-term energy efficiency program, so the numbers go down.⁷¹

Mr. Dunskey submitted that Manitoba Hydro's DSM Level 2 plans represented a static view of the future: while they signified a dramatic and commendable change in DSM planning and target setting over the short term, they then reverted to previous assumptions, such that by 2023 and after, DSM savings would be 90% below the Level 2 peak.⁷²

Mr. Dunskey provided the Panel with an alternative view for a DSM scenario that presents a more gradual growth to 1.5% incremental savings in 2016, followed by a stable DSM savings of 1.5% around 2019, as depicted in the Figure below.⁷³

Figure 4 Incremental Savings - Manitoba Hydro DSM Levels 2 & 3 vs. Dunskey Scenarios



Mr. Dunskey felt that Manitoba Hydro could achieve annual average energy savings at a cost well below the cost of new generation or the price of power exports, and achieve

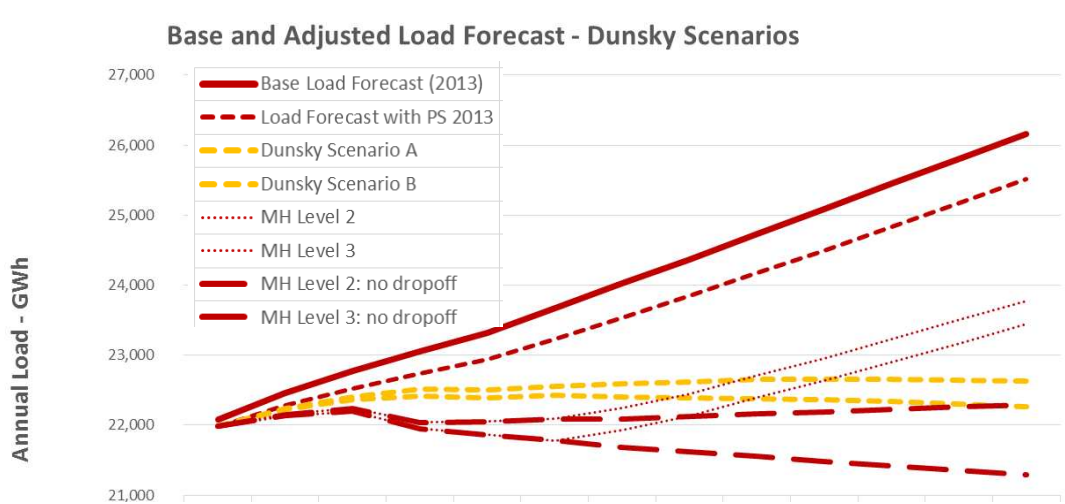
⁷¹ Transcript, p. 9838.

⁷² Exhibit CAC-62, p.15.

⁷³ Exhibit CAC-62, p.14.

annual average energy savings for the next 10 years (2014-2023) of 1.1% from utility programs (1.3% including codes and standards) under a “cautious” DSM scenario and 1.3% (1.5% including codes and standards) under a more aggressive approach to DSM.⁷⁴ These increased DSM levels, he maintained, could translate into cumulative savings over that 10-year period of 2,634 GWh/year (3,220 GWh/year including codes and standards) under the cautious scenario and 3,013 GWh/year (3,534 GWh/year including codes and standards) for the aggressive portfolio, the net effect of which is to virtually flatten domestic load growth, as shown by the dashed yellow lines in the following Figure.⁷⁵

Figure 5 DSM Scenarios' Impact on Manitoba Hydro Load Forecast



Mr. Chernick also suggested that Manitoba Hydro could increase DSM savings from the current 0.4% of retail sales to 1.5% of sales annually through a combination of measures to discourage the use of electricity for heating, as well as codes and standards, and regulations.⁷⁶

A number of witnesses were of the view that it was possible to flatten load growth with DSM. Dr. Gotham, an expert witness on behalf of the CAC, felt that DSM could not realistically achieve negative net load growth, because incentives change when load is shrinking there is no longer the benefit of avoided cost of new generation.⁷⁷ Mr. Dunskey argued that load growth could be flattened and new generation deferred until at least

⁷⁴ Exhibit, CAC-62, p.13.

⁷⁵ Exhibit CAC-19, p. 30; Transcript p.7876.

⁷⁶ Exhibit GAC-22, p. 25.

⁷⁷ Transcript, pp 8602-8603.

the mid-2020s.⁷⁸ Mr. Chernick and another CAC expert, Dr. Higgin, also agreed that flat load growth could be attained through DSM efforts.⁷⁹

The original versions of Manitoba Hydro's proposed development plans provided in August 2013 assumed the 2012 load forecast projections, and a "base" level of DSM. The 2014 versions of the development plans assume the newer 2013 load forecast projections and substantially higher DSM spending to achieve DSM Level 2. This change in forecasted DSM savings caused dramatic changes in both the need date for new generation resources to meet Manitoba demand and in the economics of the development plans that Manitoba Hydro analyzed.

DSM Level 2 affected the Net Present Value of all development plans. The Net Present Value of the Preferred Development Plan relative to the All Gas Plan decreased by \$329 million such that it is only \$45 million better than the All Gas Plan. Plans with Keeyask but not Conawapa were not significantly affected by DSM Level 2 relative to All Gas, and, in fact, improved their Net Present Value.⁸⁰

Chapter 8 of this Report discusses Manitoba Hydro's economic evaluation of the Preferred Development Plan and alternatives.

5.4.0 The Value Proposition of DSM

During the NFAT Review hearings, the Panel heard from a number of witnesses about the importance of DSM in Manitoba's energy future. Witnesses spoke to the Panel about successful DSM programs in other jurisdictions and the framework required to achieve stable long-term DSM savings. The Panel saw that DSM can have a profound impact on the date when new energy resources are needed. The Panel learned that DSM is a powerful resource that can bring value to resource planners, ratepayers, the economy, and the environment. The Panel, therefore, considered how DSM can bring that value. It looked at the role of DSM in resource planning.

The Panel found that treating the DSM savings from the Supplemental 2014 Power Smart Plan as a separate, independent energy resource, yields capacity savings that amount to more than 80% of the net system capacity addition from the proposed Conawapa Project. Similarly, the annual dependable energy savings from the Power Smart Plan exceed 85% of the dependable energy output from the proposed Conawapa

⁷⁸ Transcript, p.8182; Exhibit CAC-62, p. 57.

⁷⁹ Transcript, p.9536; Transcript, pp. 9661-2.

⁸⁰ Exhibit MH 104-15, p. 2.

Project. To achieve these electricity savings, Manitoba Hydro budgets to spend \$822 million, which is less than 8% of the \$10.7 billion cost of building Conawapa.⁸¹

5.4.1. Role of DSM in Resource Planning

A number of witnesses discussed how DSM savings should be treated for resource planning purposes.

Manitoba Hydro provided evidence on how its DSM initiatives fit into its power resource planning process. Referring to the interface as a “combined DSM integrated resource planning process”, it begins with resource planning staff indicating a value that represents the value of energy to Manitoba Hydro (currently approximately 7.5 ¢/kWh). This marginal value represents the value of energy that is saved and then exported combined with the avoided cost of new transmission and distribution infrastructure. This value is used to update Manitoba Hydro's Power Smart Plan in relation to economic DSM opportunities based on a total resource cost metric. The revised plan is then provided back to Manitoba Hydro's resource planners for input into the resource planning process.⁸²

Elenchus and Mr. Dunsky emphasized that Manitoba Hydro should treat DSM as a resource option from the outset, assessing it in the same manner as investments in traditional resource options such as hydro dams or investments in transmission and distribution. Both suggested that Manitoba Hydro pursue an Integrated Resource Planning (IRP) approach to evaluate supply- and demand-side resources on an equal footing.⁸³

Mr. Dunsky further stated that an integrated process helps to ensure that least cost options are fully considered. He maintained that by not treating DSM as a resource option through an IRP approach in its analysis of the possible resource options to meet domestic power needs, Manitoba Hydro has “*de facto excluded the single lowest-cost and lowest-risk resource option available*”⁸⁴ and “*risks locking itself into a path of new supply that, as a result, will lock out the much less expensive option of more efficient demand.*”⁸⁵

Manitoba Hydro maintains that it is undertaking integrated resource planning that combines supply and demand options, and that its Power Smart Plan is an integral

⁸¹ Exhibit MH-180, p. 31.

⁸² Transcript, pp. 431-434.

⁸³ Exhibit ERA-2.2, p. 1; Exhibit CAC-19, p. 6.

⁸⁴ Exhibit CAC-19, p. 12.

⁸⁵ Exhibit CAC-19, p. 16.

component of its resource plans. It asserted that the analysis of DSM options and supply options provided to the Panel after the hearing began was an integrated evaluation.⁸⁶

There was also discussion about innovations that can sustain DSM savings over the long term. Mr. Dunskey stressed that DSM opportunities are constantly being renewed through innovation.⁸⁷ He further suggested that Manitoba Hydro was presenting an unrealistic view of the emerging opportunities for energy efficiencies, such as emerging innovations in efficiency standards, LED lighting, heat pumps, data-driven analytics, and solar photovoltaics.⁸⁸ In his view, *“New DSM opportunities abound – including several ‘game changers’ that have already landed in market, with many more to come.”*⁸⁹ He further stated that: *“Not accounting for these game changing future opportunities really exposes long-term investment plans to significant risk. And that’s not to say it’s not a risk worth taking, but there’s a very real risk that needs to be accounted for, especially in long-term forecasts.”*⁹⁰

Mr. Dunskey indicated that resource planners in a number of jurisdictions are now assuming that DSM opportunities will continue to improve and replenish themselves as opposed to reaching depletion. Those same system planners also consider DSM to be a dependable, low-risk resource.⁹¹

Manitoba Hydro has traditionally focused on DSM measures and opportunities that are known, commercially available, or very near commercialization.⁹² On the issue of innovation and the focus of its DSM measures and opportunities, Manitoba Hydro stated the following:

*“While it may only be a question of timing as to when the next innovation or evolution of energy efficient technology will become available and commercially viable, for the purposes of resource planning and meeting customers' energy needs, timing does matter. The Corporation must balance risks and the timing of technology evolution, and its adoption can have a significant impact on the Corporation's obligation to meet customers' energy requirements.”*⁹³

⁸⁶ Exhibit MH-204, pp. 38-39.

⁸⁷ Transcript, p. 8076; Exhibit CAC-62 pp.19-39.

⁸⁸ Exhibit CAC-62, pp. 32-38.

⁸⁹ Exhibit CAC-62, p. 39.

⁹⁰ Transcript, pp. 8034-8035.

⁹¹ Exhibit CAC-62, p. 52.

⁹² Exhibit MH-204, p. 25.

⁹³ Exhibit MH-204, p. 26.

The certainty of DSM savings was the subject of some discussion. While Manitoba Hydro includes DSM in its supply-demand analysis and considers DSM to be 100% dependable, it would appear to have some reservations about the certainty of DSM as a resource. In its NFAT Submission, Manitoba Hydro notes the following:

“... Without regulation or legislation, achieving energy reduction targets is strongly dependent upon market acceptance and voluntary action. Also, in addition to market availability and adoption forecasts, the savings potential is estimated based on a variety of assumptions that include natural technological development, anticipated customer energy usage/savings and market cost projections. As a result, expected energy savings from DSM do not have the same future certainty of supply as would the development of a physical resource.”⁹⁴

Elenchus maintained that future DSM savings were not certain and suggested that DSM should be treated as a non-dispatchable resource subject to explicit dependability factors.⁹⁵ Mr. Dunskey, on the other hand, was of the opinion that all forecasted DSM savings could be counted on for planning purposes.⁹⁶ This view was supported by Mr. Chernick.⁹⁷

5.4.2. Value of DSM to Ratepayers: Savings Potential

DSM program spending and benefits have different impacts on customers as some customers participate to varying degrees in the DSM programs while other customers do not participate at all. In particular, specific barriers to participating in DSM programs have been identified with respect to lower income customers.

DSM programs typically result in higher rates because total demand is reduced; the fixed costs of Manitoba Hydro's system, including DSM spending, do not fall with demand and have to be recovered over lower sales volumes. The result is that bills may go down for participating customers even as the electricity rates may go up. Customers who access DSM programs and choose to participate can benefit from reduced energy consumption and thus reduce their annual energy bills. Customers who do not participate in DSM programs and therefore do not reduce their energy consumption will potentially pay more for their electricity.⁹⁸

⁹⁴ Manitoba Hydro NFAT Submission, Chapter 7, p. 13.

⁹⁵ Exhibit ERA-2-2, p. 35.

⁹⁶ Transcript, p. 8074.

⁹⁷ Transcript, p. 9822.

⁹⁸ Exhibit MPA-3-1, pp. 6-7.

In jurisdictions that export surplus energy and capacity, DSM savings may mitigate the rate increases associated with the cost of DSM measures. This mitigating effect comes from the ability of DSM measures to free up more energy and capacity for export, and thus increase revenues from export sales. If export prices are equal to or greater than the utility's costs of the DSM measures, these costs could be recovered from export revenues and ratepayers might not see a rate increase at all.

Residential customers can realize significant savings on their energy bills if they fully utilize the available DSM measures. Manitoba Hydro provided three example scenarios to illustrate such savings based on an average single detached home of approximately 1,300 square feet.⁹⁹ These examples show annual energy savings ranging from 7% to 42% depending on the measures employed.

- Example 1: For the customer heating both their home and their water with electricity, if they were to install energy efficient lighting, the free Water & Energy Saver kit, upgrade their attic insulation from R20 to R50 and their basement insulation from R0 to R24, and retire their second refrigerator, they could save approximately 42% on their annual electricity bill.
- Example 2: For the customer heating their home with natural gas and their water with electricity, if they were to install energy efficient lighting, the free Water & Energy Saver kit and retire their second refrigerator, they could save approximately 16% on their electricity costs or 7% on their overall energy bill (natural gas and electricity).
- Example 3: For the customer heating their home and their water with natural gas, if they were to install energy efficient lighting and retire their second refrigerator, they could save approximately 15% on their annual electricity costs or 5% on their overall energy bill (natural gas and electricity).

DSM programs are a direct way for residential, commercial, and industrial ratepayers to participate in their energy savings and contribute to their energy future. Since their implementation in 1989, Manitoba Hydro programs will have saved participating customers over \$1 billion.¹⁰⁰

Certain industrial customers have the greatest potential to benefit from DSM program energy savings as they are large consumers of electricity. The Manitoba Industrial Power Users Group (MIPUG) indicated that industry has been one of the largest and most committed participants in Manitoba Hydro's DSM programming.¹⁰¹ However, as

⁹⁹ Exhibit MH-164.

¹⁰⁰ Exhibit MH-154, p.5.

¹⁰¹ MIPUG-28, p. 91.

further set out below, MIPUG was critical of the perceived lack of availability of some DSM measures to industry, particularly the Curtailable Rate Program (CRP).¹⁰²

In its updated analysis of ratepayer costs for the Panel, Morrison Park found that DSM Level 2 had a “powerful effect” on ratepayer costs in that it brought ratepayer costs down. They noted that DSM can not only help to reduce the electricity bills of ratepayers who take advantage of the programs, but also reduce Manitoba domestic load, and free up more capacity for export.¹⁰³

5.4.3. Value to Lower Income Customers

Throughout the hearing, the Panel heard about how lower income customers would be negatively affected by the rate increases projected in Manitoba Hydro's development plans. The Panel also learned that lower income customers face barriers to participating in energy efficiency programs. CAC identified a number of barriers to lower income customer participation in Power Smart programs, including lack of access to financing, housing conditions that preclude energy efficiency improvements, and electricity bills being in arrears.¹⁰⁴ Witnesses noted the common problem of DSM programs in reaching lower income and vulnerable customers. In some cases, the challenge is getting information, services, and incentives to rural and remote communities.

Dr. Higgin stressed the importance of DSM programs reaching vulnerable customers. He concluded that bills, not rates were important.¹⁰⁵ Dr. Higgin was of the view that the impacts on ratepayer bills in the short term proposed for the Preferred Development Plan were not acceptable, particularly for vulnerable consumers,¹⁰⁶ whom he defines as customers whose household income is less than 125% of Statistics Canada's Lower Income Cut-Off measure.¹⁰⁷

The ability of customers who are in arrears to participate in Power Smart Programs was identified as a particular concern. Manitoba Hydro does not permit these customers to participate in its Power Smart programs unless they have made payment arrangements designed to eliminate the arrears. The Panel was told that the exclusion of customers in arrears from Power Smart programs has a significant impact on many aboriginal communities where many residents are in arrears.¹⁰⁸ MKO submitted in its closing

¹⁰² Exhibit MIPUG-28, p. 91.

¹⁰³ Exhibit MPA-3-1, p. 14.

¹⁰⁴ Exhibit CAC-92 p. 63; Transcript p.11139.

¹⁰⁵ Exhibit CAC-76, p. 10; Transcript, p. 9458.

¹⁰⁶ Exhibit CAC-76, p. 10.

¹⁰⁷ Transcript, p. 9450.

¹⁰⁸ Exhibit MKO-11. p. 8.

argument that 86% of MKO First Nations accounts are currently in arrears and are therefore ineligible to participate in DSM measures.¹⁰⁹

The Interveners agreed that specific actions should be taken to assist lower income and vulnerable customers. CAC suggested that bill support be considered.¹¹⁰ MKO stressed the importance of Manitoba Hydro undertaking efforts to reduce electricity bills by ensuring the availability of DSM programs, particularly to lower income, fixed income, and remote residential customers, and to general service customers in First Nations communities. MKO also maintained that future rate increases should be conditional on Manitoba Hydro's DSM programs being universally available and practically accessible to First Nations customers. To achieve accessibility, MKO recommended that Manitoba Hydro act on Mr. Dunsky's ideas of providing DSM programs on a turn-key basis to First Nations customers. MKO also recommended that Manitoba Hydro measure and report on the availability and penetration of lower income DSM programs for First Nations customers, particularly to lower income First Nations customers, and on the success of DSM programs in reducing the bills of lower income First Nations customers.¹¹¹

5.4.4. The Curtailable Rate Program (CRP)

Manitoba Hydro has had a Curtailable Rate Program in place for industrial customers since 1998. Customers who participate in the Curtailable Rate Program can have their power curtailed on short notice. This program is used to maintain operating and contingency reserves in order to minimize disruption to Manitoba Hydro's firm customers in the event of loss of generation or transmission. Curtailable load is particularly valuable to Manitoba Hydro in system emergencies. However, its greatest value is during times of peak power use.

Mr. Dunsky explained that there is considerable opportunity for Manitoba Hydro to achieve capacity savings through a combination of new demand response initiatives, energy-focused DSM initiatives, and Manitoba Hydro's current industrial Curtailable Rate Program (CRP).¹¹² The Panel learned that Manitoba Hydro has capped the CRP and is no longer accepting new entrants. MIPUG members appeared before the Panel and expressed an appetite for continued participation in the program, as well as for enhanced and new opportunities to participate in other demand response initiatives and customer self-generation measures. MIPUG offered the view that Manitoba Hydro had not captured the benefits of the CRP. In its view, the CRP provides capacity and helps

¹⁰⁹ Exhibit MKO-11, p. 8.

¹¹⁰ Exhibit CAC – 91, p. 50.

¹¹¹ Exhibit MKO-11, pp. 6-7.

¹¹² Exhibit CAC-19, pp. 41-42.

with reliability. As such, participation in the CRP should not be capped and there should be options to allow for new participants.¹¹³

In response, Manitoba Hydro noted that only 16 industrial customers have made use of the CRP since its formation, and only three businesses currently use it. Accordingly, while Manitoba intends to ensure that existing CRP participants continue to receive its benefits, Manitoba Hydro indicated that to remove the cap would invite uneconomic DSM.¹¹⁴

5.4.5. DSM and Fuel Switching

GAC's expert witness, Mr. Chernick, raised a concern with the ongoing switching of Manitoba Hydro customers from gas-fired space and water heating to electric heat. In GAC's view, space and water heating with natural gas is preferable by every measure. Gas heating is a more efficient use of gas than to generate power (greater than 90% efficient for space heating versus 25 to 50% efficient in a power plant), saves customers money, is better for the environment because of reduced global emissions, and provides cash flow to Manitoba Hydro through additional exports. Since the electricity savings generated by relying on gas allow Manitoba Hydro to export more electricity into the heavily coal-based MISO market, relying on gas heat instead of electric heat actually reduces global greenhouse gas emissions. In light of these factors, GAC called the ongoing switch to electric space and water heat a "*serious market failure*."¹¹⁵

Manitoba Hydro's 2012 Fuel Switching Report provided findings similar to Mr. Chernick's analysis. The Report states that: "*From the customer, utility and provincial leakage perspectives, there are substantive benefits when customers use natural gas rather than electricity for space heating purposes... Using electricity for space heating in Manitoba as opposed to natural gas will reduce GHG emissions in Manitoba; however the global GHG emissions will be higher due to reduced electricity exports from Manitoba.*"¹¹⁶

Manitoba Hydro owns Centra Gas, the Province's only natural gas distributor. Because of this, Manitoba Hydro is in the position of being able to encourage its customers' fuel choices one way or the other. Rather than aggressively advocating one fuel over the other, Manitoba Hydro has developed a "Fuel Switching Initiative" consisting of an education and information campaign directed to homeowners, heating contractors, homebuilders, and land developers. The aim of the initiative is to increase awareness of

¹¹³ Exhibit MIPUG-28, p. 68.

¹¹⁴ Exhibit MH-204, p. 35.

¹¹⁵ Exhibit GAC-27, pp. 12-13.

¹¹⁶ Manitoba Hydro NFAT Submission, Appendix 15.4.

the lifetime costs of installing and operating electricity, natural gas, and geothermal heating systems in order to provide customers with information to make informed choices.

Mr. Chernick disagrees with this passive approach and suggests that the trend toward electric heat could be reversed through the vigorous promotion of gas heat by a combination of better information, appropriate incentives, Power Smart programs, and offering low-cost, on-bill, transferable financing.¹¹⁷ Furthermore, Mr. Chernick suggested that Manitoba Hydro could do more to discourage electric heat by increasing the cost to land developers for electricity line extensions and reducing the cost of gas connections.¹¹⁸ Elenchus further noted that because Manitoba Hydro controls both the distribution and sale of electricity and natural gas, and Manitoba Hydro's focus as a Crown corporation is on serving the customer as cost effectively as possible, it should help customers choose the least expensive fuel.¹¹⁹

The Manitoba Métis Federation noted its concern about the failure of Manitoba Hydro to consider biomass, such as wood, as a fuel switching or load displacement option. They observed that many northern and aboriginal communities have access to this fuel source and that considerable new technologies now exist to use biomass as a fuel.¹²⁰

5.4.6. DSM Employment Potential

Manitoba Hydro indicated that it did not prepare a study of the employment impacts associated with DSM for the NFAT Review, in part, because fewer opportunities for DSM-related training and employment would exist in northern Manitoba. However, Mr. Dunskey suggested that DSM could create significant employment in comparison to new generation options. He noted that studies of the economic benefits of DSM show that for every million dollars spent on DSM, 15 to 35 person-years of employment were created, which is 2 to 10 times more than for new power plant construction. The high level of job creation associated with DSM was confirmed in a study Mr. Dunskey conducted in four Canadian provinces, and will, he suggests, be further supported by a national DSM study that has yet to be publicly released. Mr. Dunskey stated the DSM employment values for Manitoba will be toward the higher end of the range, based on the study's macroeconomic modelling.¹²¹

¹¹⁷ Exhibit GAC-12, pp. 2-13.

¹¹⁸ Exhibit GAC-12, pp. 2-15, 2-16.

¹¹⁹ Transcript, p. 5183.

¹²⁰ Exhibit MMF-36, p. 6.

¹²¹ Transcript, pp. 8184-8186. Exhibit CAC-62 p.9.

One of the presentations to the Panel provided information on the job creation potential of DSM, indicating that the cost to create a Demand Side Management job could be about \$80,000 per direct/indirect full-time equivalent (FTE) position.¹²² The cost to create a hydropower development job could, in this Presenter's view, be several hundreds of thousands of dollars. He emphasized there were many advantages associated with DSM employment opportunities, such as more permanent jobs, additional transferable skills, and more local employment, as well as a better geographic distribution of jobs, including northern and aboriginal communities.¹²³

5.4.7. Environmental Benefits of DSM

Reducing energy consumption has obvious environment benefits. Manitoba Hydro is projecting greenhouse gas (GHG) emission reductions of 780,000 tonnes as a result of its gas and electric DSM programs over the three-year period, 2014-2017.¹²⁴ Including GHG reductions achieved to date, Manitoba Hydro is forecasting GHG reductions in the order of 4.6 million tonnes by 2028/29.¹²⁵

A long-time advocate of using natural gas as a heating fuel because it frees up electricity for export, GAC emphasized the importance of distinguishing between the GHG impacts of natural gas used for heating and natural gas used to generate electric power. Because of the difference in their efficiencies, (greater than 90% for a gas furnace versus 20-50% for gas turbine or coal power generation), heating with electricity causes significantly more GHGs to be produced by the North American energy system than heating with a high-efficiency gas furnace. GAC argues that converting to electric heat to achieve fossil fuel freedom increases the net environmental impacts associated with the heating choice.¹²⁶

5.4.8. Implementing a Successful DSM Program

An inherent conflict of interest may exist when a utility that derives income from the power it sells also has the responsibility of promoting the use of less electricity through energy efficiency programs. If a utility can make more money from selling electricity than it can if electricity is saved, there can be a disincentive to encouraging customers to reduce their energy consumption. Reduced consumption means less income, unless the energy can be sold on the export market at prices that are higher than domestic electricity rates.

¹²² Transcript, p.7930.

¹²³ Transcript, pp. 7927-7931.

¹²⁴ Exhibit MH-153, p. 5.

¹²⁵ Exhibit MH-180, p. 40.

¹²⁶ GAC-27, p. 32.

Witnesses outlined to the Panel their views on how best to achieve a successful DSM program. Based on their observations and experiences with other jurisdictions in Canada and the United States, they identified the following requirements:¹²⁷

- The creation of DSM targets. Targets are mandated, clear, and measurable. While it is important to have a long-term perspective on desired outcomes, DSM programs need measurable targets to guide program design.
- Aggressive pursuit of DSM targets. The entity charged with delivering DSM programs must be committed to achieving the targets.
- Monitoring and reporting of performance relative to targets. Performance against goals is assessed through independent (third party) audits and evaluations, which is reported publicly.
- An effective body to track performance. Often times this body is the regulator, but it could also be another entity.

In his testimony, Mr. Dunsky explained:

*"I've worked with organizations that have put DSM out there and hope that people will come. And often times they find that they don't, and then declare failure. Those organizations tend not to have the motivation to deliver, to sell. They tend not to have a solid reporting framework, where they have to actually report their results in a specific way. Those organizations that operate under a clear oversight framework with clear reporting requirements, and ideally performance requirements, they deliver and they systematically deliver."*¹²⁸

Manitoba Hydro submitted that such a framework already exists in Manitoba by virtue of *The Energy Savings Act*, which requires Manitoba Hydro to consult with the Province of Manitoba in developing its DSM plans.¹²⁹

In their Closing Submissions, both CAC and MIPUG supported efforts to implement and pursue enhanced DSM programs.¹³⁰

MKO recommended in its closing submission that an entity independent of Manitoba Hydro be established with a mandate to deliver DSM programs in Manitoba.¹³¹ Residential, business, and especially lower income customers often need to be "sold"

¹²⁷ Transcript, pp. 8143-8149; pp. 9420-25.

¹²⁸ Transcript, p. 8147.

¹²⁹ Exhibit MH-204 p. 37.

¹³⁰ Exhibit CAC-91, p. 52; Exhibit MIPUG - 28, p. 61.

¹³¹ Exhibit MKO-11, p. 9.

on DSM. Programs and information need to be provided in a manner that speaks to them directly, and in a clear and convincing manner.

5.5.0 Conclusions of the Panel

In the course of the NFAT Review, the Panel heard much about the importance of DSM. Energy and capacity savings achieved through DSM measures provide a low-cost, reliable, dependable resource that has the added benefit of reducing customer energy bills. Furthermore, DSM measures can provide a hedge for the consumer against increasing energy costs and for the utility against grid parity. In the Panel's view, there are ample reasons for placing DSM measures on an equal footing with supply-side resource options.

Integrated Resource Planning

Integrated resource planning is a regular practice in many jurisdictions. The purpose of an integrated resource plan is to determine analytically what resource is in the best interest of consumers by examining a full spectrum of possible supply-side and demand-side options and measuring them against a collective set of objectives and criteria. This contrasts with traditional methods of utility resource planning, which emphasize supply-side options such as building new generation, transmission, and distribution facilities. Integrated resource planning also tends to be more transparent than traditional resource planning.

The Panel heard evidence that the best practices for integrated resource planning involve placing every conceivable resource option on an equal footing. Manitoba Hydro prepares an annual Power Resource Plan. However, this plan is not tested through an integrated resource planning process.

The Terms of Reference required the Panel to consider "if preferred and alternative resource and conservation evaluations are complete, accurate, thorough, reasonable and sound."

By failing to offer an analysis of conservation measures as a stand-alone energy resource competitive with other generation resources, Manitoba Hydro presented an analysis of conservation measures that was neither complete, accurate, thorough, reasonable, nor sound.

The NFAT Review demonstrated that DSM measures were not equally weighted with other energy options. It was only in the course of the NFAT hearing that it became clear that significantly higher levels of DSM than originally proposed by Manitoba Hydro were

both achievable and economic. The Panel agrees with the Consumers' Association of Canada (Manitoba) that Manitoba Hydro did not treat DSM as a stand-alone resource option competitive with other generation options in its resource planning and analyses.

In its resource planning, Manitoba Hydro added DSM to each alternative plan it examined. By doing this, Manitoba Hydro effectively screened out DSM as an independent resource to be evaluated against other generation resources.

Had Manitoba Hydro undertaken a best-practices integrated resource planning effort, DSM would have been incorporated in the NFAT analysis from the beginning.

Thus, to satisfy anticipated load growth to 2028/29, the Preferred Development Plan delivers 2,025 MW of additional capacity at an estimated cost of \$18.7 billion. Had the Supplemental 2014 Power Smart Plan DSM measures been treated as a stand-alone and equally weighted resource, and added to the capacity from the Keeyask Project, the total capacity addition would be 1,766 MW at a projected cost, including transmission, of \$8.3 billion. This is more than 85% of the net system capacity of the Preferred Development Plan, at a considerably lower cost.

It is clear: DSM must be evaluated as a stand-alone resource in an integrated resource planning process by Manitoba Hydro.

In a time of rapid technological innovation on both the demand and supply side, openness to alternative resources and new technologies will be required. This may involve new methods of saving electricity as well as new methods of generating it, such as wind and solar power. Integrated resource planning provides the analytical framework to evaluate all such energy resource options – hydropower, wind, solar, gas, DSM, or other technologies – on an equal footing. As such, it should be adopted by Manitoba Hydro before any further generating facilities beyond the Keeyask Project are constructed in the future.

DSM Targets

Annual average incremental energy savings in the order of 1.5% (including codes and standards) are achievable and economic. This target contrasts with Manitoba Hydro's 2014-17 Power Smart Plan which forecasts declining future DSM savings. In the Panel's view, it is prudent to assume that DSM savings will continue to be attained and technological advances will present new savings opportunities.

While reliance on on-going incremental DSM savings present a risk that the savings will not be realized, several other North American jurisdictions have successfully achieved

ongoing annual savings at targeted levels. Mitigating this risk, the Panel's recommendation to proceed with a 2019 in-service date for Keeyask will provide sufficient capacity and dependable energy to create a safety margin in case DSM targets cannot be fully achieved in the short term.

While Manitoba Hydro currently consults with the Province of Manitoba as required under *The Energy Savings Act*, there are no clear DSM targets established by the Government. The Panel is of the view that clear, measurable DSM goals and targets are a key component of Manitoba's energy future.

Implementing DSM Programs

There is an inherent conflict of interest when a utility acts as both a seller of electricity and a purveyor of energy efficiency measures. Therefore, the Panel concludes that the planning and provision of DSM services should be divested from Manitoba Hydro.

Jurisdictions such as Vermont that have established independent arm's-length entities to deliver DSM programs have had considerable success in reducing energy consumption and maintaining program performance. The Panel notes that Manitoba Hydro has a long and for the most part successful history with DSM, but in recent years has seen DSM initiatives scaled back and spending reduced. While Manitoba Hydro is to be commended for the new DSM initiatives in its latest Power Smart program, the Panel believes from the evidence before it that the energy savings will not be sustained at levels it considers achievable over the long term. The Panel is also concerned that the utility's renewed focus on DSM may not be continued into the future, in the face of cost constraints and other corporate priorities.

Therefore, in addition to supporting the creation of long-term DSM targets, the Panel also sees great value in establishing an entity independent of Manitoba Hydro to implement DSM programs. The independent arm's-length model has been operating and proven successful in other jurisdictions; the Panel sees no reason why it could not be successfully implemented in Manitoba. The power savings delivered through an independent arm's-length entity would constitute an additional resource available to Manitoba Hydro to meet energy needs.

Monitoring DSM Performance

Monitoring performance against DSM targets was stressed by a number of witnesses as a hallmark of a successful DSM program. The Panel concurs with that view and strongly believes there should be accountability and performance measurement in terms of achieving DSM goals. The Panel also sees the importance of ensuring that performance

evaluation is carried out by someone independent of the DSM provider. For these reasons, DSM savings should be independently audited on an annual basis.

Lower Income and Vulnerable Customers

A significant concern of the Panel is the impact of Manitoba Hydro's projected rate increases over the next 20 years on lower income and vulnerable customers, as discussed in Chapter 9. The Panel notes that DSM measures can help customers mitigate the impact of expected rate increases on their bills. The Panel is of the view that until a new independent arm's-length entity is established to implement DSM programs, Manitoba Hydro should continue to address barriers to lower income customer participation in Power Smart programs. The Panel suggests that a stakeholder consultation process that involves business, residents, and organizations may be able to provide assistance in reaching lower income and vulnerable customers.

Furthermore, the exclusion of customers in arrears from Power Smart programs precludes those that are most in need of these programs from receiving their benefits. Given the projected rate increases that customers will face in the decades ahead, the exclusion of these customers from participating in Power Smart programs needs to be addressed immediately.

The Curtailable Rate Program (CRP)

The Curtailable Rate Program has the potential to result in additional capacity savings. As such, the program merits further review.

Fuel Switching

The Panel supports efforts to reduce the number of customers switching from natural gas to electric heating, and to encourage natural gas use for space and water heating in new construction. Therefore, until a new independent arm's-length entity is established to implement DSM programs, Manitoba Hydro should continue to proceed with its fuel switching and heating fuel choice initiatives to encourage customers to use natural gas for space and water heating. If warranted, fuel switching initiatives should include the provision of a fuel-switching option to biomass in areas where natural gas service is not available.

DSM Employment Potential

Long-term DSM provides enhanced long-term employment, which should be considered an additional socio-economic benefit of DSM programs.

6.0.0 Exports Markets and Contracts

6.1.0 Introduction

Since 1970, Manitoba Hydro has sought out customers and exported its electricity to markets in other Canadian provinces and into the United States. What has been a growing endeavour with increasing revenue is now an essential element of Manitoba Hydro's future plans and strategies.

Manitoba Hydro sees export sales as an opportunity to offset a portion of the costs of its proposed new resource needs, mitigate risks for ratepayers, and meet its commitment to sustain low electricity costs. As Manitoba Hydro has stated in its filing, under the title of Surplus by Design "Exports and transmission access to export markets have been and will continue to be critical for the effective and efficient operation of Manitoba Hydro's system and the development of Manitoba's hydropower resources."¹³²

The Panel's Terms of Reference directed it to consider a number of issues related to exports and Manitoba Hydro's export contracts. In particular, the Panel was asked to examine the reasonableness, thoroughness, and soundness of Manitoba Hydro's export market forecast and its revenue projections.

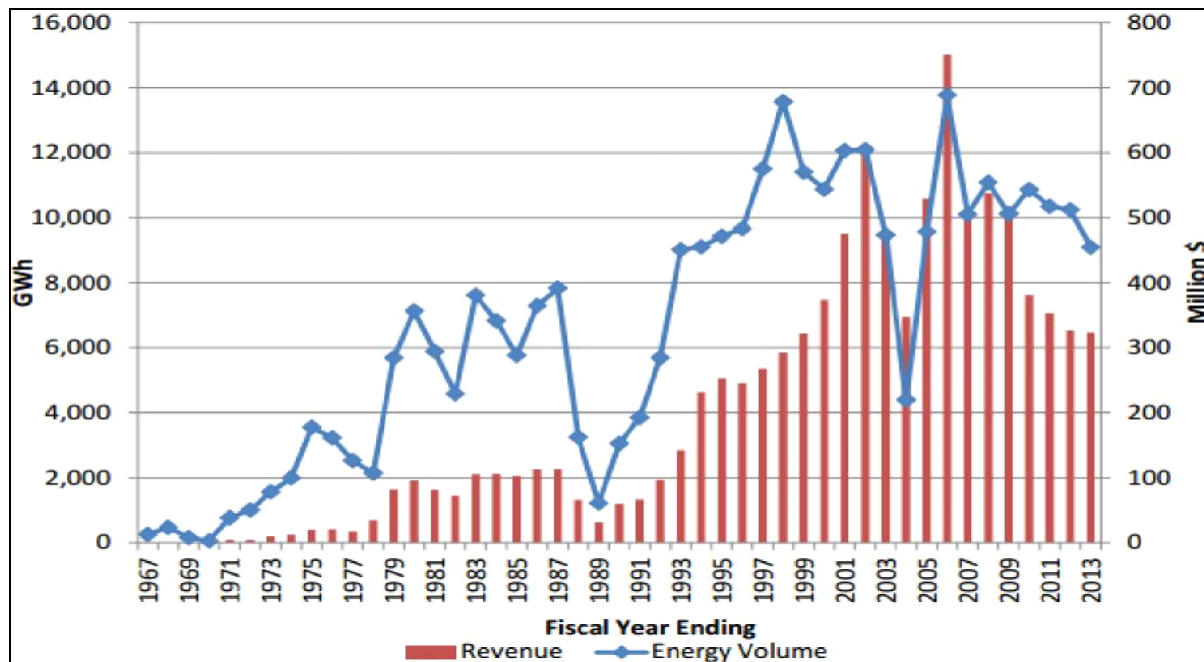
6.2.0 Background and Context

6.2.1. History of Manitoba Hydro's Exports

The annual history of Manitoba Hydro's energy exports (GWh) and gross revenues from those exports are presented in the Figure below:¹³³

¹³² Manitoba Hydro NFAT Submission, Chapter 5, p. 31.

¹³³ Manitoba Hydro NFAT Submission, Chapter 5, Figure 6.3, p. 20.

Figure 6 Manitoba Hydro's Gross Export Revenues and Volumes (1967-2013)

Over the past decade, Manitoba Hydro's exports have generally been between 10,000 and 12,000 GWh/year. Over the period of 2002/03 to 2011/12, about one-third of Manitoba Hydro's total electricity gross revenue has come from exports.¹³⁴

6.2.2. Export Sales, Services and Products

Manitoba Hydro exports four services or commodities: electrical energy generated as measured in GWh, capacity as measured in MW, ancillary services, and environmental attributes. Environmental attributes provide additional value for energy from certain types of generation such as renewable or low-emission generation. These products can be sold in a direct contractual arrangement with another utility. This is often referred to as a bilateral transaction. Alternatively, they can be sold in an organized market where multiple sellers can offer these components to multiple buyers through a competitive market structure.

Manitoba Hydro sells its exports in durations of long-term firm products, medium-term products, and spot-market products. With regard to long-term firm sales, Manitoba Hydro determines its dependable surplus power availability and then seeks to make surplus firm energy available for sale under agreements with terms greater than one year. These sales are done on a bilateral basis directly with counterparties. These long-term sales include both system participation power sales and diversity exchange sales,

¹³⁴ Exhibit LCA-9, p. 6-4.

and are usually of 10- to 15-year durations with utility companies in the U.S. Medium-term arrangements are sales with terms longer than one day but less than one year. Spot market sales are defined as sales with timeframes of one day or less. They are done on a bilateral basis or through structured markets, and administered by regional transmission organizations, such as the Midcontinent Independent System Operator, Inc. (MISO).¹³⁵

6.2.3. Surplus By Design

Manitoba Hydro's focus on exports and transmission access to export markets is a continuation of past practices. In its Preferred Development Plan and in many of the alternatives, exporting energy is an underpinning strategy and goal of Manitoba Hydro. Continued and increased exports are seen as the means to contribute to the financing of its new generation needs. By design, in all flow conditions other than the lowest flow period of the past 99 years, there will be hydro-generation capacity surplus to domestic load and committed firm export requirements. Furthermore, hydro developments result in large additions of capacity that produce surpluses of energy compared to what is needed for domestic load, especially in the early years of a new hydro development.¹³⁶

During the hearings, this strategy was presented as the "opportunity" side of the ledger, or the "opportunity pathway." As Manitoba Hydro CEO Scott Thomson indicated on the first day of the hearings:

"... Our statutory mandate contemplates exports on appropriate terms. As I'll discuss later, exports have been a major reason why Manitoba Hydro's rates remain so low relative to many other jurisdictions. Revenues from exports help to offset costs for domestic customers."¹³⁷

Others had differing views as to this approach and its implications. In its closing submission, the Consumers' Association of Canada (Manitoba) Inc. (CAC) made note of the "merchant plant" concept (that is, building a generating station for the export market) underlying Manitoba Hydro's export plans and pathways. In CAC's view, this approach exposes ratepayers to substantial risks.¹³⁸

This notion of the "merchant plant" and its implications was best articulated in the report and testimony of Morrison Park:

¹³⁵ Exhibit LCA-9, p. 5-8.

¹³⁶ Manitoba Hydro NFAT Submission, Chapter 5, pp. 31-32.

¹³⁷ Transcript, p. 79.

¹³⁸ Exhibit CAC-91, pp. 8-9.

“Considered more broadly, Manitoba is simply a price taker in the MISO market, whether it is taking prices in short-term markets, or in a longer-term market for bilateral arrangements with specific counterparties.... As a result, the longer-term firm contracts are not mitigating market risk or exposure for Manitoba Hydro, but merely apportioning the market risk accepted in pursuing the Preferred Development Plan.

In this respect, Manitoba Hydro is acting as a “merchant” investor, taking substantial market risk based on expectations, or bets, about the future. While “probabilities” have been placed on different potential futures through the scenario modeling process, fundamental market risks are necessarily imbedded in some Resource Plans to a far greater extent than in others.

Prices will either turn out to be high, and ratepayers will benefit, or they will turn out to be low, and ratepayers will have to shoulder more of the burden of Manitoba Hydro's costs. Either way, ratepayers can have no certainty in advance, and no choice in the matter.”¹³⁹

6.3.0 Export Markets

6.3.1. Canadian Export Markets

In its planning, Manitoba Hydro examined the long-term potential and value of both its current markets and potential markets in Ontario and Saskatchewan. Manitoba Hydro currently has a relatively small, 200 MW, export capability into Northwestern Ontario. There is already ample generation and a relatively small load within Northwestern Ontario. The Ontario interconnection through east-west transmission lines is insufficient for a major new sale into southern Ontario. In the view of Manitoba Hydro, this makes the likelihood of increased future power sales to Ontario unrealistic.¹⁴⁰

Manitoba and Saskatchewan have had ongoing discussions about future power sales. Over the last decade, SaskPower appears to have focused on natural gas-fired generation of electricity, with Saskatchewan being Canada's third-largest producer of natural gas. Recently Manitoba Hydro and SaskPower entered into a Memorandum of Understanding (MOU) dated October 7, 2011 regarding SaskPower's potential

¹³⁹ Exhibit MPA-3, pp. 68-69.

¹⁴⁰ Manitoba Hydro NFAT Submission, Chapter 5, pp. 49-51.

purchase of 25 MW from Manitoba Hydro, commencing in approximately 2015. That MOU was converted to a non-binding Term Sheet, dated September 13, 2013.¹⁴¹

6.3.2. United States/MISO

Manitoba Hydro has long sold power to public utilities in the MISO territory comprising 15 of the United States. Manitoba Hydro pursues U.S. exports through bilateral contract negotiations with MISO members, especially utilities in Minnesota. The primary reason for Manitoba Hydro's focus on U.S. exports and interconnections with the MISO market is the Minneapolis–Saint Paul metropolitan area of Minnesota, which represents the closest and largest population centre and electricity market to southern Manitoba. Minnesota is a significant net importer of electricity, providing a market for Manitoba Hydro's surplus power.¹⁴² Given the existing U.S. interconnections and size of the Midwestern U.S. market, over 85% of Manitoba Hydro's exports have been sold into the MISO market in recent years. Manitoba Hydro continues to rely on the MISO energy market for the majority of its exports.

6.4.0 Export Market Forecast

6.4.1. Introduction

During the course of the NFAT Review, the Panel heard testimony about the transformation of the electricity marketplace. As a result of innovation, technology advances, concerns about climate change and impending regulations, power utilities are facing an uncertain world which makes planning and forecasting challenging. These factors include:

- The flattening of load growth throughout the U.S.;
- The cost of fuels, especially natural gas;
- The impact and timing of climate policies and regulations, especially as they pertain to carbon pricing;
- The retirement and other restrictions on power sources, such as coal-fired and nuclear generation;
- Public acceptance of new power options, especially shale gas hydraulic fracturing;

¹⁴¹ Manitoba Hydro NFAT Submission, Related Documents, Export Contracts, Saskatchewan Power Corporation and Manitoba Hydro Term Sheet, September, 13, 2013.

¹⁴² Manitoba Hydro NFAT Submission, Chapter 5, p. 38.

- The rate and adoption of new energy technologies, such as wind, solar photovoltaic, and ground source heating; and
- Changes in the generation sources that might come with grid parity (that is, distributed generating resources that achieve cost parity with grid supplied power).

The potential impacts of distributed generation achieving grid parity are discussed in Chapter 4. Proliferation of grid parity technologies in Manitoba Hydro's export markets could dramatically limit load growth in those markets and compete on price with grid power, effectively capping export prices.

6.4.2. The Nature of the MISO Market: Influences and Determinants

Overview of the Market Drivers

Electricity demand in both Canada and the U.S. is assumed by Manitoba Hydro to continue to increase over its 35-year planning horizon. The Energy Information Administration's (EIA) Annual Energy Outlook 2013 reference case projects overall U.S. load growth of 28% between 2011 and 2040 (0.9% per year).¹⁴³

The electricity market is driven not just by the cost of generation but by environmental considerations and policies. For the foreseeable future, environmental considerations, including the anticipated effects of electric industry regulations on greenhouse gas emissions, will continue to influence the generation choices of utilities in MISO and the U.S. as a whole. Many market participants and observers, including Manitoba Hydro, anticipate legislation or regulation that will put a price on electricity generated with carbon-emitting resources such as coal and natural gas. Such policies, often referred to as "carbon taxes", ultimately favour non-greenhouse gas (GHG) emitting generation sources such as hydroelectricity generated by Manitoba Hydro.

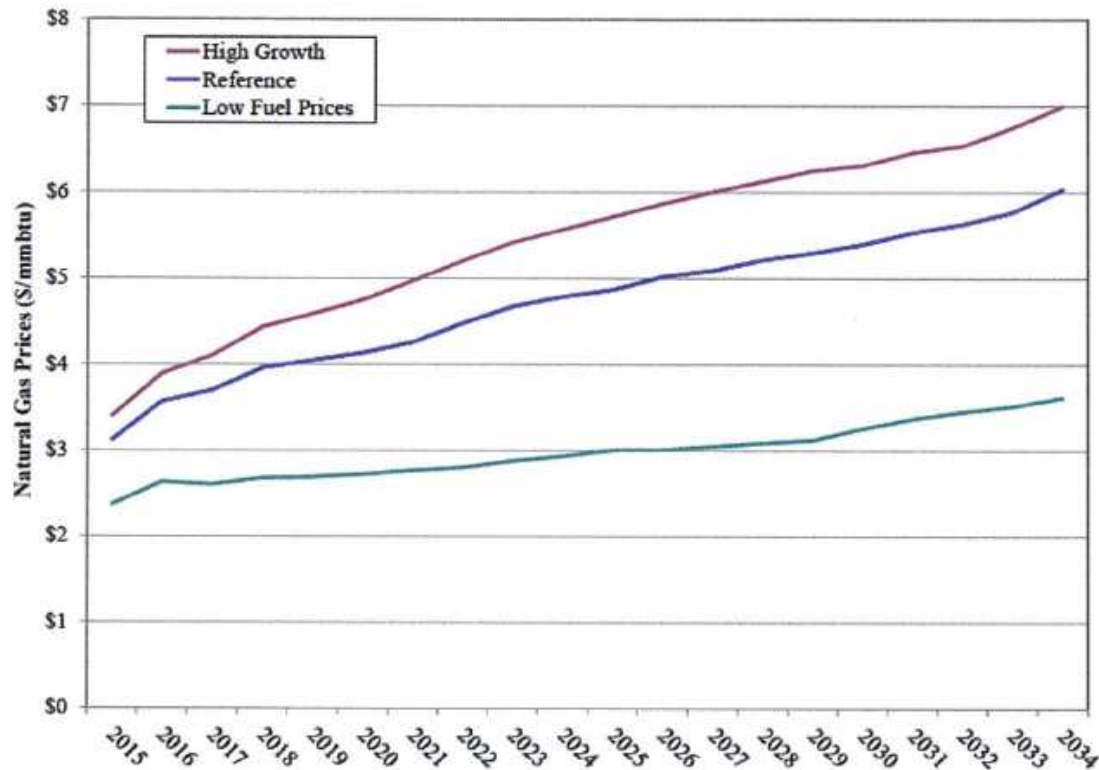
Countering the purely environmental considerations of electricity generation are the recent developments in natural gas extraction that have increased natural gas supplies and reduced the cost of production. The combination of horizontal directional drilling and hydraulic fracturing of shale rock has resulted in abundant new supplies of natural gas. Since the highs of 2008, natural gas prices have declined. While future prices are, as always, the subject of prognostication and speculation, the expectation from industry analysts is that natural gas prices will moderately increase over the next decade.¹⁴⁴

¹⁴³ Manitoba Hydro NFAT Submission, Chapter 3, p.1. See also, Manitoba Hydro NFAT Submission, Appendix 6.3.

¹⁴⁴ Manitoba Hydro NFAT Submission, Chapter 3, p.31.

While the Independent Expert Consultant, Potomac Economics, did not produce their own natural gas price forecast, they did provide the EIA's forecast, depicted in the following Figure:¹⁴⁵

Figure 7 Energy Information Agency Natural Gas Price Forecasts (2013 Energy Outlook, real US\$/mmBtu at Henry Hub)



Future MISO Generation Mix

Several factors are driving expected change in the electricity generation mix in MISO. Environmental policies are growing in importance for electricity generators and will increase the cost of refurbishing coal plants and accelerate the pace of coal plant retirements.

Investment decisions in new generation for MISO market participants will be driven by capital costs, fuel costs, financing costs, and regulatory considerations. Manitoba Hydro expects that constraints on new coal generation in the U.S. along with continued low natural gas prices will drive the choice toward new natural gas generation.¹⁴⁶ At the

¹⁴⁵ Exhibit POT-2-1, Appendix A-1 p.47.

¹⁴⁶ Manitoba Hydro NFAT Submission, Chapter 3, pp. 1-3.

same time, new renewable portfolio standards and lower capital costs could move investment towards wind and solar power.

As a part of the NFAT Review, the Independent Expert Consultant MNP reviewed the MISO generation mix. MNP concluded that by 2020 a number of factors will converge: coal plants grappling with compliance with carbon policy; new mercury policy; new water use regulations; and more stringent air pollutant regulations. These will all have the effect of retiring coal power plants. Although the rate at which it will occur is open to debate, MNP expects between 10 and 20 GW of coal generation to retire by 2025, representing a possible reduction in coal generation of at least 17%. Potomac Economics, on the other hand, expects only 6 GW of coal plant retirements in the MISO market based on the EIA's view of the expected retirements.¹⁴⁷

MNP believes that new energy requirements will be met with a combination of natural gas combined cycle generators and wind investments over the period of 2015 to 2037. This may dampen the amount of coal that currently sets marginal prices in the MISO market, and move more gas to the marginal fuel.¹⁴⁸ MNP suggested the forecast changes might have the effect of supporting hydroelectricity development.¹⁴⁹

Potomac Economics' view of the future MISO generation mix likewise foresees new combined cycle gas turbines and wind generation. Potomac agrees with the EIA's forecast of 6 GW of coal plant retirements which differs from the MISO Transmission Expansion Planning forecast of 12 GW of retirements.¹⁵⁰

Impact of U.S. Renewable Portfolio Standards

A Renewable Portfolio Standard (RPS) is a U.S. regulation that requires the increased production of energy from renewable energy sources, such as wind, solar, biomass, and geothermal. Hydro power is not always included in a particular state's RPS; hydro generating plants with a capacity less than 100 MW may be included in Minnesota's RPS, while any new hydro plant built after 2010 is eligible for Wisconsin's RPS.¹⁵¹ The RPS mechanism generally places an obligation on load serving utilities to procure a specified fraction of their electricity from renewable energy sources.

¹⁴⁷ Exhibit POT-1, MH/POT-022a.

¹⁴⁸ Exhibit MNP-5, p.30.

¹⁴⁹ Exhibit MNP-5, p. 30.

¹⁵⁰ Exhibit POT-1, MH/POT-022a.

¹⁵¹ Manitoba Hydro NFAT Submission, Chapter 5, p.54.

Independent Expert Consultant La Capra Associates concluded that neither Minnesota nor Wisconsin would be short of renewable supply under current policies.¹⁵² This could reduce Manitoba Hydro's prospects for future 'clean' hydro electricity sales.

Impact of Carbon Pricing

Carbon pricing has the potential to greatly influence the market price for electricity. As a carbon price is implemented, the cost of fossil fuel-fired generation goes up in proportion to the level of carbon emissions associated with each individual resource. For example, the carbon price component for electricity generated from coal is approximately two times the carbon price component of electricity generated from a combined cycle gas turbine plant. Given that the MISO market is heavily coal-dominant and despite anticipated coal plant retirements, Manitoba Hydro's primary market will be highly susceptible to the presence or absence of carbon pricing. Manitoba Hydro noted that carbon pricing will be a major driver of future power prices.

The Panel also heard from a number of expert witnesses on this matter. MNP prepared a low, reference (or base), and high carbon price forecast. The low case assumed no cap-and-trade legislation until 2030 and a \$10/tonne floor price. MNP's reference or base case assumed legislation in 2021 and a \$13.14/tonne of carbon floor price. MNP's high case foresaw cap-and-trade legislation in effect in 2020 and a floor price of \$15.80/tonne of carbon.¹⁵³

In his review of the carbon costs, Dr. Gotham indicated that there was considerable uncertainty with the use of carbon costs in the export price forecasts. He also concluded that the imposition of carbon restrictions could have a significant impact on projected export revenues. Referencing the public forecasts of the Brattle Group, moderate carbon costs could result in an increase of \$13-14/MWh in the market price, while the absence of carbon costs could see Manitoba Hydro's export prices and revenues 20-25% lower, or a shortfall of \$1.8 to \$2.3 billion based on the expected present value of Manitoba Hydro's export revenues.¹⁵⁴

Potomac viewed an equal probability of there being, or not being, a future carbon price. Potomac prepared price forecasts reflecting both scenarios, as shown in the graph below. The Reference and High Growth scenarios both anticipate a carbon price beginning at \$13.14/tonne in 2021 as suggested by MNP, while the Reference No Carbon and High Resource cases assume no carbon price.¹⁵⁵ According to Potomac's

¹⁵² Exhibit LCA 7-1, p. 4-18.

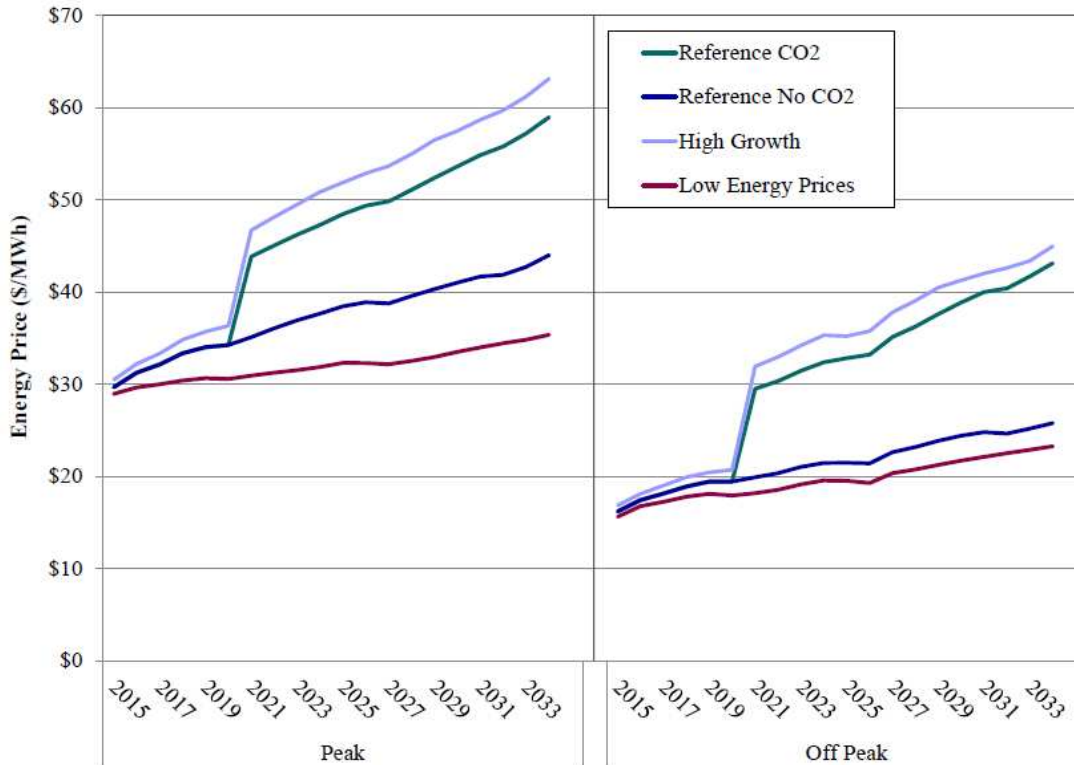
¹⁵³ Exhibit MNP-5, p. 31.

¹⁵⁴ Exhibit CAC 26-1, p. 7.

¹⁵⁵ Exhibit POT-4 p.27 and Exhibit POT-3 pp. 25-28.

graph, on-peak electricity export prices are increased by 25-30% by carbon pricing; off-peak export prices are increased by 50-65%.

Figure 8 Potomac Economics Export Price Forecasts



Transmission Congestion

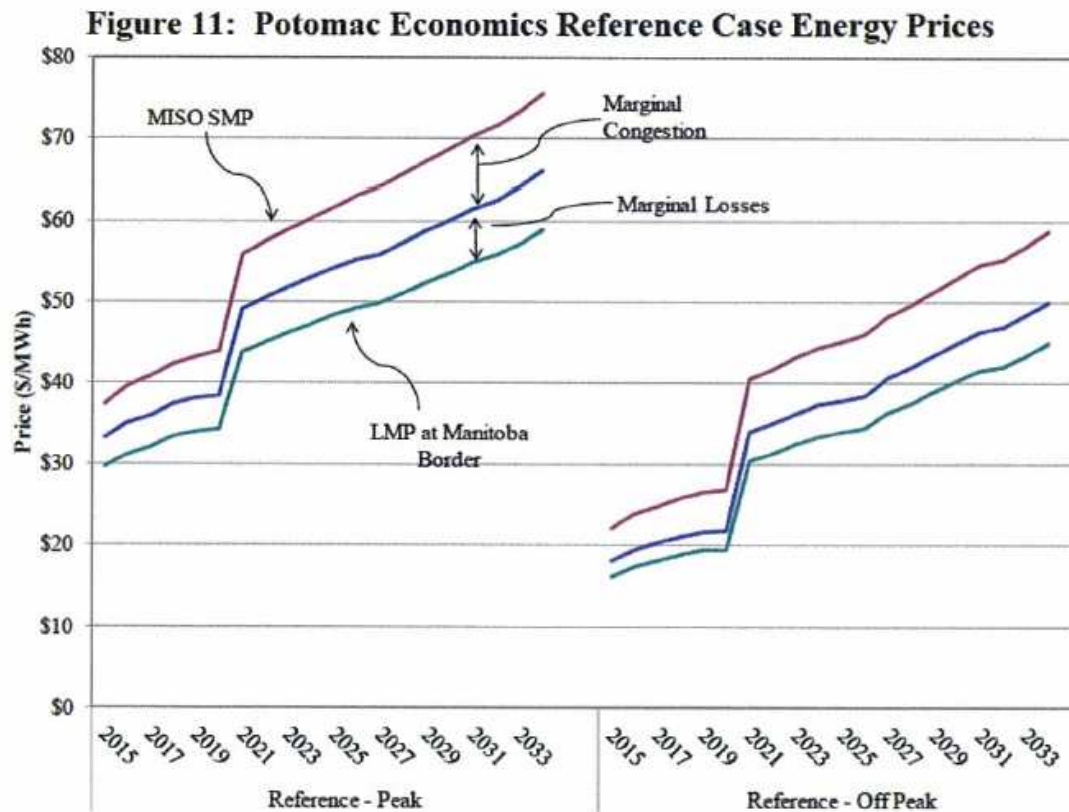
Transmission congestion occurs on electric transmission grids when actual or scheduled flows of electricity over a line or piece of equipment are constrained below desired levels. Transmission congestion shrinks the size of the export market since it excludes participants from outside the congested area. In his analysis, Dr. Gotham concludes that transmission congestion will have an impact on export prices, and could reduce annual average prices by 3-12% at the Minnesota Hub, which is one of several price clearing locations within MISO.¹⁵⁶ In Dr. Gotham's view, there is substantial congestion between Minnesota and Wisconsin and the rest of the MISO market which serves to reduce the market prices in these locations, which in turn, will reduce Manitoba Hydro's export revenues.¹⁵⁷

¹⁵⁶ Exhibit CAC 26-1, pp. 4-6.

¹⁵⁷ Exhibit CAC 26-1, p.9.

Potomac Economics also examined transmission congestion. They developed an econometric model to estimate how key factors that contribute to congestion, such as system marginal prices, market generation, ramp requirements and wind share of generation, affect market prices. Potomac Economics incorporated these congestion effects into its forecast of market prices. The graph below shows how congestion depresses the System Marginal Price, which in conjunction with transmission losses, results in a lower Locational Marginal Price at the Manitoba-Minnesota border where the prices for Manitoba Hydro's exports are settled.¹⁵⁸

Figure 9 Potomac Economics Reference Case Energy Prices



6.4.3. Energy Price Forecasts

MISO market electricity prices consist of the market price for energy, which includes the variable cost of generation including fuel, and the price of capacity, which reflects the capital, financing, and fixed costs of investing in new generation. Energy and capacity prices incorporate the effects of supply and demand, economic conditions, commodity prices, and the impact of existing or potential energy and environmental policy. Based

¹⁵⁸ Exhibit POT 2-1, pp. 29-34.

on these factors, electricity prices are expected to increase in real terms. For purposes of its planning and the development of its alternatives, Manitoba Hydro used an export price forecast that is an average of six forecasts provided by independent consultants. With one exception (the Brattle Group), these forecasts were not available on the public record due to their proprietary and commercially sensitive nature. These forecasts were available to the Panel *in-camera*.

Potomac Economics is the Independent Market Monitor of MISO, a role that requires Potomac to closely monitor prices, investments, market structure, and market outcomes. Potomac formulated and developed their own MISO market price forecasts using publicly available information, which they compared to Manitoba Hydro's independent consultants' forecasts. Potomac created a forecast based on MISO supply and demand characteristics and recent market outcomes, along with input assumptions from the EIA. Potomac's models relied on lower natural gas price forecasts, lower rates of demand growth, and lower quantities of coal plant retirements than most of the six consultants.¹⁵⁹

Each of Manitoba Hydro's consultants' forecasts was evaluated by Potomac, although Potomac was not provided access to the underlying assumptions behind the consultants' forecasts. Potomac forecasts lower prices than the Brattle Group, and generally lower prices than the other consultants. Potomac noted that the Brattle Group assumes carbon pricing beginning in 2020 at \$15/tonne and increasing to \$24/tonne by 2034. Potomac believes Brattle overstates the emissions and fuel costs of gas-fired and coal-fired generators and thus overstates forecast energy prices, while at the same time understating capacity prices. Potomac was not able to disentangle these conflicting effects and thus does not recommend the NFAT Panel use Brattle's forecast. For various reasons, contained in commercially sensitive information reviewed *in-camera*, Potomac was not able to recommend the use of any of the other Manitoba Hydro consultants' forecasts. Potomac recommended their own forecast be used by the NFAT Panel to evaluate Manitoba Hydro's Preferred Development Plan business case because Potomac does not find the Manitoba Hydro consultants' forecasts to be credible.¹⁶⁰

Dr. Gotham commented that if carbon prices do not materialize, MISO market prices will be lower by 20-25%. Dr. Gotham quoted La Capra's finding that the impact of carbon prices on the Preferred Development Plan are significant, as the absence of a carbon

¹⁵⁹ Exhibit POT-2 p.5.

¹⁶⁰ Exhibit POT-2 p.41.

price lowers the NPV advantage of the Preferred Development Plan over the All Gas Plan by approximately \$340 million.¹⁶¹

Dr. Gotham prepared and presented a review of export price forecasts using MISO's Transmission Expansion Plan, Brattle Group and Potomac Economics cases with the lowest carbon price assumptions.¹⁶²

Table 5 Export Price Forecast Comparison: No Carbon/Low Carbon (US\$/MWh)

	MTEP	Brattle	Potomac
2017	29.65	30.00	26.00
2022	32.54	33.00	29.00
2027	37.78	37.00	31.00

In Dr. Gotham's view: *"If the electricity price projections from The Brattle Group are indicative of Manitoba Hydro's forecast from the average of the vendor forecasts, it is reasonable. If the Manitoba Hydro forecast is higher than the Brattle forecast, there is cause for concern."*¹⁶³

6.4.4. "Window of Opportunity"

In support of its Preferred Development Plan, Manitoba Hydro argues that there is a window of opportunity to develop new hydroelectric generating resources. According to Manitoba Hydro, along with new transmission interconnections, new hydroelectric generating stations can take advantage of marketplace opportunities, if decisions are made now and proposed construction begins as planned. Manitoba Hydro identified the following factors as favoring new hydro development: expectations of MISO load growth; retirements of older, smaller coal plants in MISO; and additional carbon related costs and environmental restrictions for fossil-fired generation. Furthermore, Manitoba Hydro has negotiated transmission project agreements and Minnesota Power has undertaken to champion them to the U.S. regulatory authorities. Manitoba Hydro is concerned that it might miss out on improved transmission opportunities if it does not proceed with the U.S. interconnection.¹⁶⁴ Manitoba Hydro indicated that a number of the already negotiated, but conditional export contracts are linked to the power generated by Keeyask and/or Conawapa.¹⁶⁵

¹⁶¹ Transcript, p.8438.

¹⁶² Exhibit CAC-26-1, pp. 7-9.

¹⁶³ Exhibit CAC-26, p. 9.

¹⁶⁴ Manitoba Hydro NFAT Submission, Chapter 6, p. 6.

¹⁶⁵ Manitoba Hydro NFAT Submission, Chapter 6, p. 28. Exhibit MH-99, See also Appendix 6.1.

As part of its analysis, La Capra examined Manitoba Hydro's reasoning for a "window of opportunity." La Capra noted that one of Manitoba Hydro's rationales for this window was the ability to respond to Renewable Portfolio Standards requirements. However, current U.S. RPS requirements are primarily focused on increasing U.S. wind generation capacity, not Canadian hydro capacity.¹⁶⁶

When Manitoba Hydro agreed to a Term Sheet with WPS in 2008, Manitoba Hydro also placed firm transmission reservations in order to have the transmission capacity to export power from Minnesota to Wisconsin. These reservations placed Manitoba Hydro at the front of the queue for access to new transmission facilities from Minnesota to Wisconsin. When available, this transmission access opens up new markets for Manitoba Hydro's exports, in essence doubling its market size by being able to export beyond Minnesota into Wisconsin. In Manitoba Hydro's view, failure to take advantage of the window of opportunity by building the 750 MW interconnection and completing the WPS sale would result in the firm transmission reservations being lost. According to Manitoba Hydro, the 750 MW Great Northern Transmission Line is a once in a lifetime opportunity.¹⁶⁷

6.4.5. Export Volume Assumptions

Manitoba Hydro assumes that all surplus electricity can be sold either as long-term firm energy or as on-peak and off-peak opportunity sales. Potomac Economics concludes that because Manitoba Hydro's exports are a small percentage (less than 2%) of the total MISO market volumes, Manitoba Hydro will be able to sell all of its surplus power into MISO, and Potomac's price forecasts account for these additional volumes.

Potomac disagreed with Manitoba Hydro's assumption that it can sell 100% of its dependable energy under long-term firm contracts at the premium prices that Manitoba Hydro assumes for those long-term firm contracts. Potomac Economics reviewed this assumption and suggested that Manitoba Hydro could export 91% of its surplus dependable energy under long-term firm contracts.¹⁶⁸ However, it has not been conclusively demonstrated that all of this surplus dependable energy will achieve capacity revenues in addition to energy revenues.

¹⁶⁶ Exhibit LCA-11, pp. 8-24.

¹⁶⁷ Exhibit MH-204 p.99.

¹⁶⁸ Exhibit POT-2-2, pp. 43-44; Transcript, p. 4686, Potomac Undertaking 86, Transcript, p. 4687.

6.5.0 Export Prices, Revenues Forecast and Contracts

6.5.1. Existing and Future Export Contracts

The following is a listing of the current and future signed export contracts:¹⁶⁹

Table 6 List of Current and Future Manitoba Hydro Export Contracts

Customer	Contract Type	Term
Northern States Power	150 MW Seasonal Diversity (Summer)	May 1991 to April 2015
Northern States Power	200 MW Seasonal Diversity (Summer)	November 1996 to April 2015
Northern States Power	500 MW System Participation	May 2005 to April 2015
Minnesota Power	50 MW System Participation	May 2009 to April 2015
Minnesota Power	50 MW System Participation	May 2015 to May 2020
Minnesota Power	250 MW System Participation	June 2020 to May 2035
Minnesota Power	Energy Exchange	June 2020 to May 2035
Great River Energy	150 MW Seasonal Diversity	May 1995 to October 2014
Great River Energy	200 MW Seasonal Diversity	November 2014 to April 2030
Northern States Power	125 MW System Participation	May 2021 to April 2025
Northern States Power	375/325 MW System Participation	May 2015 to April 2025
Northern States Power	350 MW Seasonal Diversity	May 2015 to April 2025
Wisconsin Public Service (100 Product A)	100 MW System Participation	June 2021 to May 2025
Wisconsin Public Service (100 Product B)	Surplus Energy	June 2025 to May 2029
Wisconsin Public Service	308 MW System Participation	January 2027 to May 2036
Wisconsin Public Service	108 MW System Participation*	June 2016 to May 2021
Note: The Wisconsin Public Service contracts (Product A and B) will terminate if the 308-system power sale begins before May 31, 2029.		

¹⁶⁹ Exhibit PUB/MH 1-280R and Exhibit MH-99.

6.5.2. Impact of Exports on Selected Plans

Morrison Park examined the relationship of energy prices with ratepayer impacts. Their conclusion was that high energy prices would lead to lower Manitoba ratepayer costs in the Plans based on the Keeyask and Conawapa projects. In their recent work, Morrison Park compared the role of exports in the 2013 versions of the Plans with the role of exports in the 2014 updated versions (calculated from the 6% NPV figures):¹⁷⁰

Table 7 Exports as % of Total Revenues : 2013 vs. Updated Plans

	Plan 1: All Gas	Plan 2: K22/Gas	Plan 4: K19/Gas 24/250	Plan 5: K19/Gas 25/750	Plan 6: K19/Gas 31/750	Plan 14 (PDP)
2013 Version	8.6%		14.2%		13.8%	17.3%
2014 Version	13.9%	16.1%	20.2%	21.4%	21.1%	27.5%
Change	+5.3%		+6.0%		+7.3%	+10.2%

The significant increases in revenues, from exports, for Manitoba Hydro across all of the updated Plans result from the much lower domestic demand in Manitoba due to increased DSM programs. The percentage of revenues from exports for the updated 2014 All Gas Plan 1 is similar to the percentage of revenues from exports for the 2013 versions of Plans 4 and 6. The updated versions of Plans 4 and 6 are now almost 50% more export oriented, and in fact are projected to generate a greater percentage of revenue from exports than the 2013 version of the Preferred Development Plan.

6.5.3. Assessing the Contract Terms and Conditions**Minnesota Power Contracts**

In its NFAT Submission and during the hearings, Manitoba Hydro indicated that several of its signed export contracts were contingent on the construction of Keeyask and/or Conawapa. For the Minnesota Power 250 MW sale, it was noted that a condition precedent (in favour of Manitoba Hydro and which Manitoba Hydro could waive) existed related to Keeyask construction commencing by June 2016. A two-year delay for regulatory purposes is permitted. While the construction of Keeyask is a condition precedent, which Manitoba Hydro could choose to waive, Manitoba Hydro stated that it had always represented to Minnesota Power that Keeyask would be built to serve the MP 250 MW contract. In Manitoba Hydro's view, the Minnesota Power sale is uncertain without the start of Keeyask construction by June 2016.

¹⁷⁰ Exhibit MPA 3-1, pp. 22-23.

Manitoba Hydro expressed further concern that Minnesota Power may back away from its application to build the 750 MW Great Northern Transmission Line if Keeyask was not also built. Manitoba Hydro stated that Minnesota Power was counting on the wind storage benefits from new hydraulic generation, implying that Minnesota Power was counting on Keeyask. Manitoba Hydro had previously stated that Keeyask does not provide wind storage benefits because of the relatively small size of its forebay. However, significant wind storage exists in Manitoba Hydro's overall system.

Manitoba Hydro can control the level of Stephens Lake to increase or decrease flow through Kettle, Long Spruce, Limestone, and Conawapa, which makes the lake act as a storage battery for wind energy. Conawapa enhances the effective energy storage capacity of Stephens Lake by approximately 25%.¹⁷¹

Manitoba Hydro and Minnesota Power also have an agreement to exchange wind energy. Minnesota Power has the option of storing 250 GWh, or up to 383 GWh, of wind energy in Manitoba Hydro's water reservoirs. If Manitoba Hydro accepts the wind energy, it then has the obligation to return energy when requested by Minnesota Power.¹⁷²

Wisconsin Public Service Contracts

According to Manitoba Hydro, the WPS 100 MW sale is contingent on Keeyask being in service.¹⁷³ However, construction and commissioning of Keeyask are not conditions precedent in favour of WPS in this contract. Manitoba Hydro's conditions precedent for this contract are considered trade secrets and thus commercially sensitive.¹⁷⁴ However even if construction or commissioning of Keeyask was a condition precedent in favour of Manitoba Hydro, Manitoba Hydro could waive the condition and serve the WPS 100 MW contract from its existing resources.

The WPS 308 MW contract has conditions precedent in favour of Manitoba Hydro that allow the contract to be canceled if either Keeyask or Conawapa do not enter service. WPS has no condition precedent requiring Keeyask and Conawapa to be built, however there is a termination clause that allows WPS to cancel the contract if the 4th unit of Conawapa does not enter service by June 2031. There was no evidence provided in the hearing that WPS would exercise this termination clause if Conawapa was not built.¹⁷⁵

¹⁷¹ Transcript, pp.1671-1672, 1683-1684.

¹⁷² 250 MW Energy Exchange Agreement - MHEB and MP, May 19, 2011.

¹⁷³ Exhibit MH-99.

¹⁷⁴ Exhibit MH-31-3, p. 73.

¹⁷⁵ 308 MW System Power Agreement between MHEB and WPS, February 26, 2014. p. 114 to 120, 123

In their testimony, Morrison Park made mention of this situation, when contracts and commercial agreements must be terminated by one party. In Morrison Park's view, commercial transactions are ended all the time; there are consequences in terms of financial losses as well as lost reputation and commercial trust. These are difficult to measure, but are nevertheless real.¹⁷⁶

6.5.4. Export Revenue Forecasts

Manitoba Hydro's Export Contract Revenues

Manitoba Hydro began the hearings by indicating that export sales revenues would be a significant aspect of their Preferred Development Plan. While initially, Manitoba Hydro estimated export revenues from firm contracts at \$9 billion, this amount was subsequently revised to \$6.9 billion.¹⁷⁷

Table 8 Manitoba Hydro's Gross Export Revenues

Gross Export Revenues and Sales 2015-2037	\$ Billions
Dependable Capacity and Energy¹⁷⁸	5.88
Contracted Surplus Energy¹⁷⁹	1.05
Total Contracted Sales (sub-total)	6.93
Opportunity Sales (non-contracted peak and off-peak)	10.08
Total Gross Extra-Provincial Revenues¹⁸⁰	17.01

In addition to the contracted energy and capacity, Manitoba Hydro also forecasts that between 2015 and 2037, it will sell an additional \$3.416 billion worth of 'Non-Contracted Surplus Energy Sales', which amounts are included in the Opportunity Sales in the above Table. Manitoba Hydro seeks to achieve firm (long term and short term) bilateral sales to its existing counterparties, for its presently 'non-contracted surplus'. Any of this surplus that is not contracted would then be sold as opportunity sales into the MISO market.

Based on La Capra's review of Manitoba Hydro's bilateral firm contracts, the Panel accepts the quantification of Manitoba Hydro's contracted dependable capacity and energy revenues as well as the contracted surplus energy revenues. However, the

¹⁷⁶ Transcript, p.7264.

¹⁷⁷ Transcript, pp. 97 and 140; Exhibit MH-100.

¹⁷⁸ Exhibit MH-100.

¹⁷⁹ Exhibit MH-100.

¹⁸⁰ Exhibit MH-104-12-7.

Panel notes that diversity revenues are not guaranteed revenues as the counterparty has no obligation to purchase any diversity energy.

Diversity Exchange Agreements¹⁸¹ augment Manitoba Hydro's winter capacity by 350 MW with Northern States Power, and by an additional 200 MW with Great River Energy. In summer, Manitoba Hydro is obligated to dedicate 550 MW of capacity to Northern States Power and Great River Energy for all hours of the summer months. While there is no obligation for Northern States Power or Great River Energy to buy any energy from the dedicated capacity, Manitoba Hydro is prohibited from selling the dedicated capacity during the summer months under long-term or short-term contracts.¹⁸² Furthermore, although diversity exchanges are served from Manitoba Hydro's dependable resources, the energy prices are transacted at market prices, not fixed contract prices.

Relationship of Export Contract Revenues to In-Service Costs

From an accounting and rate setting perspective, when a generating station or transmission line comes into service, Manitoba Hydro no longer capitalizes the related costs. Rather the accumulated costs, including the financing charges, depreciation expense and operating and maintenance expenses are charged through to domestic ratepayers by way of Manitoba Hydro's Operating Statement. Manitoba Hydro then proposes rates, at regular General Rate Applications before the Public Utilities Board, to recover the costs included in the Operating Statement. Manitoba Hydro contends that while some of the in-service costs of new capital assets are directly attributable to a particular asset, the benefits are not.¹⁸³ Manitoba Hydro submits that the appropriate approach to the evaluation of capital assets such as Keeyask and new transmission lines is through development plan comparisons.

In addition to development plan comparisons, the NFAT Terms of Reference direct the Panel to examine "[T]he impact on domestic electricity rates over time with and without the Plan and with alternatives."¹⁸⁴

Manitoba Hydro provided an indication of the in-service costs for various capital projects that are included and/or required in its Preferred Development Plan. Bipole III will enhance reliability for domestic customers and will be used for transmission of Keeyask energy. In 2025, the annual in-service costs for Keeyask are \$486 million; the costs for

¹⁸¹ Exhibits MH-99, pp. 2-3 and MH-100, pp. 1-5.

¹⁸² 350 MW Diversity Sale Agreement with NSP dated May 27, 2010 and 200 MW Diversity Exchange Agreement with GRE dated July 26, 2013.

¹⁸³ Exhibit MH-210 and MH-211.

¹⁸⁴ NFAT Terms of Reference, p. 3 of 8.

the 750 MW interconnection are \$86 million and the costs of Bipole III are \$259 million - totaling \$831 million for that year.¹⁸⁵

To partially offset those \$831 million of 2025 in-service costs, Manitoba Hydro forecasts net export revenues (net of fuel and power purchases and incremental water rentals) of approximately \$600 million.¹⁸⁶

The resulting shortfall of \$231 million is to be recovered from domestic ratepayers. Additionally, the costs of, and the resulting domestic revenue reductions due to enhanced DSM programs will become the responsibility of the domestic ratepayers.

On a cumulative basis from 2016 to 2037, (the years Manitoba Hydro has firm export contracts) the gross export revenues of \$17.0 billion are reduced to \$10.5 billion by the costs of exports (fuel and power purchases and incremental water rental fees). The cumulative costs of Keeyask, the 750 MW interconnection and Bipole III over the same period are approximately \$14.4 billion. The resulting shortfall of \$3.9 billion, together with costs for enhanced DSM and the related reduction in domestic revenues, will be added to ratepayer obligations.¹⁸⁷

Morrison Park noted the relationship between Manitoba Hydro's capital and operating costs, and its export prices and revenues. They stated that the long-term fixed contract prices are not related to Manitoba Hydro's cost of production, but rather to what the counterparty's alternative cost of energy might be, which is typically gas or coal-fired generation. According to Morrison Park, Manitoba Hydro is producing a fundamentally different product with different risks than the gas-fired generation developers in MISO, but is obtaining prices that are structured to reimburse a gas-fired developer for the risks it is taking.¹⁸⁸

6.6.0 Conclusions of the Panel

Long-Term Export Sales

Long-term export sales at premium prices underpin the business case of Manitoba Hydro's Preferred Development Plan and many of its alternatives. "Surplus by design" as a business strategy requires the assurance that Manitoba Hydro has access to markets and can sell its surplus capacity at favourable prices, for decades to come.

¹⁸⁵ Exhibit MH-211.

¹⁸⁶ Exhibit MH-104-12-7.

¹⁸⁷ Exhibit MH-211 and Exhibit MH-104-12-7.

¹⁸⁸ Transcript pp. 7379-81.

Manitoba Hydro's primary export market lies in MISO, particularly in Minnesota and Wisconsin. There does not appear to be a substantial Canadian market for Manitoba Hydro's exports. The reality is that Manitoba Hydro is reliant on a single market and dependent on the circumstances of that market, in which it is a price taker.

Based on the Panel's and La Capra's review of Manitoba Hydro's bilateral firm contracts, the Panel accepts the quantification of Manitoba Hydro's contracted dependable capacity and energy revenues as well as the contracted surplus energy revenues as \$6.9 billion. However, the Panel notes that diversity revenues are not guaranteed revenues as the counterparty has no obligation to purchase any diversity energy.

The Panel is concerned that Manitoba Hydro only has export contracts with terms of 10 to 15 years, and no contracts extend past 2036. This is less of a concern if only Keeyask is built, since domestic load and the existing signed contracts are expected to consume Keeyask's dependable output prior to 2036. The Panel is concerned with the risk that future export contracts may not attract the premium pricing that Manitoba Hydro assumes. These premium prices are also assumed in the economic and financial analyses of the Conawapa Project.

Export Price Forecasts

Manitoba Hydro's electricity export price forecast is optimistic. Manitoba Hydro bases its forecast of opportunity sales and future long-term firm contracted sales on its electricity price forecast. If the export price forecast is too high, then Manitoba Hydro will not realize the anticipated export revenues and domestic ratepayers will be required to pay higher rates to make up the shortfall.

Carbon pricing may have a significant impact on the North American energy sector including MISO market prices. To the extent Manitoba Hydro's export price forecast includes a 'carbon premium', those export revenue forecasts will be overly optimistic if such a carbon premium does not materialize when forecasted. If a more robust carbon regime materializes, the results would be more favourable to Manitoba Hydro. The uncertainty as to carbon pricing adds to the risk facing Manitoba Hydro and its ratepayers.

Dependable vs. Opportunity Sales

The Panel does not share Manitoba Hydro's view that it can sell all of its surplus dependable energy and capacity as long-term firm contracted sales at premium prices. In the absence of long-term firm U.S. MISO bi-lateral sales, Manitoba Hydro will have to

rely on opportunity sales, at market prices. Accordingly, the Panel considers Manitoba Hydro's forecast of future firm export revenues to be optimistic.

New Generation and Transmission

The Panel evaluated the in-service costs (financing, depreciation, operating and maintenance) of Keeyask, Conawapa, Bipole III and the 750 MW interconnection. The Panel concludes that the firm and opportunity revenues from Keeyask are not sufficient to pay all of the in-service costs of Keeyask, the 750 MW interconnection, and Bipole III. As a result, domestic customers are required to make up the shortfall through rates. Keeyask is required by domestic customers after 2024. Until then, the export revenues will continue to defray some of the in-service costs and mitigate some of the risk associated with the project.

The Panel considered the new export contract with Minnesota Power. The Panel notes that there is no contractual obligation on the part of Manitoba Hydro to construct Keeyask in order to serve the Minnesota Power 250 MW contract. Furthermore, with its enhanced DSM measures, Manitoba Hydro may not need the power from Keeyask to serve this contract until the mid- to late-2020s. However, as the Panel concludes in the Economic Evaluation Chapter, it is still more economic to construct Keeyask for a 2019 in-service date than to defer construction.

Manitoba Hydro stated that Minnesota Power is justifying the 750 MW interconnection to its regulator by highlighting the benefits of the additional wind storage that will result from new hydraulic generation being constructed by Manitoba Hydro. The Panel sees little risk in Minnesota Power backing away from the 750 MW interconnection because the Energy Exchange Agreement provides significant wind storage benefits in Manitoba Hydro's system. While the Panel does not expect Minnesota Power to back away from its application to build the 750 MW transmission line, the Panel notes there is risk that the Minnesota Public Utilities Commission may not approve the project. This risk is discussed in Chapter 10.

Manitoba Hydro asserted that the other significant export contract, the WPS 308 MW sale, is "tied to Conawapa." There is a termination clause that allows WPS and/or Manitoba Hydro to cancel the contract if the 4th unit of Conawapa is not commissioned by 2031. With Manitoba Hydro's enhanced DSM measures, the WPS contract could be served from Keeyask and existing hydraulic resources. While the Panel recognizes that WPS could terminate the 308 MW sale contract if Conawapa is not constructed, it also expects WPS would want to avail itself of Manitoba Hydro's exported energy, regardless

of whether it is generated by Conawapa or Manitoba Hydro's other hydroelectric stations.

Summary Observations

The Panel observes that:

- MISO market price forecasts may be too high;
- Carbon prices may not materialize, lowering the forecast market price by 20-25%. Alternatively, if the carbon market exceeds forecasts, the value of Manitoba Hydro's exports may be enhanced;
- With decreased MISO market prices, both opportunity and future firm contract prices and revenue will be lower;
- Manitoba Hydro is unlikely to be able to sell 100% of its dependable energy under long-term firm contracts at premium pricing; and
- Other technology risks such as distributed generation achieving grid parity could result in dramatic decreases in market prices.

If export revenues are less than Manitoba Hydro forecasts, domestic customers will be expected to make up the shortfall. While Manitoba Hydro forecasts rate increases for the next twenty years, export revenues short of those expectations may force the rate increases to be greater. Since more of the output of Keeyask is sold under firm contract, including the WPS 308 MW contract, the Panel sees less risk of disappointing export revenues from Keeyask compared to Conawapa.

Considering the uncertainty of future export revenues, specifically those that flow from Conawapa, all of these factors add up to heightened and unacceptable risk associated with the Preferred Development Plan.

The Panel considers it critical that Manitoba Hydro achieve firm bilateral sales, at premium prices, for its non-contracted surplus energy. Failure to do so exposes the domestic ratepayer to additional rate increases.

7.0.0 Cost of New Generation and Transmission

7.1.0 Introduction

The need to develop and construct new generation resources underpins all of Manitoba Hydro's plans and strategies. To meet that need, Manitoba Hydro considered a range of alternative resource options, including hydroelectric generating stations, natural gas-fired generation stations and wind farms. All alternatives rely on new transmission infrastructure. The hydroelectric alternatives rely on the northern HVDC corridor and interconnection to the United States.

The alternatives differ in the magnitude of their capital costs, and expected useful life. The magnitude of the required capital investments creates risks of a nature and extent that will have a significant impact on Manitoba Hydro, Manitoba ratepayers, and the Government of Manitoba.

Given the importance associated with the costs and risks in constructing new generation, the Terms of Reference directed the Panel to consider a number of specific questions. In particular, the Panel was asked to assess the reasonableness of construction costs. This chapter examines Manitoba Hydro's construction cost projections and management.

This chapter begins with a consideration of the construction requirements and costs associated with the Keeyask and Conawapa Projects. It examines the estimated costs, the contracting procedures and the construction management requirements and risks. The chapter then proceeds to look at the transmission elements to the Preferred Development Plan. Finally, the chapter considers the construction costs and roles of gas, wind and solar generation in Manitoba Hydro's future.

7.2.0 Alternative Plans and New Generation Requirements

Each of the proposed alternative plans has different combinations of generation supply components, including hydropower, thermal gas-fired generation (both simple cycle gas turbines and combined cycle gas turbines), and wind power. In addition, different plans have different transmission requirements and components. These requirements and options are summarized in the Table below. They include the 15 plans as originally filed by Manitoba Hydro, along with two additional plans prepared and presented by La Capra Associates.¹⁸⁹

¹⁸⁹ Manitoba Hydro NFAT Submission, Chapter 9, p. 12. Exhibit LCA-45, pp. 29-39.

Table 9 List of New Resource Components by Development Plan

#	Plan Name	New Resource Components							
		Keeyask	Conawapa	SCGT	CCGT	Wind	Solar	750MW	250MW
1	All Gas			x	x				
2	K22/Gas	x		x	x				
3	Wind/Gas			x	x	x			
4	K19/Gas24/250MW	x		x	x				x
5	K19/Gas25/750MW	x		x	x			x	
6	K19/Gas31/750MW	x		x	x			x	
7	SCGT/C26		x	x					
9	CCGT/C26		x		x				
9	Wind/C29		x			x			
10	K22/C29	x	x						
11	K19/C31/250MW	x	x						x
12	K19/C31/750MW	x	x					x	
13	K19/C25/250MW	x	x						x
14	K19/C25/750MW (WPS Sale and Inv.)	x	x					x	
15	K19/C25/750MW	x	x					x	
16	LCA All CCGT				x				
17	LCA No New Generation			x	x			x	

7.3.0 Hydropower Projects: Keeyask and Conawapa

Manitoba Hydro's Preferred Development Plan and its alternatives include two hydropower projects (Keeyask and Conawapa), a new 750 MW U.S. transmission interconnection, and upgrades to Manitoba Hydro's northern alternating current (AC) transmission system. Each consists of a number of components, which are further described below.

7.3.1. Overview of the Keeyask and Conawapa Projects

The Keeyask Project has three components: the 695 MW generation station, the related Keeyask infrastructure project, which is currently nearing completion, and the Keeyask transmission project. Collectively, the Keeyask Project is expected to take 8 years to

construct. The infrastructure work began in 2012 and the generation stations and transmission element are scheduled to begin in July 2014 depending on decisions and approvals by the Government of Manitoba and the Government of Canada.

The first generation units are planned to be in-service in 2019, and all units in operation in 2020. Keeyask will add 3,000 GWh of dependable energy to Manitoba Hydro's system.

The Conawapa Project consists of two elements: the 1,495 MW generation station and related Conawapa transmission outlet project. Additionally, Manitoba Hydro will undertake a north-south transmission system upgrade to the existing northern 230 kV alternating current (AC) system and the existing HVDC transmission system. This upgrade is only required if Conawapa is developed.

The generation component is expected to take 9 years to complete from a planned start in 2019. In the NFAT Submission, Manitoba Hydro indicated a 2026/27 in-service goal with the first of 10 generating units for service in 2026 and the remaining units in production in 2027.

The north-south transmission upgrades will be completed coinciding with the in-service date of the last Conawapa units. Conawapa will add 4,650 GWh of dependable energy to Manitoba Hydro's system.

7.3.2. Construction Costs of Keeyask and Conawapa Projects

In the course of the hearing, Manitoba Hydro advised the NFAT Panel of capital cost estimate updates for Keeyask and Conawapa. As illustrated below, the capital cost estimates were increased on March 10, 2014 to \$6.5 billion from \$6.2 billion for the Keeyask Project and to \$10.7 billion from \$10.2 billion for the Conawapa Project.¹⁹⁰

¹⁹⁰ Exhibit MH-95, pp. 101, 103. See also 2009 Estimate: CEF09-1, November 2009.

Table 10 Keyeyask and Conawapa Construction Budget Updates, 2009-2014

Project	Capital Cost Updates	Base Costs (includes sunk costs)	Interest + Escalation	Total Costs
Keeyask	2009 Estimate (2019 ISD)	n/a	n/a	3.7
	NFAT Submission (2019 ISD)	4.63	1.59	6.2
	March 2014 Update (2019 ISD)	4.84	1.65	6.5
Conawapa	2009 Estimate (2022 ISD)	n/a	n/a	4.9
	NFAT Submission (2025 ISD)	6.39	3.90	10.2
	NFAT Submission Update (2026 ISD)	6.39	4.05	10.4
	March 10, 2014 Update (2026 ISD)	6.44	4.22	10.7

Since 2009, the capital costs of Keeyask and Conawapa have increased materially, with the Keeyask capital cost projection having increased by 75% and the Conawapa capital cost projection by over 100%.

Manitoba Hydro's current "high" capital cost estimate is \$7.2 billion for the Keeyask Project (15% above its current cost estimate) and \$12.5 billion for the Conawapa project (17% above its current cost estimate).¹⁹¹ The Panel notes that, in March 2014, Manitoba Hydro estimated sunk costs by June 2014 for the Keeyask Project of \$1.2 billion and \$.4 billion for Conawapa. However, Manitoba Hydro's witness Dr. Borison cautioned against assuming that past increases were a predictor of future cost increases. In response to concerns that Keeyask may experience similar cost increases as Wuskwatim, Manitoba Hydro noted that Wuskwatim costs only increased by 10% from the point in time where Wuskwatim had reached a similar stage of development, project definition, and contracting as Keeyask.¹⁹²

In their review of similar dam construction projects, Knight Piésold found that large hydropower plants such as Keeyask and Conawapa typically range from \$2 Million/MW installed to \$10 Million/MW installed. The proposed installed costs of the Keeyask Project is \$9.9 Million MW, which is at the upper level of project norms.

7.3.3. Construction Contingencies and Reserves

Manitoba Hydro's "reference" capital cost estimates are based on a P50 contingency level, meaning there is an equal probability of costs being lower or higher. Manitoba Hydro's "high" capital cost estimates are determined by adding a Management Reserve to the contingency. The Management Reserve consists of a labour reserve, which is

¹⁹¹ Exhibit MH-161, pp. 2-3.

¹⁹² Exhibit MH-204, p. 69.

designed to account for labour productivity problems, as well as an escalation reserve, which is designed to account for annual escalation costs being higher than the 2.5% budgeted by Manitoba Hydro.¹⁹³

Knight Piésold reviewed Manitoba Hydro's approach to contracting and risk management. It found that Manitoba Hydro was following best practices. However, Knight Piésold also suggested that a more risk-averse decision maker would use a P80 cost estimate, rather than a P50 cost estimate¹⁹⁴, as well as apply a composite hydropower escalation rate of 3.1% to 3.4% rather than the 2.5% applied by Manitoba Hydro.¹⁹⁵ A P80 cost estimate means that there is only a 20% chance of the project being over budget and, according to Manitoba Hydro's estimate, would increase the required contingency for Keeyask by \$321 million.¹⁹⁶

Based on their knowledge of similar projects, Knight Piésold expressed concerns about the risks associated with labour shortages, construction delays given terrain and northern climate, and concrete work productivity. As a result, Knight Piésold concluded that the "amount of contingency carried for the two generation projects (Keeyask and Conawapa) could be considered insufficient depending on the use made of the capital cost estimates."¹⁹⁷ A worst-case capital cost scenario might see costs higher than the \$7.2 billion for Keeyask currently forecast by Manitoba Hydro for its "high" scenario.

7.3.4. Keeyask Construction Contract

In its scope of work, Knight Piésold was asked to review the cost estimates, contracting practices, and the contract provisions. They undertook to determine the extent practices were appropriate, costs were reasonable, and measures were in effect to address changes or increases in construction costs. The Panel focused on Keeyask-related contracting given the immediate nature of decisions on whether to proceed with construction in July 2014, and the fact that Conawapa construction contracts had not yet been entered into.

Knight Piésold assessed Manitoba Hydro's costs estimates and contracts. They discussed questions about documentation and procedures with Manitoba Hydro staff. They then used their experience and past work to assess these practices against industry best practices and similar hydropower construction projects. Knight Piésold reported to the Panel that many of Manitoba Hydro's practices and procedures were

¹⁹³ Manitoba Hydro NFAT Submission, Chapter 15, p. 39.

¹⁹⁴ Exhibit KP-4, p.57.

¹⁹⁵ Transcript, p. 6904.

¹⁹⁶ KP/MH II-26(a).

¹⁹⁷ Exhibit KP 3-1, p. i.

reasonable and appropriate, relative to industry best practice. Knight Piésold supported Manitoba Hydro using an Early Contractor Involvement process to obtain input from the chosen contractor in order to refine the design, construction techniques, schedule, and risk sharing.¹⁹⁸ Knight Piésold told the Panel that Manitoba Hydro had made the appropriate choices in the various Keeyask Project contracting efforts. The contracting choices were designed to secure the most cost effective contracts.¹⁹⁹

Manitoba Hydro submitted that the risk associated with the Keeyask construction is somewhat addressed given that 80% of the construction contracts have now been negotiated. However, this only partially mitigates cost risk. The Keeyask general civil contract is a cost-reimbursable contract, not a fixed price contract. This leaves the contract vulnerable to cost escalations as a result of: quantity risk, especially in areas where quantities may have been underestimated; escalation to the contractor's cost factors due to labour productivity or labour costs; escalation in the cost of supply and equipment; and challenges related to adverse weather conditions.

No similar contracts exist with respect to the Conawapa Project.

7.4.0 Transmission

7.4.1. Overview of Transmission Components

Manitoba Hydro's transmission system consists of numerous transmission lines that assist in delivering power to its Manitoba customers, as well as supporting both exports and imports to and from neighbouring power systems in Saskatchewan, Ontario and the United States.

The system has two major components: the Alternating Current ("AC") transmission system and the High Voltage Direct Current ("HVDC") system. The existing HVDC system consists of Bipoles I and II and connects to the Northern Collector System, which consists of several short transmission lines connected to the northern hydro dams.

The AC transmission system forms the bulk of the length of the transmission lines in Manitoba, consisting of 7,200 km of lines. This system brings power from generating stations to dozens of electrical stations around the province.

With regard to other provinces and the United States, Manitoba Hydro currently has five cross-border transmission interconnections with Saskatchewan, three interconnections

¹⁹⁸ Exhibit KP-4 p.14.

¹⁹⁹ Exhibit KP-4 p. 14.

with Ontario and four interconnections with the U.S. The current interconnection capacity is:²⁰⁰

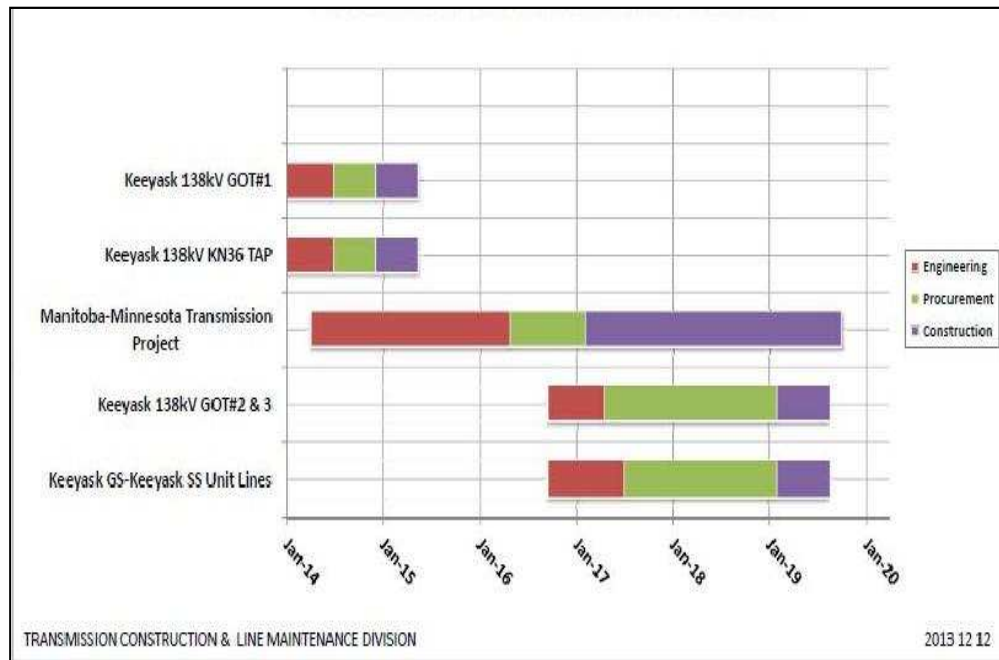
Table 11 Manitoba Hydro Interconnection Limit and Capacities

Interconnections	Firm Export Schedule Limit	Firm Import Transfer Capacity
United States	1,950 MW	700 MW
Ontario	200 MW	0 MW
Saskatchewan	150 MW	0 MW
Total	2,300 MW	700 MW

7.4.2. Proposed Transmission Connections

In its Preferred Development Plan, Manitoba Hydro identified the following transmission components: Keeyask Transmission Project; Conawapa Transmission Project; North-South Transmission System Upgrade Project; and the Manitoba-Minnesota Transmission Project. These are to be constructed in accordance with the following Manitoba Hydro timetable:²⁰¹

Figure 10 Transmission Engineering, Procurement and Construction Timetable, 2014-2020



²⁰⁰ Manitoba Hydro NFAT Submission, Chapter 5, p.16.

²⁰¹ Exhibit KP-3-1, p. 79.

The Conawapa Transmission Project and North-South Transmission System Upgrade Project are scheduled to be completed by 2027.

Keeyask Transmission Project

The Keeyask Transmission Project will connect the Keeyask Generating Station to the existing Radisson Converter Station, and involves the construction of a new switching station as well as approximately 39 km of transmission line. The total cost estimate, in 2012 dollars, is projected at \$156.7 million.²⁰² With escalation and interest, the in-service cost is estimated at \$203 million.²⁰³ Power Engineers examined the cost estimate and found it to be reasonable in light of several construction difficulties identified for the line.

Conawapa Transmission Outlet Project

The Conawapa Transmission Outlet Project will connect the Conawapa Generating Station to the newly constructed Keewatinow Converter Station by means of a 7 km transmission line. The total cost estimate, in 2012 dollars, is projected at \$10 million.²⁰⁴ With escalation and interest, the in-service cost is estimated at \$14 million.²⁰⁵

North-South Transmission System Upgrade

Although all of Conawapa's power can be transmitted from northern Manitoba to southern customers on Manitoba Hydro's high-voltage direct-current (HVDC) transmission system (including Bipole III, which is expected to be constructed by the time Conawapa enters service), Manitoba Hydro has identified reliability issues with respect to such an arrangement. To improve reliability, Manitoba Hydro proposes to upgrade the existing northern 230 kV alternating current (AC) system and existing HVDC transmission system, including a split of the northern Bipole system and placing one or more units of the Kettle Generating Station from the HVDC system onto the AC system. This will see the overall system usage rebalanced.

Together, these upgrades are referred to as the North-South Transmission System Upgrade Project. The project would have an in-service date coinciding with that of the last Conawapa unit. It would only be constructed if Conawapa proceeds. The total cost, in 2012 dollars, is estimated at \$340 million. With escalation, the total in-service cost is estimated at \$498 million.²⁰⁶ Power Engineers examined the cost estimate and found it to be reasonable. However, Power Engineers also identified a possible additional cost

²⁰² Exhibit MH-95, p. 78.

²⁰³ Exhibit PE-3, p.3.

²⁰⁴ Exhibit MH-95, p.84.

²⁰⁵ Exhibit PE-3, p.5.

²⁰⁶ Exhibit PE-3, p.6.

of \$39 million to enhance Bipole III converters to increase Bipole III capacity by 300 MW.²⁰⁷

Manitoba-Minnesota Transmission Project

The proposed U.S. interconnection consists of a new single-circuit 500 kV AC transmission line originating from Dorsey Station, northwest of Winnipeg, running south around Winnipeg, connecting to the Riel Converter Station, and then continuing in a southeast direction toward the international border. The U.S. portion of this interconnection, called the Great Northern Transmission Line, will terminate at a new 500 kV substation adjacent to the existing Blackberry substation in Minnesota, located approximately 100 km northwest of Duluth, Minnesota. The approximate total length of the 500 kV transmission line between the Dorsey and Blackberry substations is 600 km. The Manitoba-Minnesota portion of the Transmission Project in-service cost is estimated to be \$350 million.²⁰⁸

Great Northern Transmission Route

The Manitoba-Minnesota Transmission Line will connect at the U.S. border with Minnesota Power's proposed Great Northern Transmission Line with an in-service date of 2020. The total cost in 2013 U.S. dollars is estimated at \$507 million.²⁰⁹ Manitoba Hydro will be responsible for some portion of the capital and ongoing operating costs associated with the U.S. portion of the transmission line. During the hearings, Manitoba Hydro updated the Panel on the costs and cost sharing arrangements.

Minnesota Power will have funding responsibility (33%) for the transmission needed for the 250 MW Power Sale Agreement. Manitoba Hydro will fund the remaining 67% share for its 49% ownership position plus 18% scheduling fee. This is paid to Minnesota Power to cover increased revenue requirements associated with the additional 133 MW of capacity that it will own above the 250 MW Sales Agreement. Manitoba Hydro is in discussions to sell a portion of their 49% share.²¹⁰

7.4.3. The Role and Value of Transmission Export and Import Capacity

In the course of the hearings, the Panel learned of the importance of new transmission to the United States with regard to enhancing system reliability and providing greater opportunities for both exporting and importing electricity.

²⁰⁷ Exhibit PE-3, p.6.

²⁰⁸ Manitoba Hydro NFAT Submission, Chapter 2, p. 59.

²⁰⁹ Exhibit MH-95, p. 81.

²¹⁰ Exhibit MH-204, pp. 103-104.

In its Preferred Development Plan, Manitoba Hydro outlined the potential benefits realized by the addition of the new hydro resources and the new U.S. interconnection. In its view, the interconnections provide significant reliability benefits in terms of sharing of generation contingency reserves, sharing of capacity resources due to load diversity, importation of energy during drought conditions or extreme supply loss in Manitoba, and the ability to supply cross-border load when this load is isolated from its system.

Transmission has economic value. It provides the means to export surplus hydropower. There are times during the peak winter demand period when it may be economically beneficial to import lower-cost resources from outside of Manitoba rather than use Manitoba Hydro's own thermal resources.

Several individuals testified that the development of new transmission connections with the United States will be a strategic asset. They noted that transmission to facilitate imports could have the effect of changing the development plan options and pathways. Greater imports could defer the need for new resource development, especially hydropower facilities. For several interveners, such as the Green Action Centre, the construction of the 750 MW transmission line has demonstrated value.²¹¹

In its report on transmission, La Capra Associates identified that the addition of Keeyask in 2019, the new interconnection line in 2020, and Conawapa in 2026 all affect the total energy exported by Manitoba Hydro. They concluded that there is a 3.2% increase in total exports when Keeyask is placed in service and a 38% increase when the new line is completed. Lastly, there could be a 30% increase in total exports in 2026 when Conawapa enters operation.²¹²

The new interconnection will, therefore, help in optimizing the new capacity from Keeyask and perhaps Conawapa in future years. The majority of the benefits will appear after the construction of Conawapa where the total exports will be around 14,000 GWh, almost 50% higher than the average over the 2009-2012 period. Still, the addition of the new interconnection results in a significant increase in total firm sales in 2020. The increase in firm sales is mostly associated with the initiation of the new Minnesota Power Sales Agreement and the Wisconsin Public Service Agreement.

7.5.0 Manitoba Hydro's Proposed Generation Alternatives

In its NFAT Submission, Manitoba Hydro outlined a number of generation options and opportunities. Some are described as long-term opportunities for future consideration.

²¹¹ Exhibit GAC-27, p. 23.

²¹² Exhibit LCA-11, pp. 65-66.

Others were assessed as being not effective or relevant to Manitoba's power requirements. Still others, such as the Keeyask Project, are presented in detail and require immediate decision-making, leading to impending development and construction. The following Table summarizes the capital and per unit energy costs as identified by Manitoba Hydro:²¹³

Table 12 Comparison of Installed Capital Cost and Per Unit Costs Based on Utility Scale Generation in Manitoba

Technology	Installed Costs \$/kW	Energy Cost \$/MWh	Cost Trend
Energy Storage	300 – 11,000	10 – 360	Decreasing
Solar Photovoltaic	3,700 – 5,000	190 – 200	
Wind	1,600 – 7,600	60 – 210	
Biomass	2,000 – 5,800	100 – 150	Stable
Solar Thermal	3,500 – 7,500	140 – 190	
Enhanced Geothermal	25,000 – 37,500	290 – 440	Increasing
Hydroelectric	3,800 – 21,000	60 – 290	
Hydrokinetic	7,00 – 9,500	160 – 620	
Nuclear	3,500 – 7,000	90 – 120	

During the hearings, the Panel heard a great deal from its Independent Expert Consultants and the Interveners about the relative merits of gas turbines as a resource option, and the emerging importance of solar and wind power generation.

7.5.1. Thermal Gas Generation

Thermal gas generation options play a prominent role in Manitoba Hydro's planning options. An All Gas option was used as the reference case. All of the 15 Alternative Plans entail the construction on one type or other of gas turbines at some point in the future.²¹⁴ Manitoba Hydro examined both Simple Cycle Gas Turbines (SCGT) and Combined Cycle Gas Turbines (CCGT). While SCGTs are lower capital cost, they are less efficient than CCGTs, more at risk to fuel price changes, and emit more greenhouse gases. CCGTs are more efficient, use less fuel, emit fewer greenhouse gases, and are better suited to either intermediate or baseload service because of their higher capital cost.²¹⁵

²¹³ Manitoba Hydro NFAT Submission, Appendix 7.1, p. 17.

²¹⁴ Manitoba Hydro NFAT Submission, Chapter 9, Table 9.3.

²¹⁵ Manitoba Hydro NFAT Submission, Appendix 7.2, pp. 26-30.

Knight Piésold examined the capital costs of gas turbines: SCGTs cost \$0.77 million per MW of installed capacity and CCGT turbines cost \$1.30 million per MW.²¹⁶ The various Plans required differing numbers of types of turbines over the 78-year period. The All Gas Plan requires eight SCGTs and CCGTs.²¹⁷

La Capra Associates provided the Panel with two additional alternative plans, including one with an all-gas scenario. It involved only CCGTs rather than mix of CCGT and SCGTs. This additional option was seen to be similar to Manitoba Hydro's All Gas reference case. The No New Generation Plan included the 750 MW interconnection with the U.S., enhanced DSM, increased imports from the U.S., and new gas turbines as required once DSM and imports could no longer address domestic load growth. The No New Generation plan compared favourably to the All Gas Plan on economics, and had better expected values than the Preferred Development Plan.²¹⁸

There are also socio-economic and environmental considerations of gas as a resource option. Gas generation might offer more distributed socio-economic benefits throughout Manitoba, and employment advantages might eventually equal those of northern hydropower projects. However, the benefits to northern and aboriginal communities associated with hydropower options would be lost. Moreover, there are serious environmental impacts: the Clean Environment Commission estimated that a comparably sized natural gas plant would produce as much greenhouse gas in 177 days as the Keeyask Generation Project will produce in 100 years.²¹⁹

7.5.2. Solar Power Generation

Solar photovoltaic power, or solar PV, was once an expensive option, and unthinkable from a resource planning perspective. However, a combination of technological advances and economies of scale have dramatically altered the outlook for solar PV. Solar power is currently being supplied by some electrical utilities using large "solar farms," as well as through roof-top panels by individual residential and commercial users.

During the hearings, the Panel heard from several parties about the new promise of solar power, given its forecasted cost decline and its implications for grid parity. Grid parity is that point at which, from homeowner or business perspectives, the installed cost of rooftop solar PV becomes less expensive, on an annualized basis, than the cost of electricity supplied by the grid. In the view of Mr. Dunsky, solar PV costs have been

²¹⁶ Exhibit KP 3-1, p. 51.

²¹⁷ Manitoba Hydro NFAT Submission, Chapter 8, pp. 19-22.

²¹⁸ Exhibit LCA- 45, p. 24.

²¹⁹ Exhibit PUB-69, p. 61.

declining sharply (10% per year on average since 2006) and are expected to continue to do so in the near future. Because of these declines, solar PV has begun to achieve grid parity in several U.S. states. Various forecasts now expect grid parity to be reached for a large share of worldwide electricity demand by 2020.²²⁰

In its NFAT Submission, Manitoba Hydro identified the declining costs of solar PV through 2020 for residential and utility systems. Manitoba Hydro anticipates residential system costs declining to \$1.12/watt by 2020.²²¹ Given Manitoba's annual sunshine (global solar radiation in Winnipeg based on Natural Resources Canada data), Mr. Dunskey estimates residential rooftop solar PV costing approximately 8¢/kWh by 2020.²²² According to Mr. Dunskey, if this cost forecast is correct, then given Manitoba Hydro's own projected rate increases, residential grid parity could be reached in Manitoba well before the end of the current planning period. Moreover, Mr. Dunskey states that Manitoba Hydro's own projections for utility-scale PV costs are even more dramatic and are forecast to cost \$0.65/watt by 2020. If this is accurate, the cost of utility-scale solar in Manitoba would drop to approximately 5¢/kWh by 2020, well below the projected levelized cost of Conawapa.²²³

Knight Piésold also noted that capital costs for solar PV have reduced by a factor of 10 over the last three decades and have experienced a 22% reduction in the last three years. Manitoba Hydro will have to factor these price decreases into its future integrated resource plans.²²⁴

7.5.3. Wind Power

Manitoba Hydro currently purchases all of the output of the privately owned St. Leon and St. Joseph wind farms, which have a combined maximum hourly generation capacity of 258 MW²²⁵. Wind power generation was also part of two of Manitoba Hydro's alternative development plans. Under the Wind/Gas Plan, new wind capacity would come into service in 2022/23, supported by new gas capacity but no new hydro capacity. This Plan would encompass generic 65 MW wind farms: two built per year from 2022 through 2024, and one per year from 2027 through 2047 for a total of 1,755 MW. Under the Wind/C26 plan, new wind capacity would be installed in 2022/23, along with Conawapa coming into service in 2026/27. This Plan would involve a nominal wind capacity of 390 MW.²²⁶

²²⁰ Exhibit CAC-19, pp. 35-39.

²²¹ Manitoba Hydro NFAT Submission, Appendix 7.1, pp. 43-44.

²²² Exhibit CAC-19, p. 39.

²²³ Exhibit CAC-19, p. 39.

²²⁴ Exhibit KP-3-1, p.57.

²²⁵ Manitoba Hydro NFAT Submission, Chapter 5, p. 6.

²²⁶ Manitoba Hydro NFAT Submission, Chapter 8, p. 19.

However, for purposes of its resource planning, Manitoba Hydro considers wind as an intermittent resource that is only available when the wind is blowing. Manitoba Hydro also assumed that wind power has a reliable winter peak capacity of zero, given its intermittent nature and the inability of wind generators to reliably function in temperatures below -30°C .²²⁷ Manitoba Hydro calculated that the Levelized Cost of Electricity²²⁸ (LCOE) of wind was \$82/MWh (2014\$) as compared to \$60/MWh for Keeyask and \$67/MWh for Conawapa.²²⁹

Manitoba Hydro concluded that wind generation was significantly more expensive than its Preferred Development Plan. As a result, Manitoba Hydro stated that “wind generation as a major generation supply in Manitoba was determined to be un-economic at this time.”²³⁰ A number of the Independent Expert Consultants and the Interveners disagreed with Manitoba Hydro’s conclusions based on the following three factors.

Wind Power Capital Costs and Trends

In its NFAT Submission, Manitoba Hydro identified a reference case capital cost of \$2,100/kW for the wind turbines, with an additional \$300/kW for transmission upgrades.²³¹ This assumption was also addressed by Knight Piésold, which suggested a base cost of \$1,800/kW (excluding transmission).²³² La Capra Associates concluded that average capital costs were about \$1,750/kW in 2012 including transmission interconnection costs.²³³ In its assessment, Power Advisory recommended \$1,940/kW as a reasonable estimate of wind capital costs in 2012 including transmission.²³⁴

Manitoba Hydro assumed that wind capital costs would neither increase nor decrease in real terms. To the contrary, Knight Piésold, La Capra Associates, and Power Advisory all reported that wind capital costs are expected to decline.

Construction Period and Operating Life

Manitoba Hydro’s LCOE calculations suggest a three-year construction period, which Power Advisory’s research suggested was reasonable. However, Manitoba Hydro assumed that 97% of the wind project construction costs will have been incurred by the second year. Power Advisory disagreed, suggesting that 5% of total costs are incurred

²²⁷ Manitoba Hydro NFAT Submission, Chapter 5, p. 6.

²²⁸ Manitoba Hydro NFAT Submission, Appendix 7.1 p. 75.

²²⁹ Manitoba Hydro NFAT Submission, Chapter 7, p. 25, 34.

²³⁰ Manitoba Hydro NFAT Submission, Appendix 14.1, p. 24.

²³¹ Exhibit KP-3-1, p. 47.

²³² Exhibit KP-3-1, p. 49.

²³³ Exhibit LCA-45, p. 35.

²³⁴ Transcript, p.9668, 9829.

in the first year and 35% in the second year.²³⁵ Manitoba Hydro's assumption increases the LCOE for wind because the costs are being evaluated on a net present value basis.

In its NFAT Submission, Manitoba Hydro assumed that new wind projects would have a useful life of 20 years.²³⁶ La Capra Associates identified 25 years and Power Advisory found in discussions with wind power developers that 25 years is a common operating life for wind turbines.²³⁷ Power Advisory noted that the St. Leon wind project has a contract term with Manitoba Hydro for 25 years, while the St. Joseph wind project has a 27 year contract term. Power Advisory also noted that new wind turbines have 25 year warranties. The shorter project life assumed by Manitoba Hydro negatively impacts the economics of wind projects.

Wind Capacity Factor

Manitoba Hydro assumed a wind capacity factor of 40%, "consistent with recent experience for wind generation resources in Manitoba having 80 metre hub heights."²³⁸ La Capra Associates questioned this assumption. It noted recent projects in the region with an average capacity factor of 42% and assumed a 43% capacity factor in its sensitivity analysis.²³⁹ Power Advisory agreed with Manitoba Hydro's assumption of a 40% capacity factor, while pointing out a higher capacity factor may be appropriate for new projects with larger towers.²⁴⁰ Manitoba Hydro states that it assumes a Fixed O&M cost of \$39.55/kW-year in 2012 dollars.²⁴¹ Power Associates reported that this was consistent with its experience, but also noted that Manitoba Hydro used a higher cost of \$46/kW-year in its calculation of LCOE.²⁴²

7.6.0 Conclusions of the Panel

The actual construction cost of Keeyask will increase beyond Manitoba Hydro's currently projected capital cost of \$6.5 billion. Budgeting at least for Manitoba Hydro's "high" estimate of \$7.2 billion would be prudent.

This conclusion is not reached as a result of the history of past capital cost increases. The Panel accepts Manitoba Hydro's argument that the past is not necessarily a predictor of the future. Rather, the Panel bases its conclusion on its review of the Keeyask general civil contract, which is a cost-reimbursable contract that leaves a

²³⁵ Stevens, May 1, 2014 Transcript p.9669.

²³⁶ Exhibit GAC/MH, 1-010a.

²³⁷ Exhibit GAC-13, pp. 4-7.

²³⁸ Exhibit GAC/MH 1-004a.

²³⁹ Exhibit LCA-5-1, p.10.

²⁴⁰ Exhibit GAC-13, pp. 4-8.

²⁴¹ Manitoba Hydro NFAT Submission, Appendix 7.2, p. 327.

²⁴² Exhibit GAC-13, pp.4-9.

significant portion of cost risk with Manitoba Hydro. It would be a fallacy to assume that the contract provides anywhere near the same level of cost certainty as a fixed-price contract, which would be more expensive.

This is not a criticism of the Keeyask general civil contract or Manitoba Hydro's approach to contracting. The Panel is satisfied that Manitoba Hydro's approach to developing and negotiating the contract, as well as its approach to managing risk, has been appropriate to date. Rather, it reflects the general nature of a large infrastructure project with inherent risks that can be mitigated, but not avoided.

Since no similar contract exists for the Conawapa Project to date, and Conawapa's proposed in-service date is a full 12 years away, the Panel has little confidence in Manitoba Hydro's current control budget. While the Panel is satisfied that Manitoba Hydro followed proper cost estimating procedures, in the Panel's view the significant uncertainties associated with Conawapa make any current estimate a rough guess at best and a high risk at most.

The history of capital cost increases over numerous successive forecasts is of concern to the Panel. It therefore sees a need for greater cost accountability in the form of an annual accounting of construction costs to the Province of Manitoba, which would explain the reason for such increases, rather than simply filing a new Capital Expenditure Forecast.

With respect to Manitoba Hydro's construction cost estimates for transmission facilities, the Panel concludes that such estimates are reasonable and recommends that Manitoba Hydro be given approval to proceed with the construction of a 750 MW transmission interconnection to the United States for a 2020 in-service date.

This interconnection provides increased firm transmission access extending into Minnesota, provides important, increased reliability, and supports import and export of electricity. However, the Panel encourages Manitoba Hydro to sell a portion of its 49% stake in the Great Northern Transmission Line.

Given the Panel's recommendation to discontinue spending on Conawapa, the North-South Transmission System Upgrade will not be required.

The Panel does not believe that thermal gas generation provides a reasonable alternative, especially when considered against the future potential of solar and wind power. The Panel is very concerned about the environmental implications of gas generation as a baseload resource, especially with respect to Simple Cycle Gas Turbines that do not achieve the same efficiency as Combined Cycle Gas Turbines.

While future integrated resource planning will have to consider all resource options, the adverse environmental effects of gas generation will have to be thoroughly considered.

With respect to alternative generation technologies, the Panel concludes that Manitoba Hydro's cost estimates for wind are likely overstated. Given the rapid changes in pricing with respect to alternative generation technologies, especially wind and solar PV, Manitoba Hydro should include greater consideration of such technologies in its integrated resource planning. This analysis and planning must include consideration of potential future grid parity with respect to solar technology, and the likely impacts of such a scenario on load forecasts and expected revenues.

8.0.0 Economic Evaluation

8.1.0 Introduction

8.1.1. Types of Evaluations

Manitoba Hydro's NFAT Submission provides an economic and a financial evaluation of the Preferred Development Plan and the alternative development plans that Manitoba Hydro considered as future resource options. Both types of evaluations are ways to compare the different plans and provide information to aid decision making in choosing a plan. The economic evaluation compares the benefits and costs of the different plans from Manitoba Hydro's perspective in order to determine which plan provides the greatest economic benefit to the utility. The financial evaluation compares the costs and revenues associated with each plan to determine the impact on future customer rates and Manitoba Hydro's exposure to financial risk. In Manitoba Hydro's Multiple Account Benefit-Cost Analysis (MA-BCA) discussed in Chapter 11, the total social benefits and costs, as well as their distribution, are considered.

The Terms of Reference task the Panel with assessing "whether the Preferred Development Plan is justified as superior to potential alternatives that could fulfill the need." In doing so, the Panel is to consider "the reasonableness of the scope and evaluation of risks and benefits proposed to arise from the development" and the "economic risks of the Plan ... and alternative development strategies." The Terms of Reference further state that the Independent Expert Consultants engaged by the Panel must "critically examine whether the high level summaries filed by Hydro of Net Present Values and Internal Rates of Return which are derived from Commercially Sensitive Information reflect sound assumptions and calculations."²⁴³

This chapter examines Manitoba Hydro's economic evaluation of the Preferred Development Plan and alternatives. It also presents other economic evaluation metrics that the Independent Expert Consultants have used in their respective economic analyses.

8.1.2. Metrics

This chapter makes reference to different metrics in relation to the economic analysis: Net Present Value (NPV), Cumulative Present Value (CPV), Break Even/Payback, Internal Rate of Return (IRR), Ref-Ref-Ref, and Expected Value. Each of these metrics has a different meaning and provides a different view of the various development plans.

²⁴³ Exhibit PUB-2, pp. 2-4.

In its analysis, Manitoba Hydro compares the net benefits of alternative development plans to Plan 1 (the All Gas Plan).

Net Present Value (NPV) is a standard economic analysis tool representing the present value of the future stream of annual revenues and costs. Because people tend to place a higher value on income today compared to income in the future, the stream of net benefits over time must be “discounted” at an appropriate rate to reflect this time preference. Net Present Value thus allows for alternatives with different costs and revenues that occur at different times to be compared on an equivalent basis at a single point in time.²⁴⁴

Cumulative Present Value (CPV) examines how beneficial a plan is compared to a base case from the start of a study period to a certain point in time during the period. The Cumulative Present Value is the Net Present Value at a given time (and thus ignores the incremental value of a plan over future dates). The final year's Cumulative Present Value matches the 78-year Net Present Value metric used by Manitoba Hydro.

A Cumulative Present Value Analysis is useful because it provides an understanding of the path towards reaching the Net Present Value and the year when a plan breaks even on a present value basis when compared to the base case and other plans being evaluated, or the **Break Even/Payback**. It complements a Net Present Value analysis by providing information on how quickly an upfront investment pays off as it is discounted over time.²⁴⁵

Manitoba Hydro did not calculate the Cumulative Present Value for the various development plans. La Capra Associates, Inc. provided these calculations in its analysis for the Panel.

Internal Rate of Return (IRR) is another metric typically used to evaluate investments or development plans. The Internal Rate of Return of a plan is the interest rate at which the Net Present Value of the costs associated with a development plan equals the net present value of the plan's benefits. It calculates the average annual return earned over the length of the study period. Another way of describing the Internal Rate of Return is the discount rate that brings the Net Present Value to zero. In relation to the evaluation of the development plans, if a plan has a positive incremental Net Present Value compared to the base case, then the Internal Rate of Return will be greater than the discount rate that Manitoba Hydro used in the economic evaluation. Manitoba Hydro provided Internal Rates of Return in response to an Information request from the

²⁴⁴ NFAT Review, Manitoba Hydro Application, Chapter 9 p.3

²⁴⁵ Exhibit LCA-12, p. 9A-36.

Panel²⁴⁶, but did not perform an Internal Rate of Return analysis in the main NFAT Submission. La Capra developed the Internal Rates of Return for the alternative development plans by using the annual cash flows incremental to the All Gas Plan. The annual cash flows are the annual values that resulted from Manitoba Hydro's modeling results.

In Manitoba Hydro's economic analysis, Ref-Ref-Ref refers to reference, or most likely, conditions. Manitoba Hydro also provided analyses for varying conditions for high and low export and natural gas prices, capital costs, and interest or discount rates. The weighted average of all of the ranges of those factors is known as the Expected Value (EV). Expected Value is an alternative metric to the Ref-Ref-Ref metric.

8.2.0 Manitoba Hydro's Economic Evaluation

8.2.1. Economic Evaluation Parameters

In Chapter 9 of the NFAT submission, Manitoba Hydro conducted an economic evaluation of the Preferred Development Plan and its 14 alternative plans using the following parameters:

- A 78-year study period. The study period used in Manitoba Hydro's NPV analysis is 78 years in order to include the end of the service life of the longest-lived asset, the Keeyask and Conawapa generating stations., The first 35 years of analysis are based on a detailed evaluation of each plan while, for some plans, the results are extrapolated over the remaining 43 years.
- Revenue sources used to calculate each incremental NPV include revenues from electricity export sales contracts and forecast revenues from surplus power exports. Costs were comprised of capital cost estimates; fuel costs, consisting of the water rental rate under *The Water Power Act* and Manitoba Hydro's natural gas price forecast; estimated operating and maintenance costs, including capital maintenance; estimated cost of electricity imports; capital tax; Manitoba's carbon tax on coal; and the forecast of future carbon costs for Manitoba-based generation.
- The discount rate applied to convert the cash flow streams to a net present value. The discount rate was based on Manitoba Hydro's real weighted average cost of capital (WACC). The WACC is calculated using Manitoba Hydro's target debt-to-equity ratio of 75/25, its forecast cost of borrowing of 3.65% plus the 1% debt guarantee fee Manitoba Hydro pays to the Government of Manitoba, and an

²⁴⁶ NFAT Review, PUB/MH1-079(c).

added premium of 3% to set the return for the equity component.²⁴⁷ The initial real discount rate used was 5.05%.²⁴⁸ This was updated for 2013 to 5.40%.²⁴⁹

- Manitoba Hydro used the All Gas Plan with the lowest capital costs as a proxy for the do-nothing option against which the other development plans were compared.
- The various development plans were evaluated relative to the All Gas Plan for their benefits to Manitoba Hydro.
- A “reference case” known as “Ref-Ref-Ref” was used for each alternative development plan. The reference case is based on what Manitoba Hydro considered to be the “most likely” costs and benefits.
- All costs to be incurred prior to June 2014 related to preserving the in-service dates of Keeyask and Conawapa (estimated at \$1.6 billion) were considered to be “sunk costs” and common to all plans and were excluded from the economic analysis.

8.2.2. Manitoba Hydro's Initial Evaluation Results

The results of the economic evaluation for each Plan's Reference Case based on Manitoba Hydro's 2012 planning assumptions are provided below. (Note that the value for the All Gas Plan is zero, as it is the base case.)²⁵⁰

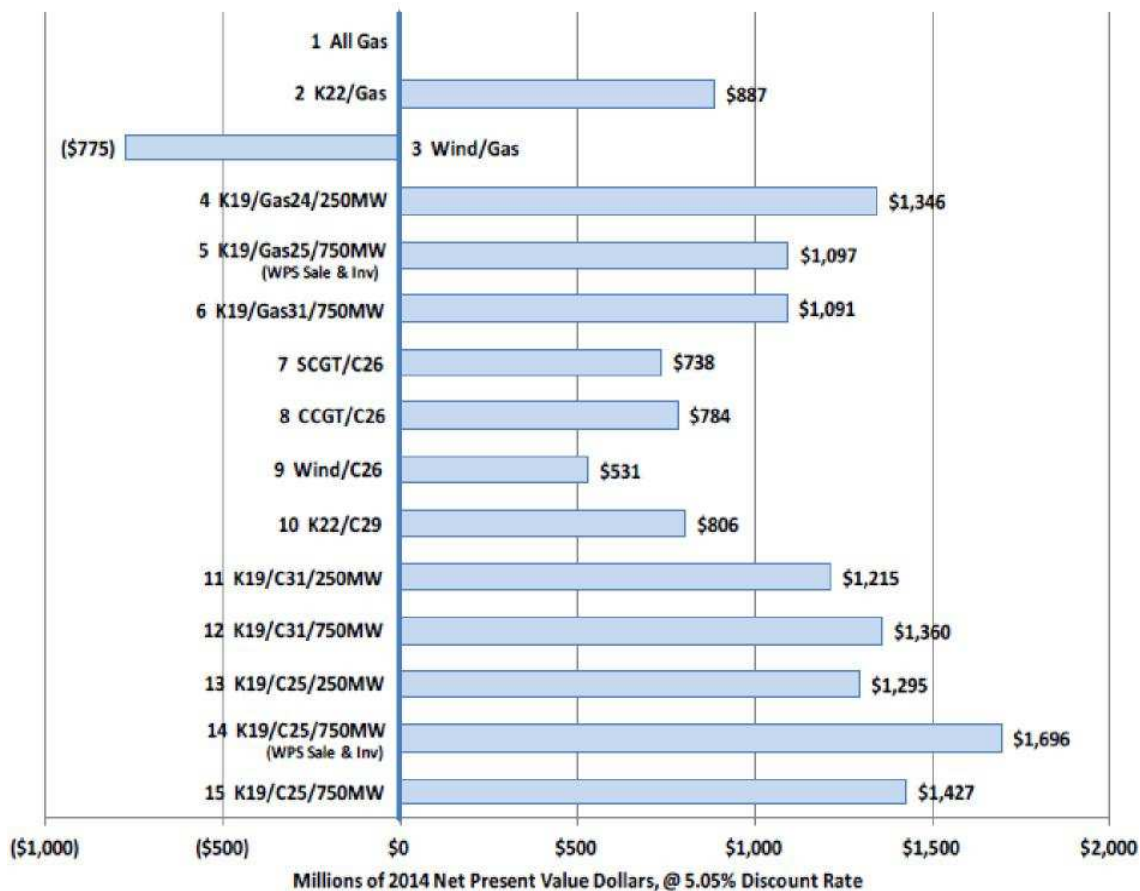
²⁴⁷ NFAT Review, NFAT Application Chapter 9 pp. 6-7.

²⁴⁸ NFAT Review, NFAT Application Appendix 9.3 p. 7.

²⁴⁹ NFAT Review, PUB/MH I-068(c).

²⁵⁰ Manitoba Hydro NFAT Submission, Chapter 9, p. 15.

Figure 11 Results of Manitoba Hydro's Initial Incremental NPV Evaluation
Figure 9.2 DEVELOPMENT PLAN NPVS – BENEFITS TO MANITOBA HYDRO
(RELATIVE TO ALL GAS PLAN)



The initial economic evaluation showed that Plan 14 (Preferred Development Plan) provides significantly better economic benefits (\$1.7billion) compared to Plan 1 (All Gas) and the other development plans. Plans with a 750 MW transmission interconnection and gas generation (rather than Conawapa) following Keeyask (Plans 5 and 6) were virtually identical in overall benefits, but substantially below Plan 14. Manitoba Hydro indicated that given the levels of costs and revenues involved, differences of more than \$100 million would be required to determine conclusively that one Plan was more attractive than another.²⁵¹ The results of the NPV analysis materially changed when Manitoba Hydro updated its plan on March 10, 2014.

²⁵¹ LCA/MH 1-349.

8.2.3. Updated Evaluation During NFAT Review Hearing

On March 10, 2014, Manitoba Hydro provided the Panel with new information that had a material impact on the economics of various development plans:

- the capital cost estimates for Keeyask increased by approximately \$300 million and Conawapa increased by about \$500 million between Capital Expenditure Forecast CEF12 and the March 2014 update;²⁵²
- Wisconsin Public Service (WPS) would not be investing in the 750 MW transmission interconnection, thus changing the costs of Plans that included a WPS investment, including the Preferred Development Plan;
- New Demand Side Management scenarios (DSM Levels 1 – 3), of which initiatives approximating DSM Level 2 will be pursued through the Power Smart program; and
- the possibility of increased domestic load associated with the expansion of the pipeline transportation sector.²⁵³

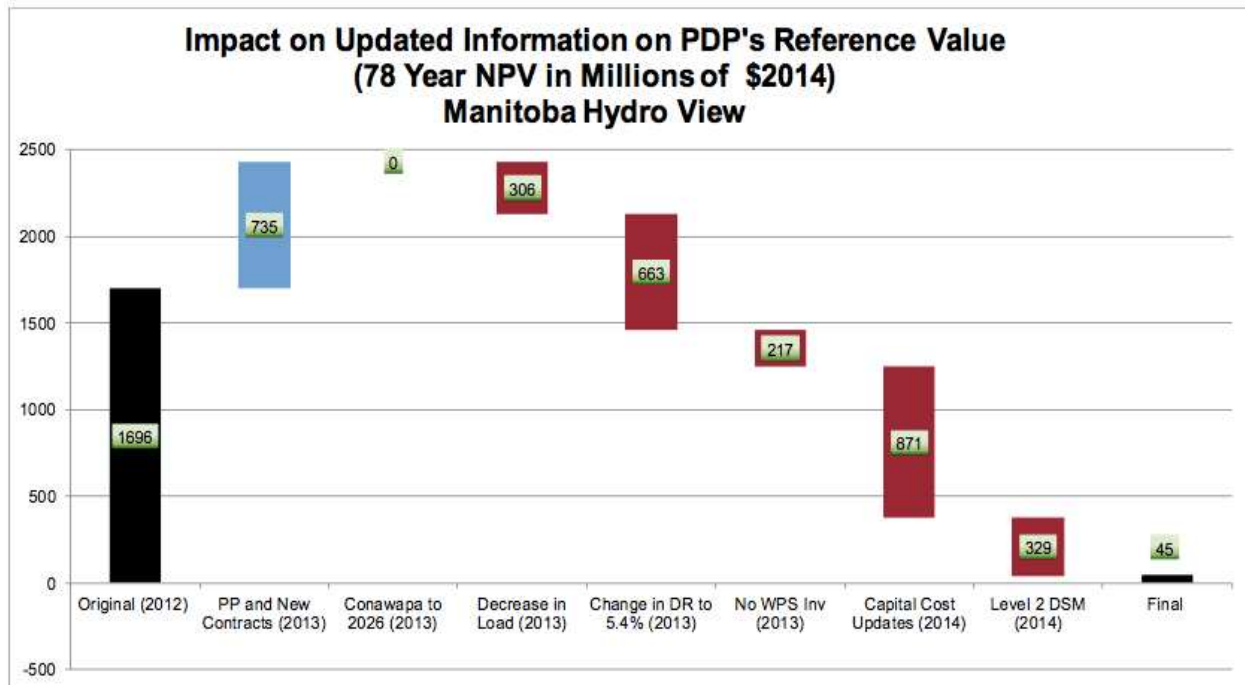
As a result of the updates, the incremental Net Present Value of the Preferred Development Plan was reduced from \$1.7 billion to \$45 million. La Capra depicted the decline in the Net Present Value of the Preferred Development Plan relative to All Gas in the waterfall diagram below.²⁵⁴

²⁵² NFAT Review, Exhibit MH-95, pp. 123-124.

²⁵³ Exhibit MH-95 pp. 103,128.

²⁵⁴ Exhibit LCA-53.

Figure 12 La Capra Associates “Waterfall” Chart Showing Impact of Updated Information on the Economics of the Preferred Development Plan



The largest contributor to the deterioration in the economics of the Preferred Development Plan was the increase in capital costs for Keeyask and Conawapa, which lowered the Net Present Value by \$871 million, while an increase in the discount rate of 35 basis points reduced the Net Present Value by \$663 million. Other factors such as DSM Level 2 and the absence of WPS investment in the 750 MW transmission interconnection also played a material role in reducing the Net Present Value.

Under the updated assumptions, plans that include Keeyask, Gas and the 750 MW transmission line such as Plan 5 provide significantly more economic benefits than the Preferred Development Plan, and Plan 4 (Keeyask19/Gas/250 MW) has the best ranking overall. Manitoba Hydro, however, advised that it no longer considers Plan 4 a viable option because Minnesota Power has applied for regulatory approval to construct to a 750 MW transmission line. These changes are outlined in the Table below.²⁵⁵

At the request of the Panel, Manitoba Hydro analyzed two alternate scenarios under which the Keeyask Project would be deferred to 2026. Both are based on DSM Level 2 and the pipeline load materializing.

²⁵⁵ Exhibit MH-104-15 (Revision 3).

The first Keeyask deferral scenario is based on 2013 planning assumptions and 2014 capital costs. It assumes that Keeyask is deferred to 2026, the Northern States Power 125 MW Sale does not proceed, the coal-fired Brandon Unit 5 is kept operational for drought emergencies until December 2025, the 750 MW U.S. interconnection is built for a 2019/20 in-service date, and the existing Great River Energy 200 MW and NSP 350 MW diversity agreements are extended to 2035. The in-service date for a post-Keeyask gas-fired generation facility does not change. The incremental NPV of such a scenario is \$259 million. This is \$80 million less than the incremental NPV of Plan 5, which has a Keeyask in-service date of 2019.²⁵⁶

Manitoba Hydro's second Keeyask deferral scenario is based on the same set of assumptions as the one above, with the exception that the in-service date of a post-Keeyask gas turbine is deferred based on the extension of the diversity sales. This pushes the assumed in-service date for new gas-fired generation back from 2031 to 2035 and beyond. Manitoba Hydro's analysis indicated that this scenario is marginally more economic than Plan 5, at \$345 million compared to \$339 million for Plan 5. However, this amounts to only a \$6 million difference over 78 years.²⁵⁷ Given the inherent imprecision in this type of analysis, that difference is not material.

Overall, these two deferral scenarios indicate that deferring Keeyask does not improve the economics of a Keeyask-based plan.

Manitoba Hydro also analyzed a scenario in which the Keeyask Project proceeds with a 2019 in-service date, but the 750 MW U.S. transmission interconnection does not get built. This scenario approximates a situation in which Minnesota Power cannot obtain regulatory approval for the Great Northern Transmission Line. The plan, denoted as "Plan 2 Modified" on the Table below, shows that without the interconnection, a Keeyask-based plan has essentially the same 78-year Net Present Value as the All Gas Plan, at an incremental NPV of \$1 million.²⁵⁸

²⁵⁶ May 28, 2014 PUB/MH Pre-Ask

²⁵⁷ May 28, 2014 PUB/MH Pre-Ask

²⁵⁸ May 28, 2014 PUB/MH Pre-Ask

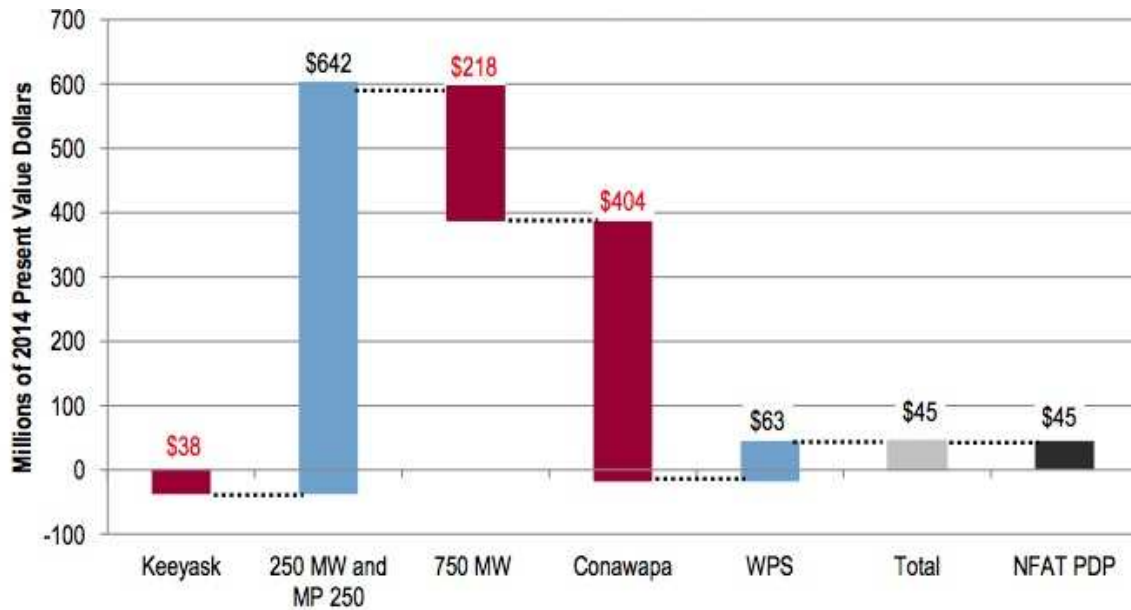
Table 13 Incremental Net Present Values of Alternative Plans Compared to All Gas Plan under Ref-Ref-Ref Assumptions, With In-Service Dates for Subsequent New Generation

	Incremental Net Present Value, (Millions of \$(2014)) Relative to All Gas at Specified Level of DSM			
	Base DSM	DSM Level 1	DSM Level 2	DSM Level 3
Plan 2 (K23/Gas)	164 Gas 2029		-38 K 2031	
Plan 2 Modified (K19/Gas)			1 Gas 40	
Plan 4 – Hypothetical (K19/Gas/250MW)			604 Gas 2040	
Plan 5 (K19/Gas/750MW)	377 Gas 2026	339 Gas 2030	410 Gas 2031	373 Gas 2033
Plan 5 (K19/Gas/750MW) – With Pipeline			339 Gas 2030	361 Gas 2030
Plan 5 Keeyask Deferral Scenario 1 (K26/Gas/750MW19) – With Pipeline			259 Gas 2030	
Plan 5 Keeyask Deferral Scenario 2 (K26/Gas/750MW19) – With Pipeline			345 Gas 2030	
Plan 6 (K19/Gas/750MW)			386 Gas 2040	
Plan 12 (K19/C40/750MW)			-18 Conawapa 2040	
Plan 14 (K19/C/750MW) – With Pipeline	374 Conawapa 2026	124 Conawapa 2030	45 Conawapa 2031	-7 Conawapa 2033

The waterfall diagram below from La Capra's analysis depicts the incremental Net Present Value of each of the components of the Preferred Development Plan. This depiction shows that adding Keeyask would increase the costs by \$38 million relative to the All Gas Plan over the 78-year period based on which NPV is calculated. The value of adding the 250 MW transmission interconnection and the Minnesota Power sale is \$642 million. Moving from a 250 MW to a 750 MW interconnection and adding Conawapa increase the costs by \$218 million and \$404 million, respectively, while the addition of the Wisconsin Public Service sale provides a benefit of \$63 million. As this figure indicates, the Net Present Value reduction associated with Conawapa virtually negates the value of the transmission interconnection. The WPS contract, on the other hand, improves the NPV by \$63 million.²⁵⁹

²⁵⁹ Exhibit LCA-3-3, p. 9S-6, Figure 9-99S.

Figure 13 La Capra Associates Chart Showing the 78-Year Incremental NPV of Preferred Development Plan Components



La Capra stated that alternative metrics, such as Internal Rate of Return and Break-Even Year, do not show the Preferred Development Plan to be the lowest cost development plan.

Another way of looking at the economics of the various plans is to determine the Cumulative Present Value relative to the All Gas Plan (Plan 1) at various points over the 78-year timeframe. Cumulative Present Value provides an understanding of the timing of the costs and benefits over a study period. The Table below shows that Plan 14 (Preferred Development Plan) does not achieve a positive Cumulative Present Value relative to the All Gas Plan until 2089. Plan 5, on the other hand, moves into positive range by 2062, twenty-seven years before the Preferred Development Plan. Plan 4, with the 250 MW line, ranks best overall, but Manitoba Hydro now considers this plan to be hypothetical because of its commercial arrangements with Minnesota Power.

All of the breakeven years for development plans that include Keeyask or Keeyask and Conawapa are beyond the detailed analysis period of 35 years and therefore rely on the extrapolation of assumptions to determine the benefits. Plans with Keeyask and excluding Conawapa break even at 40-50 years compared to All Gas and are therefore less reliant on forecast extrapolation than Conawapa-related plans.²⁶⁰

²⁶⁰ Exhibit, LCA-3-3, p. 9S-8, Figure 9-21S.

Table 14 Summary – CPVs as compared to All Gas Plan at the End of Various Periods, Break-Even Year, 78 year IRR and 78 Year CPV of Total Capital (\$millions in 2014 Present Value Dollars)

Plans	78 Year CPV of					78 Year IRR	Break Even Year (All Gas) Base Case
	Total Capital	78 NPV	50 CPV	35 CPV	20 CPV		
1 All Gas	\$2,764	\$0	\$0	\$0	\$0	N/A	N/A
2 K31/Gas29	\$4,429	(\$38)	(\$349)	(\$798)	(\$1,781)	5.28%	N/A
4 K19/Gas40/250MW	\$5,774	\$604	\$239	(\$284)	(\$1,541)	6.26%	2055
5 K19/Gas31/750MW (WPS)	\$6,215	\$410	\$10	(\$523)	(\$1,899)	5.92%	2062
6 K19/Gas40/750MW	\$6,175	\$386	(\$5)	(\$555)	(\$1,876)	5.90%	2063
12 K19/C40/750MW	\$8,421	(\$18)	(\$954)	(\$2,261)	(\$2,395)	5.36%	N/A
14 K19/C31/750 (WPS)	\$9,528	\$45	(\$863)	(\$2,173)	(\$5,298)	5.42%	2089

The Preferred Development Plan (Plan 14) economics have eroded to essentially break-even with the All Gas Plan, even over the 78-year study period.

Several resource development plans (Plans 4, 5 and 6) that do not include Conawapa have economic benefits over a 78-year Net Present Value basis of about \$400 to \$600 million as compared to the Preferred Development Plan.

The Table above also shows that the net gain on the Net Present Value of the Preferred Development Plan is a miniscule percentage of the incremental investment costs of the plan. For example, the 78-year Net Present Value of the Preferred Development Plan is \$45 million. To carry out the Plan, the incremental investment on a present value basis is over \$9.5 billion. Plans 5 and 6 perform better than the Preferred Development Plan on this metric at just over \$6 billion for \$400 million in benefits. The All Gas Plan represents the lowest investment at \$2.7 billion.

As for the Internal Rate of Return metric, over 78 years the IRR of the Preferred Development Plan is slightly higher than the 5.40% hurdle discount rate; Plans 5 and 6 posted better IRR values, at 5.92% and 5.90% respectively.

8.3.0 La Capra's Alternative Plans

In addition to the various development plans presented in Manitoba Hydro's NFAT Submission, La Capra provided two additional alternative plans – an All Gas plan involving only combined cycle gas turbines (CCGT) rather than mix of CCGT and simple cycle gas turbines (SCGT) relied on by Manitoba Hydro, and a No New Generation Plan relying on increased imports. The economic evaluation of La Capra's CCGT Plan and No New Generation Plan revealed that the CCGT Plan was similar to Manitoba Hydro's All Gas reference case. The No New Generation Plan compared favorably to the All Gas Plan and had better Expected Values than the Preferred Development Plan.

The No New Generation Plan is considered by La Capra to be a hypothetical plan, the results of which point to the potential for added elements such as DSM, import limit capabilities which may have promise either by themselves or in some combination.²⁶¹

Manitoba Hydro suggested that a new transmission line in the U.S. to provide imports to rather than exports from Manitoba is unrealistic.²⁶² Manitoba Hydro saw no value in the hypothetical No New Generation plan, as it is of the view that it has captured the benefits of various elements of the No New Generation Plan through incorporating higher DSM levels, and the 750 MW Manitoba-Minnesota transmission interconnection.²⁶³

8.4.0 Uncertainty Analysis

Manitoba Hydro's economic evaluation also provided an economic uncertainty analysis. This branch of the analysis included a probabilistic analysis, which examined the range of uncertainty around energy prices, the discount rate and capital costs, three factors that Manitoba Hydro asserts have the greatest impact on the economic and financial outcomes of the development plans. Each of those factors is a grouping of several underlying factors. For example energy prices are influenced by export prices, carbon prices and natural gas prices. The discount rate includes the nominal interest rate, inflation and exchange rates. Capital costs include the capital costs of hydro, wind and natural gas generation, transmission costs and certain escalation.

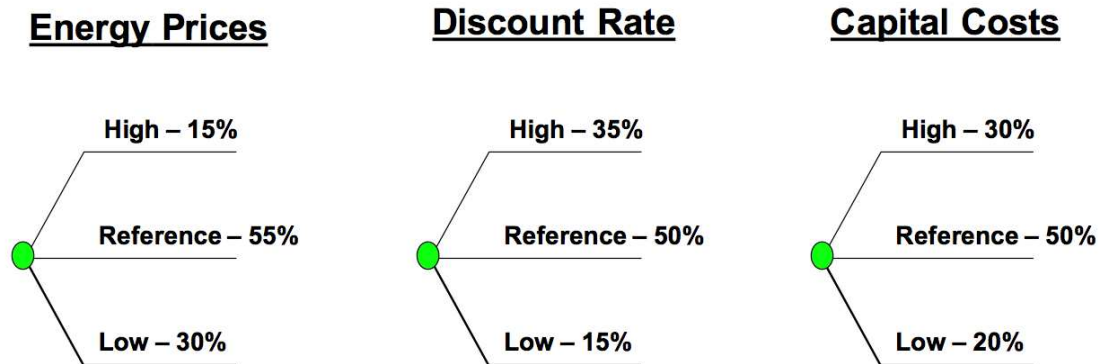
A range consisting of low, reference and high was developed for each of the three factors. Based on its own judgment, Manitoba Hydro determined probability weightings for the high impact factors as follows:²⁶⁴

²⁶¹ Transcript p. 5826.

²⁶² Exhibit MH-204, p. 168.

²⁶³ Exhibit MH-204, p. 169.

²⁶⁴ Manitoba Hydro NFAT Submission, Chapter 10 –p.8, Figure 10.4.

Figure 14 Probability Weightings for Energy Prices, Discount Rate and Capital Cost

The combination of these three groupings and three sets of assumptions in each grouping combined to produce 27 scenarios that were modeled in the initial analysis for 12 of the 15 development plans.

Manitoba Hydro determined both a reference Net Present Value and the Expected Net Present Value which reflected the probability distribution of all outcomes. The use of the Expected Value methodology was recommended by Dr. Borison of Navigant Consulting,²⁶⁵ which assisted Manitoba Hydro in undertaking the uncertainty analysis. Navigant opined that in uncertainty analyses, the single most important output is typically the Expected Value or mean. The Expected Value is the sum of each scenario Net Present Value by the probability of its occurrence. Accordingly, Manitoba Hydro determined the Expected Value of each of the development plans by taking the sum of the Net Present Values multiplied by the appropriate scenario probabilities listed in the column on the far right on the following Table, known as a Probabilistic Analysis Quilt.²⁶⁶

²⁶⁵ Exhibit MH-95 pp. 60-61.

²⁶⁶ Manitoba Hydro NFAT Submission, Chapter 10, Table 10.5, p. 17.

Table 15 Manitoba Hydro's Initial Incremental Economics – All Scenarios

Development Plan			1	3	7	2	4	13	11	6	15	12	5	14	Probabilities
			All Gas	Wind/Gas	SGT/C26	K22/Gas	K19/Gas24 /250Mw	K19/C25 /250MW	K19/C31 /250MW	K19/Gas31 /750MW	K19/C25 /750MW	K19/C31 /750MW	K19/Gas25 /750MW	K19/C25 /750MW	
Energy Prices	Discount Rates	Capital Costs	Millions of 2014 NPV dollars												
Low	Low	H	-4043	-7769	-3309	-3792	-3190	-3459	-3506	-3418	-3642	-3554	-2855	-2941	1.35%
		Ref	-3049	-5403	-2401	-2532	-1877	-2124	-2166	-2130	-2177	-2138	-1616	-1410	2.25%
		L	-2247	-3666	-1655	-1590	-890	-1069	-1099	-1175	-1030	-1022	-703	-292	0.90%
		H	-463	-3056	-1297	-1212	-911	-2510	-2161	-1191	-2816	-2323	-730	-2155	4.50%
		Ref	208	-1478	-582	-278	95	-1368	-1050	-185	-1559	-1153	257	-929	7.50%
		L	750	-323	6	408	837	-473	-176	548	-585	-243	974	20	3.00%
	High	H	1204	-796	-284	25	117	-2029	-1413	-182	-2383	-1622	203	-1810	3.15%
		Ref	1708	384	323	785	963	-994	-434	679	-1243	-592	1060	-698	5.25%
		L	2114	1245	822	1336	1580	-189	327	1297	-364	201	1674	157	2.10%
		H	-5014	-7167	-1760	-2511	-1796	206	-334	-2041	498	0	-2103	853	2.48%
		Ref	-4020	-4902	-852	-1251	-482	1541	1006	-753	1963	1415	-865	2284	4.13%
		L	-3217	-3064	-107	-309	504	2597	2073	202	3110	2531	49	3402	1.65%
Ref	Low	H	-671	-2354	23	-46	341	152	104	85	170	190	109	470	8.25%
		Ref	0	-775	738	887	1346	1295	1215	1091	1427	1360	1097	1696	13.75%
		L	542	380	1326	1573	2089	2189	2089	1824	2401	2270	1813	2645	5.50%
		H	1308	-82	879	1091	1258	109	391	998	2	366	1041	268	5.78%
		Ref	1812	1098	1487	1851	2104	1144	1370	1859	1143	1396	1898	1380	9.63%
		L	2218	1959	1986	2402	2721	1949	2132	2478	2022	2189	2512	2235	3.85%
	High	H	-6435	-6719	-355	-1499	-692	3819	2796	-1006	4455	3410	-1694	4372	0.68%
		Ref	-5441	-4353	552	-239	621	5154	4135	282	5921	4826	-456	5803	1.13%
		L	-4638	-2616	1298	703	1607	6210	5203	1237	7068	5941	458	6922	0.45%
		H	-1158	-1767	1241	941	1398	2746	2308	1127	2993	2571	713	2940	2.25%
		Ref	-487	-189	1956	1874	2403	3888	3420	2134	4250	3741	1703	4166	3.75%
		L	55	966	2543	2560	3146	4783	4293	2867	5225	4652	2417	5115	1.50%
High	Low	H	1210	533	1956	2017	2246	2170	2127	1993	2236	2228	1691	2203	1.58%
		Ref	1713	1712	2563	2777	3092	3206	3106	2854	3377	3259	2549	3315	2.63%
		L	2120	2573	3063	3328	3709	4010	3867	3473	4256	4051	3163	4170	1.05%
	High	H	-6435	-6719	-355	-1499	-692	3819	2796	-1006	4455	3410	-1694	4372	0.68%
		Ref	-5441	-4353	552	-239	621	5154	4135	282	5921	4826	-456	5803	1.13%
		L	-4638	-2616	1298	703	1607	6210	5203	1237	7068	5941	458	6922	0.45%



The above Probabilistic Analysis Quilt is based on the incremental difference of the Net Present Value against the least capital cost option, which is the All Gas Plan (Plan 1). Green cells indicate an incremental positive Net Present Value relative to the Net Present Value of the All Gas Plan, while red cells indicate a negative incremental Net Present Value.

Manitoba Hydro determined a single un-weighted scenario (representing the reference value for the three risk factors) with the resulting incremental Net Present Value of \$1.7 billion for Plan 14 (Preferred Development Plan) as compared to the All Gas Plan. Based on the Expected Value economics, the relative Expected Value NPV was \$1.085 billion based on the original NFAT Submission.²⁶⁷

Table 16 Manitoba Hydro Initial Expected Value Calculation

Development Plan	1	3	7	2	4	13	11	6	15	12	5	14
	All Gas	Wind/Gas	SGT/C26	K22/Gas	K19/Gas24 /250Mw	K19/C25 /250MW	K19/C31 /250MW	K19/Gas31 /750MW	K19/C25 /750MW	K19/C31 /750MW	K19/Gas25 /750MW	K19/C25 /750MW
Millions of 2014 NPV dollars												
10th Percentile - "Risk"	-3502	-4599	-1217	-1249	-898	-1988	-1362	-1181	-2186	-1594	-828	-1429
25th Percentile	-560	-2200	-297	-248	115	-650	-363	-183	-904	-361	139	-204
75th Percentile	1481	383	1363	1636	2092	1854	2074	1832	2008	2009	1726	2255
90th Percentile - "Reward"	1905	1209	1955	2007	2479	3180	2953	2215	3360	3220	2256	3377
Expected Value	-70	-1084	455	564	971	712	736	706	760	821	772	1085
Ref-Ref-Ref NPV	0	-775	738	887	1346	1295	1215	1091	1427	1360	1097	1696

²⁶⁷ Manitoba Hydro NFAT Submission, Chapter 10, Table 10.6, p. 17.

This analysis showed that the incremental Expected Value for the Preferred Development Plan was higher than the Expected Value for all other development plans.

On March 10, 2014, Manitoba Hydro updated the capital cost estimates for Keeyask and Conawapa, and adjusted for Wisconsin Public Service's decision not to invest in the 750 MW U.S. Great Northern Transmission Line. Manitoba Hydro also updated for 2013 planning assumptions, which included enhanced levels of DSM and potential new pipeline load. With that information, Manitoba Hydro also updated the probability weightings as follows:²⁶⁸

Figure 15 March 10, 2014 Updated Probability Weightings for Energy Prices, Discount Rate, and Capital Costs



Based on this updated information, the incremental Net Present Value on a reference case basis for the Preferred Development Plan declined to \$45 million relative to All Gas Plan from the \$1.7 billion in the original business case. On the basis of reference case comparisons, the Preferred Development Plan was no longer the most economic plan, where other alternatives such as Plan 5, which excludes Conawapa, had materially higher economic value on an incremental NPV basis.

On March 27, 2014, Manitoba Hydro provided an incomplete update of Expected Values of eight plans based on the updated capital cost assumptions, as well as the removal of the originally anticipated investment of Wisconsin Public Service in the Great Northern Transmission Line. This update was still based on 2012 planning assumptions, without enhanced DSM and without the anticipated new pipeline load. In this update, Manitoba Hydro also lowered the probability weightings for 'high' capital costs from 30% to 20% based on Manitoba Hydro's view that there would be increased cost certainty from the recently received Keeyask general civil contract.

²⁶⁸ Exhibit MH-104-8.

The update was provided for 7 of the 12 plans originally analyzed, as well as for Plan 8, as reflected in the following Table.²⁶⁹

Table 17 March 10, 2014 Updated Expected Values

Development Plan	1	2	4	8	6	12	5	14
	All Gas	K22/Gas	K19/Gas24 /250MW	CCGT/C26	K19/Gas31 /750MW	K19/C31 /750MW	K19/Gas25 /750MW	K19/C25 /750MW
							WPS Sale & no WPS Inv	
	Millions of 2014 NPV Dollars							
10th Percentile -"Risk"	-953	-862	-727	-1457	-1007	-2512	-909	-2946
25th Percentile	-244	-622	-290	-980	-556	-1482	-367	-1760
75th Percentile	483	1026	1339	916	1099	1232	824	1105
90th Percentile - "Reward"	738	1448	2019	1898	1749	3239	1475	3653
Expected Value	-9	268	651	143	386	115	268	120
Ref-Ref-Ref NPV	0	489	917	403	662	536	484	614

Most significantly, the update reduced the Expected Value for the incremental Net Present Value of the Preferred Development Plan to \$120 million. This is over \$900 million less than the \$1.085 billion Expected Value forecast in the original business case. Furthermore, the revised analysis indicates that those plans that exclude Conawapa have higher Expected Values than those that include it. The updated analysis reveals that Plan 4 has the highest Expected Value (Manitoba Hydro now considers Plan 4 to be hypothetical). Excluding Plan 4, Plan 6 (K19/Gas32/750 MW) has the highest Expected Value (\$386 million) followed by Plan 5 at \$268 million. Plan 14 has the most downside risk.²⁷⁰

²⁶⁹ Exhibit MH-104-8.

²⁷⁰ Exhibit MH-104-8.

Table 18 March 10, 2014 Updated Probabilistic Quilt

Development Plan			1	2	4	8	6	12	5	14
			All Gas	K22/Gas	K19/Gas24 /250MW	CCGT/C26	K19/Gas31 /750MW	K19/C31 /750MW	K19/Gas25 /750MW	K19/C25 /750MW
			WPS Sale & no WPS Inv							
Energy Prices	Discount Rates	Capital Costs	Millions of 2014 NPV Dollars							
Low	Low	H	-1062	-1401	-851	-1501	-1079	-2143	-758	-1825
		Ref	-68	16	646	106	392	-53	698	424
		L	734	1205	1898	1449	1613	1750	1906	2359
	Ref	H	-463	-1751	-1512	-2398	-1793	-3717	-1546	-3969
		Ref	208	-677	-334	-1085	-614	-1977	-355	-2010
		L	750	232	658	15	369	-476	637	-325
	High	H	-88	-1782	-1761	-2625	-2060	-4202	-1872	-4838
		Ref	416	-891	-748	-1480	-1033	-2668	-820	-3044
		L	823	-133	110	-519	-172	-1345	61	-1500
Ref	Low	H	-2033	-120	543	325	298	1410	-7	1869
		Ref	-1039	1296	2040	1932	1770	3501	1449	4118
		L	-237	2486	3292	3275	2991	5304	2658	6053
	Ref	H	-671	-585	-260	-910	-517	-1204	-707	-1345
		Ref	0	489	917	403	662	536	484	614
		L	542	1397	1910	1503	1645	2037	1477	2300
	High	H	17	-716	-620	-1343	-880	-2214	-1034	-2759
		Ref	520	175	393	-198	148	-680	18	-966
		L	927	933	1251	762	1008	643	899	578
High	Low	H	-3454	892	1647	2005	1333	4820	402	5388
		Ref	-2460	2309	3143	3612	2804	6911	1858	7638
		L	-1658	3498	4396	4955	4025	8714	3066	9573
	Ref	H	-1158	402	797	469	526	1178	-103	1125
		Ref	-487	1476	1974	1782	1704	2918	1088	3084
		L	55	2384	2967	2882	2687	4418	2081	4770
	High	H	-82	210	368	-156	115	-352	-384	-824
		Ref	422	1101	1381	989	1143	1182	669	969
		L	828	1859	2239	1949	2003	2505	1549	2513

The uncertainty analysis also reveals that the upside potential for Plans that include Conawapa comes with scenarios that include high export prices, low capital costs and/or low interest rates. These scenarios are uncertain at best.

The above quilt reflects a reference Net Present Value for the Preferred Development Plan of \$614 million. This led to an Expected Value of \$120 million. The above quilt does not fully reflect the updated economic information, which indicates that the Preferred Development Plan has a Reference Net Present Value of \$45 million. Accordingly, it is possible that the Expected Value remains overstated at \$120 million. Manitoba Hydro did not provide any further updates to the Expected Value analysis, nor a probability quilt on the Preferred Development Plan or alternatives based on 2013 planning assumptions with enhanced DSM and potential Pipeline load due to timing restrictions to run the full analysis.

Many witnesses described the Expected Value as a key risk output and more informative than the Ref-Ref-Ref value. The Panel was not in a position to comment on how the Preferred Development Plan would have performed relative to other plans based on the risk-adjusted basis.

La Capra also performed an uncertainty analysis, but instead of referencing every Net Present Value to the All Gas Plan Ref-Ref-Ref scenario, it provides a comparative analysis across plans using consistent assumptions of uncertain parameters based on the same probabilities used by Manitoba Hydro. For example, the Preferred Development Plan's Hi-Low-Ref scenario was compared to the All Gas Hi-Low-Ref scenario. What La Capra determined was that when interim period economic analysis results are used to develop metrics for 20, 35, and 50 year study periods, the Preferred Development Plan does not appear to be the lowest-cost resource plan alternative even when a probabilistic scenario analysis covering 27 scenarios is included. Plans with Keeyask but without Conawapa have more favorable economic uncertainty profiles than the Preferred Development Plan.²⁷¹

La Capra also conducted a sensitivity analysis of changing the discount rates, capital costs and export prices and their impact on the Preferred Development Plan. La Capra concluded the following:²⁷²

- A modest increase in discount rates or the elimination from consideration of the low discount rate scenarios postulated by Manitoba Hydro would make the Preferred Development Plan have the same present values of costs over 78 years as the All Gas Plan on an Expected Value basis.
- Several Plans have lower costs than the Preferred Development Plan, even over 78 years, when higher discount rates are assumed.
- Modest increases in capital cost assumptions for the Keeyask and Conawapa projects would also result in other development plans having lower costs than the Preferred Development Plan, even over 78 years.
- A slightly lower view of export market prices substantially erodes Manitoba Hydro's expected economic benefits of the Preferred Development Plan.

CAC's expert, Dr. Wayne Simpson, plotted the risk against expected return to determine that Plan 4 was the superior plan, followed by Plan 6, Plan 5, and then Plan 2. Dr. Simpson was of the view that Manitoba Hydro's evaluation was not robust to changing costs and other updates.²⁷³ Another CAC expert, Mr. Harper, also provided a probabilistic analysis and determined that the Preferred Development Plan was not preferred from an economic perspective.²⁷⁴

²⁷¹ Exhibit LCA-12 p. 80.

²⁷² Exhibit LCA-12. p.129.

²⁷³ Exhibit CAC-69, pp. 14-15.

²⁷⁴ Exhibit CAC-68 pp. 47-48.

La Capra's view was supported following the updates to the Keeyask and Conawapa capital costs that showed plans with Keeyask and the interconnection as being superior to plans containing both Keeyask and Conawapa.

The Panel received comments from several witnesses about the limitations of Manitoba Hydro's updated analysis, particularly the fact that it was not updated to reflect new DSM levels. Many felt that their analysis was hampered by the absence of revised Expected Values that would factor in the new levels of DSM. The rapidly changing economic analysis constituted a significant problem to both the Panel and Interveners in analyzing the Preferred Development Plan and alternatives.

8.5.0 Specific Risk factors

Manitoba Hydro also evaluated the sensitivity of selected development plans to factors such as drought, long-term climate change, Manitoba load growth and Demand Side Management. These risk factors are discussed in Chapter 10.

8.6.0 Selected Issues Relating to Manitoba Hydro's Analytical Approach

8.6.1. Treatment of Cash Transfers to the Province

Manitoba Hydro's economic analysis (not its MA-BCA analysis) includes payments to government as a benefit, which is discounted at the same rate as benefits to Manitoba Hydro. CAC's expert witness, Mr. Harper, raised two concerns with this approach. First, the inclusion of cash transfers to the Government clouds the perspective of the economic analysis in that it no longer represents only Manitoba Hydro's perspective. Second, this inclusion does not adequately portray the broader societal perspective because the discount rate applied is the same discount rate used to determine the NPVs from Manitoba Hydro's perspective.

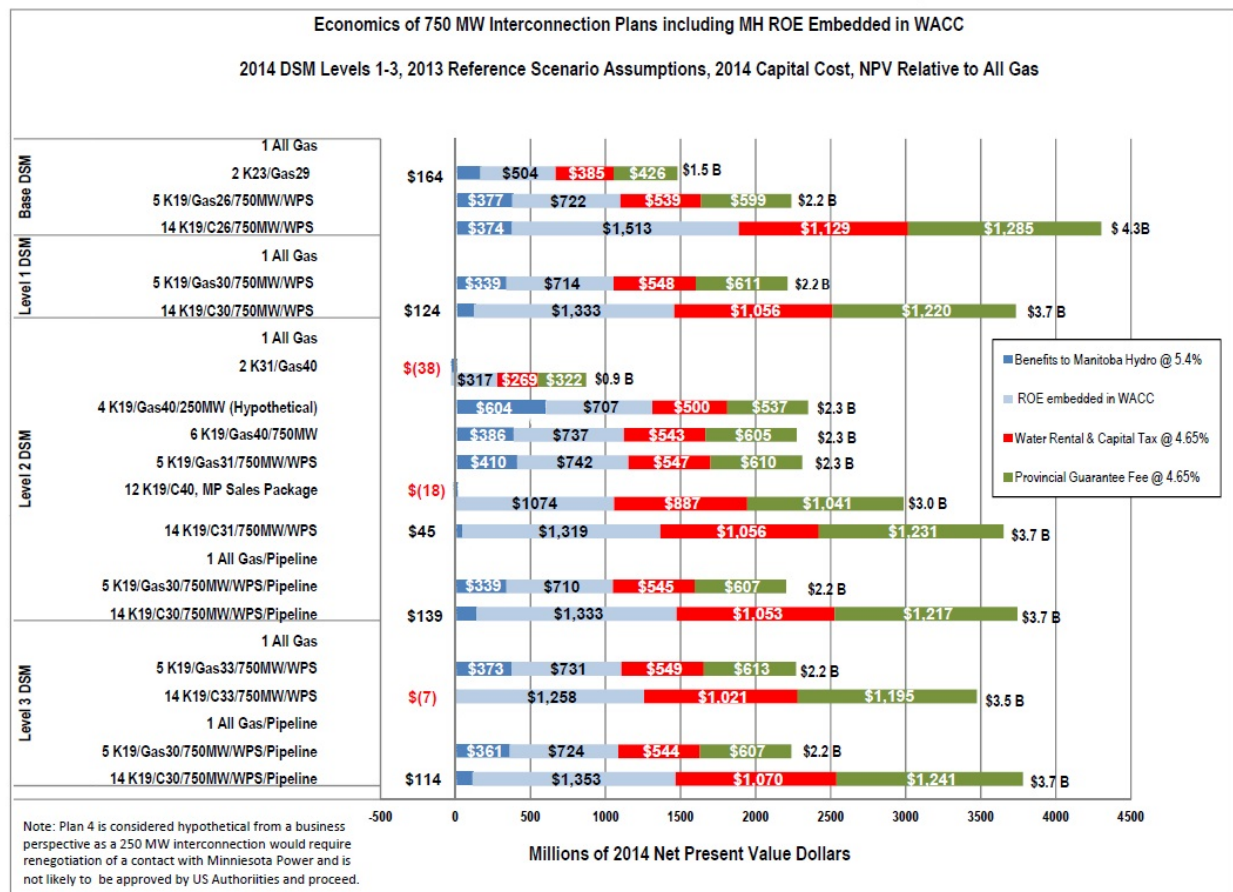
Mr. Harper pointed out that in the MA-BCA analysis (see Chapter 11), Manitoba Hydro used a 6% discount rate for government benefits, which is intended to reflect the social opportunity cost of capital from the taxpayers' point of view. Furthermore, Mr. Harper is of the view that the MA-BCA analysis properly recognizes that the debt guarantee fee payable by Manitoba Hydro to the Province of Manitoba is a cost associated with compensating the province for the increased risk the province assumes for guaranteeing Manitoba Hydro's debt.²⁷⁵

²⁷⁵ Exhibit CAC-30, pp. 25-26.

8.6.2. Embedded Return on Equity

In concert with its March 10, 2014 update, Manitoba Hydro introduced into its economic evaluation the concept of the Return on Equity embedded in its Weighted Average Cost of Capital (WACC). Based on this change in methodology, Manitoba Hydro continues to include transfers to the Government, including the debt guarantee fee, in its updated Net Present Value analysis, but now uses a lower discount rate of 4.65%, rather than the 5.40% WACC used to calculate the benefits to Manitoba Hydro. The net effect of this was to nullify the application of a WACC to the analysis of provincial benefits and return to an analysis based on Manitoba Hydro's cost of borrowing plus the 1.0% debt guarantee fee. The impact of lowering the discount rate in this manner was to increase the indicated level of benefits to be derived by the Province. The diagram below depicts this approach.²⁷⁶

Figure 16 Manitoba Hydro Embedded Return on Equity



²⁷⁶ Exhibit MH-171 (Revision 4).

Based on this new approach, the total NPV of provincial benefits calculated by Manitoba Hydro is \$3.7 billion for the Preferred Development Plan for DSM Level 2 including the derived \$1.3 billion in embedded equity. The analysis was provided for illustrative purposes and was not suggested to replace the WACC being used for corporate economic purposes²⁷⁷.

Morrison Park questioned the significance of the calculation, noting that it was not directly relevant to ratepayers or the government, but simply represented Manitoba Hydro's view.²⁷⁸ MIPUG's expert witness indicated that it could be informative, but should not be the primary consideration.²⁷⁹

In its final argument, MIPUG noted that one of the main concerns with the embedded return on equity methodology is that it is calculating the Net Present Value by looking only at the need to finance the underlying debt. MIPUG stated:

*Conceptually, we know that larger plans require other levels of returns – whether that is for First Nation benefit sharing, setting aside reserves, or helping build to a debt:equity target. All of those other considerations cannot be achieved with a plan that is solely (barely) able to repay its debt over its life, which is what a 4.65% discount rate effectively represents.*²⁸⁰

CAC's witness, Mr. Harper, questioned whether embedded equity could be viewed as a benefit. The Preferred Development Plan involves more capital and that requires additional equity in order to sustain Manitoba Hydro's financial integrity.²⁸¹

The following Table shows the comparable economics excluding the embedded return on equity:²⁸²

²⁷⁷ Exhibit MH-95 p. 131.

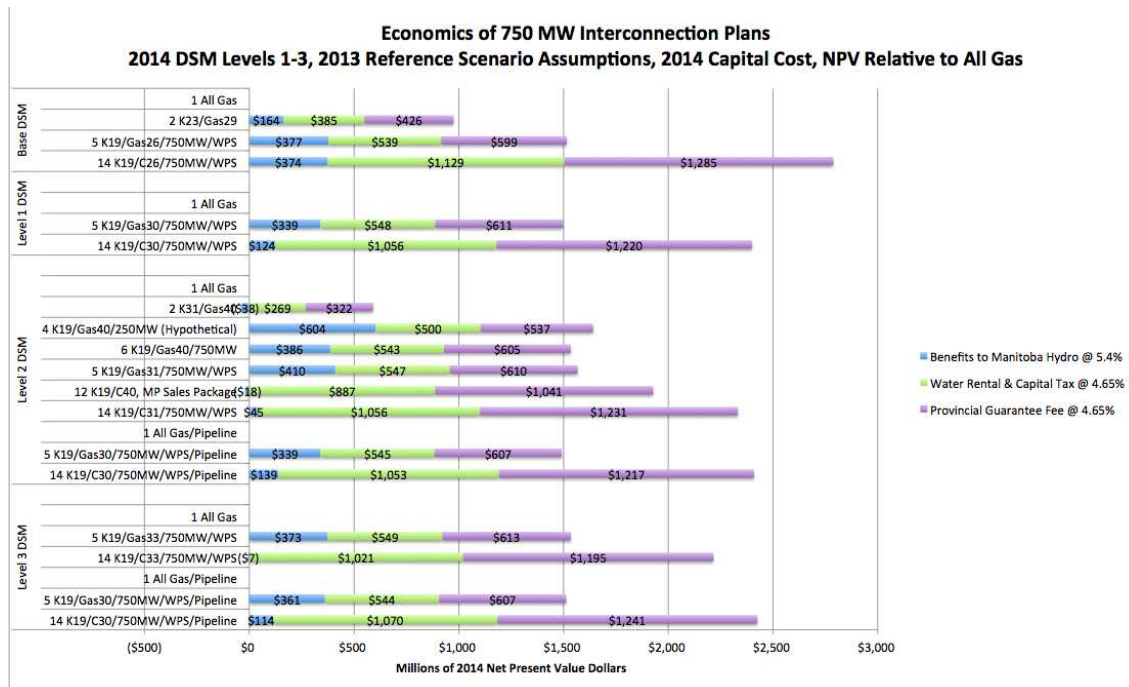
²⁷⁸ Transcript, p. 7406.

²⁷⁹ Transcript, p. 10129.

²⁸⁰ Exhibit MIPUG-28, p. 30.

²⁸¹ Transcript, p. 8542.

²⁸² Derived from Exhibit MH-171, excluding embedded equity.

Figure 17 Manitoba Hydro Exhibit #171 Excluding Embedded Equity

8.6.3. How Determinative is the NPV Analysis?

Manitoba Hydro maintains that Net Present Value is the best metric for economic analysis when comparing mutually exclusive plans, while Internal Rate of Return (IRR) is useful when analyzing incremental cash flows.²⁸³ Dr. Borison, Manitoba Hydro's expert, indicated that the Net Present Value metric is the primary decision making tool used to evaluate such major capital investments.²⁸⁴

La Capra stressed that the Net Present Value metric, while important, did not reveal everything that one might need to know about the economic benefits of a plan. Manitoba Hydro's singular focus on the 78-year Net Present Value metric as the basis for comparing alternative development plans is too limited in scope for a decision of this magnitude. Manitoba Hydro does not offer any comparative metrics that capture important differences in the plans through the study period that bear on the timing of costs and benefits and the associated risks.²⁸⁵ For example, the Internal Rate of Return demonstrates how large an investment is needed to obtain the benefit shown. Similarly, Cumulative Present Value provides a snapshot of the economics at a particular time

²⁸³ Transcript, p. 1686, p.1878.

²⁸⁴ Transcript, p. 1686.

²⁸⁵ Exhibit LCA-12 p. 9A-151.

and will provide important information on the time required for proposed investments to provide benefits and on assessing implications of forecast risk.²⁸⁶

Morrison Park stated that for a typical investor, the discount rate could either represent the investor's hurdle rate, or the total cost of capital for the project if calculating Internal Rate of Return rather than total return. However, Morrison Park noted that neither of these uses appears to be appropriate in the current case. Since minimizing cost to ratepayers is a priority, use of the discount rate seems better focused on the comparison of ratepayer costs over time.²⁸⁷

8.6.4. Timeframe of the Analysis

As mentioned earlier in this chapter, Manitoba Hydro used a 78-year time period in its economic evaluation, comprised of a 35-year detailed evaluation and an extension of the 35-year period by 43 years to the end of the service life of the longest-lived asset, a hydro-electric generating station. The values for the 43-year period are an extrapolation of those used in the detailed analysis representing a residual value of a long-lived project. Some witnesses were of the view that the study period was too long and exposed the economic evaluation to too much uncertainty. Manitoba Hydro maintains that for the purpose of an economic analysis, it is appropriate for the timeframe to extend to the end of the life of the longest-lived asset.

The MMF's expert witness, Whitfield Russell Associates, indicated that the 78-year period exceeds Manitoba Hydro's 20-year financial forecast and its 35-year Power Resource Plan period. It was noted that there could be many changes over that period which could affect how revenues and costs were treated.²⁸⁸

Both Morrison Park and La Capra cautioned that there was much uncertainty and unpredictability associated with a long timeframe used in Manitoba Hydro's analysis.

Morrison Park indicated that there is a significant danger in assuming that a view of the future from the perspective of today will be very accurate. For example, technological advances could render the underlying assumptions obsolete even in relatively short periods of time.²⁸⁹ The technology development of hydraulic fracturing in the natural gas industry over the past decade is only a recent example of expectations about future market conditions being totally undermined: widespread expectations a decade ago

²⁸⁶ Exhibit LCA -3, p. LCA-9.

²⁸⁷ PUB/MPA 32(a)

²⁸⁸ Exhibit MMF-31, pp. 5-6; Transcript, p. 10591.

²⁸⁹ Exhibit MPA-3, p. 16.

were that North America would by now be supply-constrained and increasingly reliant on expensive imports of natural gas.

La Capra expressed concern that a 78-year study period is unusual in evaluating utility investments and indicated there are risks inherent in forecasting over such a long period of time, and the estimates of benefits over that period of time are subject to much uncertainty.²⁹⁰

La Capra further states that it is common for decision makers to place much less weight on long-term forecasts of long-term benefits in conjunction with plans with high front-end costs. This means it is valuable to consider intertemporal issues, payback, Internal Rate of Return and other metrics that better articulate the temporal relationship between investments and the associated benefits expected from those investments.²⁹¹

By contrast MIPUG considered the 78-year evaluation appropriate for purposes of considering which plans should be pursued, but stated that to analyze ratepayer impacts, time horizons from the very short-term to the full forecast period is required.²⁹²

8.6.5. Treatment of Sunk Costs

The treatment of the \$1.6 billion in sunk costs was also raised as an issue. In the Net Present Value analysis, the expenditures to preserve the in-service dates of Keeyask (\$1.2 billion) and Conawapa (\$400 million) were treated as common costs to all plans, rather than as costs applied to the Preferred Development Plan or to plans that include Keeyask or Conawapa. Some witnesses maintained that this treatment biases the analysis in favour of the Preferred Development Plan.

Whitfield Russell identified the treatment of costs associated with Bipole III as a particular concern. This witness was of the view that the costs of Bipole III were not sunk costs because the facility is yet to be built. Whitfield Russell further suggested that including Bipole III's costs as a common cost biases the economic analysis in favour of the hydro-based plans. In this witness's opinion, Bipole III should not be treated as a neutral factor in assessing all of the development plans because not all of the plans require its construction. Consequently, Bipole III's costs should be considered as a cost attributable to the hydro-based plans rather than to the system as a whole.²⁹³

²⁹⁰ Exhibit LCA-12, p. 9A-24.

²⁹¹ Exhibit LCA-12, p. 9A-24.

²⁹² Exhibit MIPUG-28, p. 28.

²⁹³ Exhibit MMF-31, pp. 23-24.

8.6.6. Discount Rate

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

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

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

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

8.7.0 Conclusions of the Panel

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

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

²⁹⁴ Exhibit CAC-30 pp. 20-21.

²⁹⁵ Exhibit CAC-69, p. 26.

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

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

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

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

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

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

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

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

9.0.0 The Rate Impacts of the Preferred and Alternative Development Plans

9.1.0 Introduction

Proceeding with any of the development plans that Manitoba Hydro considered to meet electricity demand will have an impact on the rates that customers pay for electricity, as well as an impact on Manitoba Hydro's overall financial position. All plans require Manitoba Hydro to make significant expenditures, although the nature and timing of the expenditures vary. Some plans, particularly those that include hydroelectric generating stations, require large up-front capital expenditures and involve comparatively low operating expenses, while others, such as those that rely on gas-fired generators as the principal generating option, have relatively lower up-front capital costs and higher operating and maintenance costs over time. Customer rates will increase materially under all plans.

Rate increases above the rate of inflation will also be required over the coming decade even if Manitoba Hydro were not to proceed with developing new generation resources. Manitoba Hydro informed the Panel that the need to refurbish aging infrastructure and pay for Bipole III would be significant drivers of these increases.

As Manitoba Hydro is obliged to recover its costs from its domestic customers, ratepayers are ultimately responsible for paying for the Preferred Development Plan or any other power resource option that may be pursued. The Terms of Reference address the issue of rates by requiring the Panel to consider the impact on domestic electricity rates over time with and without the Plan and with alternatives.

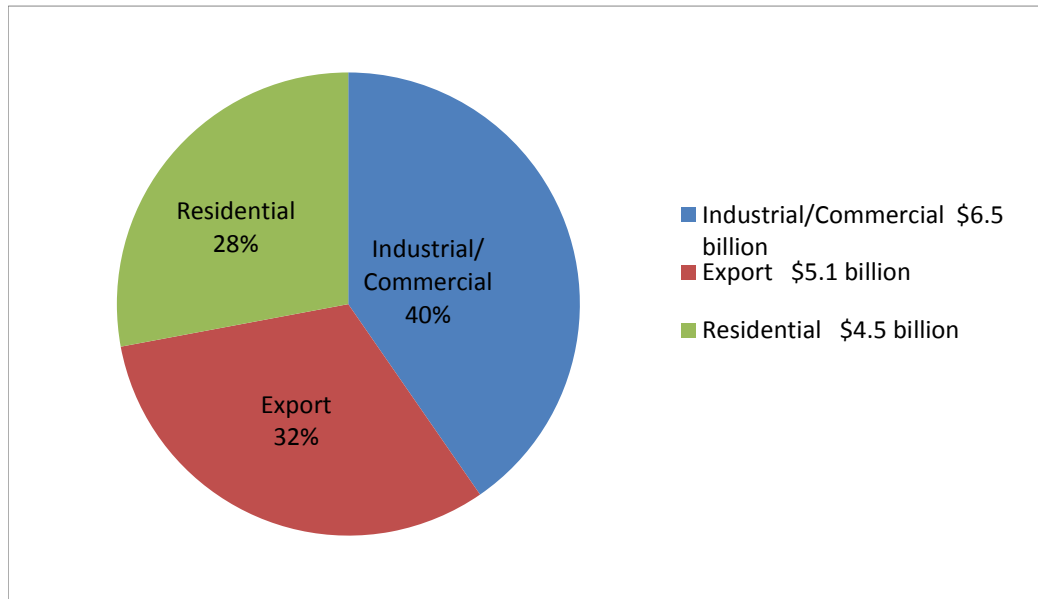
9.2.0 Manitoba Hydro's Current Revenue Base

Manitoba Hydro's revenue base from electric operations is derived from domestic rates and export revenues. Domestic electricity revenues accounted for just over two-thirds of Manitoba Hydro's revenue in the past 10 years. This share has been increasing as domestic consumption and rates have risen and export revenues and volumes have declined, largely due to lower opportunity export prices and the drop in U.S. consumption associated with a continued downturn in economic activity in Manitoba Hydro's U.S. export markets.

Manitoba Hydro is regulated on a cost of service basis and recovers its costs from domestic customers through PUB-approved rates. Ratepayers are divided into different customer classes; for example, residential, and general service, small, medium and

large. Each class has a different rate structure. The Figure below depicts Manitoba Hydro's electricity revenues by customer type over the period 2003/04 – 2012/13.²⁹⁶

Figure 18 Electricity Revenue Sources, 2003/04 to 2012/13



Over the past decade, Manitoba Hydro has generally exported between 10,000 to 12,000 GWh of energy annually, which approximates 40% to 50% of the energy sold to domestic customers during the period.²⁹⁷ Exports have contributed about 32% of Manitoba Hydro's revenue²⁹⁸ and aided in keeping Manitoba Hydro's domestic electricity rates among the lowest in Canada and North America. Export revenues have declined in recent years from 2009 levels of over \$600 million to about \$350 million to \$400 million annually because of the weakening in wholesale market prices resulting from the recession and lower natural gas prices.

Generally, export revenues come from two different sources: opportunity export sales and longer-term sales under export contracts. Opportunity sales are classified as on-peak and off-peak and may be priced above or at market prices at the time of the sale. Sales under export contracts are at the price agreed to in the contract, which is typically higher than the opportunity price. The types of export products Manitoba Hydro sells and the expected revenues are discussed in Chapter 6. For the purpose of the financial analysis, Manitoba Hydro assumes that all surplus dependable energy (dependable

²⁹⁶ Exhibit MH-111, p. 8.

²⁹⁷ Exhibit LCA-9, p. 6-2.

²⁹⁸ Over the past 10-years, export revenues totaling some \$5.6 billion have accounted for nearly one-third of Manitoba Hydro's revenues for electricity sales. See https://www.hydro.mb.ca/corporate/electricity_exports.shtml, accessed May 17, 2014.

energy that is not currently subject to long-term contracts) can be sold at long-term firm prices.²⁹⁹

9.3.0 Manitoba Hydro's Financial Targets

Manitoba Hydro has three self-imposed key financial targets:

1. A minimum debt-to-equity ratio of 75/25;
2. An interest coverage ratio of greater than 1.20; and
3. A capital coverage ratio of greater than 1.20.

These targets are important because they provide a way to measure Manitoba Hydro's overall financial strength and guide proposed rate increases. The targets are imposed by Manitoba Hydro's Board of Directors and are monitored by credit rating agencies.

Manitoba Hydro's plan to construct new generating facilities and make capital expenditures to renew the existing infrastructure, as well as the costs involved with reliability improvements such as Bipole III, will put pressure on meeting these financial ratios over the next decade.

9.3.1. Debt-to-Equity Ratio

The debt-to-equity ratio indicates the portion of Manitoba Hydro's assets that are financed through long-term and short-term debt, and through funds from operations from customer rates and export revenues. This ratio is a measure of the overall financial risk to Manitoba Hydro. Attaining a debt-to-equity ratio of 75/25 means that 25% of Manitoba Hydro's assets would be financed through internally generated funds (domestic rates and export revenues) rather than through debt.

The debt-to-equity ratio is a long-term target, which serves as a financial guideline only, not an annual requirement. In 2013 it stood at 75/25.³⁰⁰ Manitoba Hydro expects a significant deterioration in this ratio over the next 20 years to about 90/10 in the 2020s as debt levels increase because of Bipole III and the Preferred Development Plan. The Figure below depicts Manitoba Hydro's forecasted debt-to-equity ratio to 2033 (assuming development of the Preferred Development Plan) as compared between Integrated Financial Forecast IFF13 and with Integrated Financial Forecast IFF12.³⁰¹

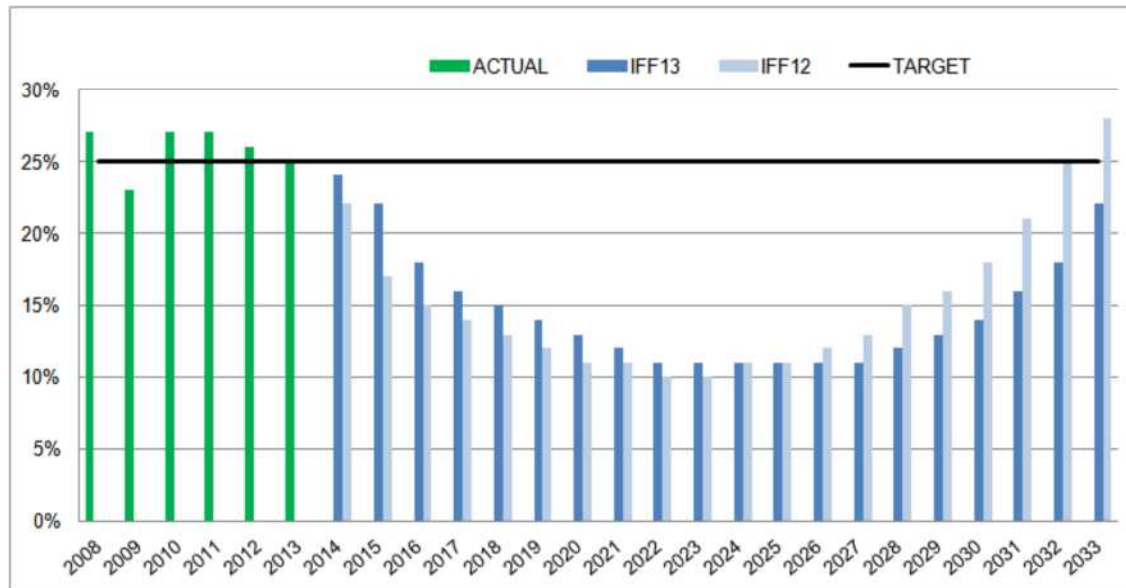
²⁹⁹ 5x16 peak sales are sales that take place five days per week (Monday to Friday) when market load is typically higher. Off-peak periods are hours during the week when load is normally lower; for example overnight and over certain hours on the weekends.

³⁰⁰ Exhibit MPA-3, p. 18.

³⁰¹ Exhibit MH-111, p. 6.

The 2014 updated Keeyask and Conawapa capital costs are not reflected in the debt-to-equity ratios shown in the following Figure.

Figure 19 Manitoba Hydro's Debt-to-Equity Ratio, 2008 to 2033



9.3.2. Interest Coverage Ratio

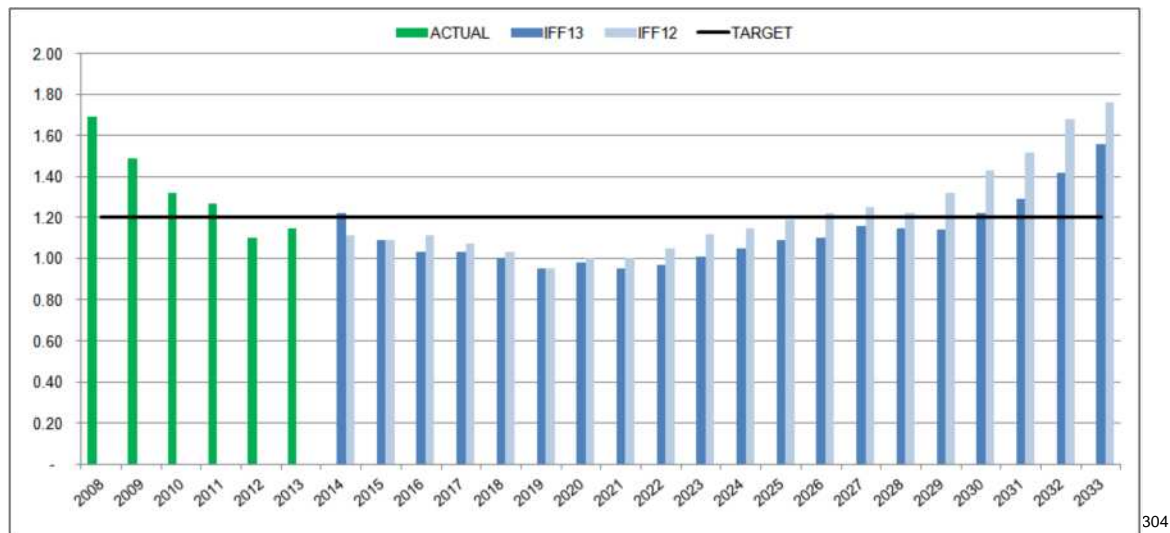
The Interest Coverage Ratio signals Manitoba Hydro's ability to meet its interest payment obligations from its net income. Manitoba Hydro seeks to maintain an interest coverage ratio of greater than 1.20, which gives it a 20% cushion of annual cash available over expected interest costs. An interest coverage ratio below 1.0 indicates that Manitoba Hydro may need to borrow to meet its interest obligations. Manitoba Hydro has indicated that it can maintain its interest payment obligations if the interest coverage ratio is greater than 0.8.³⁰²

In 2013, the interest coverage ratio stood at 1.15. Manitoba Hydro is projecting the Interest Coverage Ratio to fall below the target level for a period of 15 years because of higher debt levels and related borrowings associated with Bipole III and the Preferred Development Plan.

The Figure below depicts Manitoba Hydro's Interest Coverage Ratio forecast to 2033 (assuming the development of the Preferred Development Plan) as compared between 2013 and 2012 Integrated Financial Forecasts.³⁰³

³⁰² Transcript p. 2915.

³⁰³ Exhibit MH-111, p.17.

Figure 20 Interest Coverage Ratio, 2008 to 2033

304

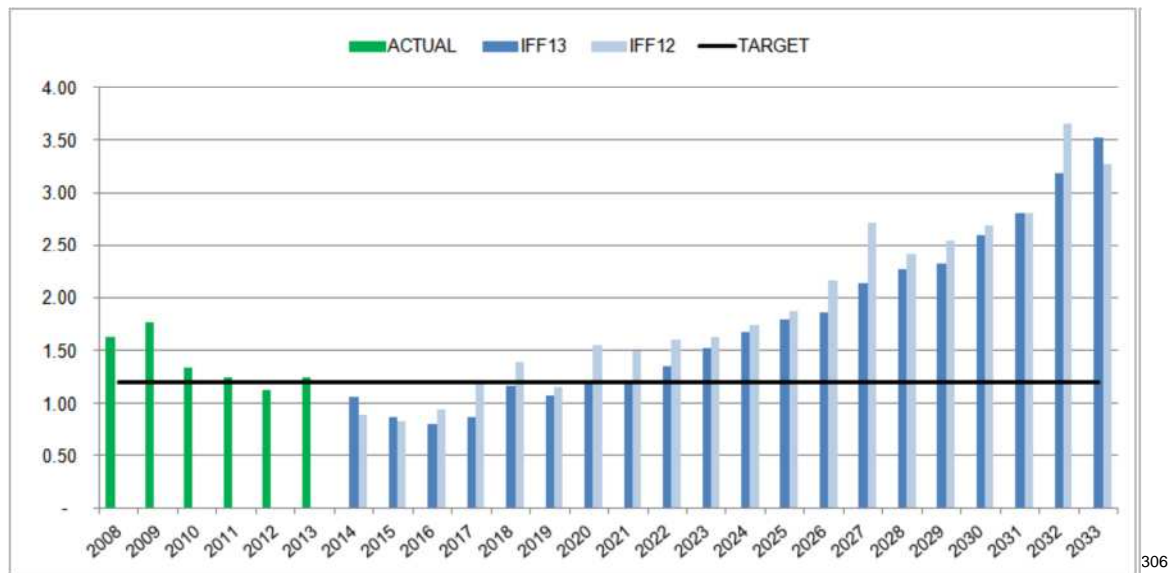
9.3.3. Capital Coverage Ratio

The Capital Coverage Ratio measures Manitoba Hydro's ability to fund sustaining base capital expenditures, excluding major new generation projects and transmission facilities, out of current cash flow from operations. Base capital expenditures are capital investment required to renew Manitoba Hydro's existing assets. Manitoba Hydro's target Capital Coverage Ratio is greater than 1.20. A capital coverage ratio of less than 1.0 indicates that Manitoba Hydro must borrow to fund its annual base capital requirements.

Manitoba Hydro expects its Capital Coverage Ratio to dip below the 1.20 target from 2014 to 2021, and even below 1.0 for much of that period. The Figure below depicts Manitoba Hydro's 2013 forecast for the Capital Coverage Ratio (assuming the development of the Preferred Development Plan) to 2033 as compared to its 2012 forecast.³⁰⁵

³⁰⁴ Exhibit MH-11, p. 17.

³⁰⁵ Exhibit MH-111, p.18.

Figure 21 Capital Coverage Ratio, 2008 to 2033

306

9.4.0 Manitoba Hydro's NFAT Financial Evaluation

Manitoba Hydro provided a financial evaluation of eight of the 15 different development plans it had considered in the economic evaluation. The financial evaluation compared the impact of each development plan on electricity rates and Manitoba Hydro's financial position.

The financial evaluation featured the same uncertainty analysis framework that was applied to the economic analysis, namely three values (reference, high, and low) for three variables (energy prices, economic indicators, and capital costs). A distinct difference was that \$1.4 billion in sunk costs that were excluded from the economic analysis were included in the financial analysis for alternatives that did not include either or both Keeyask or Conawapa, as they represent real costs that will have to be recovered through rates.

The following eight plans were the subject of the financial analysis based on 2012 planning assumptions:³⁰⁷

³⁰⁶ Exhibit MH-111, p. 18.

³⁰⁷ Manitoba Hydro NFAT Submission, Chapter 11, p. 3.

Table 19 **Evaluated Plans: Financial Analysis Based on 2012 Planning Assumptions**

Interconnection	Plan #	Development Plan
No New Interconnection	1	All Gas
	2	K22/Gas
	7	Gas/C26
250 MW Interconnection	4	K19/Gas/250 MW
	13	K19/C25/250 MW
	12	K19/C31/750 MW
750 MW Interconnection	6	K19/Gas/750 MW
	14	K19/C25/750 MW (Preferred Development Plan)

Of the eight plans evaluated, the Plan 1 (All Gas) and Plan 14 (Preferred Development Plan) presented the most significant contrasts in overall resource strategy, as they have two different resource components (gas vs. electric) and two distinct orientations (domestic need vs. export). Manitoba Hydro did not provide a financial analysis of a Wind/Gas scenario, as it was screened out due to its economic performance against other plans.

Manitoba Hydro prepares a 20-year financial forecast annually. The NFAT financial analysis was based on a 50-year forecast of electric operations to 2062. Manitoba Hydro selected a 50-year study period “in order to be consistent with the long-term nature of hydro-electricity assets and to provide a sufficient time frame to analyze the benefits and costs of each development plan.”³⁰⁸ The financial analysis used a 35-year time period (coinciding with the period for which Manitoba Hydro's SPLASH³⁰⁹ computer model simulates system operations) with additional extrapolation to extend the analysis to 50 years. All the financial analysis was performed in nominal dollars, which contrasts with the economic evaluation results that were provided in real dollars, excluding the impact of general inflation.

During the NFAT Review hearings, Manitoba Hydro filed an updated financial analysis for Plan 1 (All Gas) and Plan 14 (Preferred Development Plan), as well as a new financial analysis for Plan 5 (K19/Gas/750 MW).³¹⁰ Following this initial tranche of evaluations, financial evaluations were provided for Plans 2, 4, 6 and 12, and then for Plans 1, 5, and 14 with DSM Level 2 and the pipeline load.³¹¹

³⁰⁸ Manitoba Hydro NFAT Submission, Chapter 11. p. 3.

³⁰⁹ SPLASH is the acronym for Manitoba Hydro's computer model, Simulation Program for Long-term Analysis of System Hydraulics.

³¹⁰ Exhibits MH-104-12-1 to 104-12-4.

³¹¹ Exhibits MH-104-12-5 to 104-12-7.

The plans were updated as follows:

- Plan 1 (All Gas), Plan 5 (K19/Gas/750 MW) and Plan 14 (Preferred Development Plan, K/19/C26-33/750 MW) were updated for Base and DSM Levels 1 – 3, 2014 updated reference Keeyask and Conawapa capital costs, and the 2013 Electric Load Forecast and discount rate, as well as for DSM Level 2 and the pipeline load.
- Plans 5 and 14 were updated for the various DSM levels, the 2013 Electric Load Forecast and discount rate, and the 2014 updated high capital cost scenario for Keeyask and Conawapa.
- Plan 2, (K31/Gas), Plan 4 (K19/Gas/ 250 MW), Plan 6 (K19/Gas/750 MW) and Plan 12 (K19/C40/750 MW) were updated for DSM Level 2, 2014 updated reference capital costs for Keeyask and Conawapa, and the 2013 Electric Load Forecast and discount rate.³¹²

The updates were made to the IFF12 forecast model used for the NFAT Submission evaluation, as the IFF13 forecast was not extended to 50 years. Consequently, the base capital expenditures are based on IFF12 assumptions.³¹³

Manitoba Hydro conducted its financial evaluation of the development plans on the basis of applying even annual rate increases over an 18-year period to achieve a debt-to-equity ratio of 75/25 by 2031/32. For years beyond 2031/32, Manitoba Hydro set annual rates to maintain a 1.20 interest coverage ratio to the end of the 50-year study period.

The financial modeling provides comparative metrics in order to assess the proposed development plans rather than a definite rate path. Manitoba Hydro told the Panel that it has a longstanding strategy of smoothing rates over a period of time in developing its rate proposals. This essentially involves pre-funding of major generation and transmission projects. Accordingly, actual rate increases may be higher or lower than projected. The Public Utilities Board must approve Manitoba Hydro's electricity rates. Proposed rate increases will depend on Manitoba Hydro's future revenue requirements and will be the subject matter of General Rate Applications before the Public Utilities Board.

³¹² Exhibit MH-104-12-5.

³¹³ Exhibit MH-204, p. 188.

9.5.0 Impact of Development Plans on Electricity Rates

Manitoba Hydro's initial evaluation showed that the Preferred Development Plan would result in equal annual rate increases of 3.95% through 2031/32. Other development Plans ranged from 3.43% for Plan 1 (All Gas) to 3.86% for Plan 7 (Gas/Conawapa 26). The magnitude of rate increases under all options was significantly higher than the forecast level of inflation. Over a 78-year time frame, the Preferred Development Plan had the lowest overall cumulative nominal annual rate increases compared to other plans at 106% versus 176% for Plan 1 and 134% for Plan 7.³¹⁴

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

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

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

³¹⁴ PUB/MH I-0149a, Revised, p. 7.

³¹⁵ Exhibit MH-104-12-6, p. 1.

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

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

9.6.0 Impact of Demand Side Management Programs on Rates

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

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

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

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

9.7.0 Impact of Sunk Costs on the Projected Rate Increases

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

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

³¹⁶ Exhibit MH-180, p. 31.

³¹⁷ Transcript, p. 2883. See also, Exhibit MH -111, p. 38.

³¹⁸ Manitoba Hydro NFAT Submission, Chapter 11, p. 5.

³¹⁹ MIPUG/MH I-003c.

The Panel was told that one of the reasons there is less of a distinction in the rate implications of the various plans than one might otherwise expect is that the sunk costs of the Keeyask and Conawapa projects will be applied to plans that do not include those assets because of the need to recover those costs.

Morrison Park noted before the Panel that sunk costs represent money spent that will have to be accounted for in some way.

*"However, the reality is if you don't go forward with the Keeyask project, you still have to pay the \$1.4 billion. So that \$1.4 billion loss, if you will, in certain circumstances has to be addressed and taken into account. So is that in some sense unfair to other options? Well, I suppose. If an alternative option only costs \$4 1/2 billion and Keeyask all-in costs 5 1/2, once you add the sunk costs of Keeyask onto the other option, suddenly it doesn't look so attractive. Fair or not, that's reality. ... And that's how you have to address the attractiveness of the different options, because it's what ratepayers have to pay."*³²⁰

La Capra Associates provided the Panel with an analysis of the impact of sunk costs on various development plans. The Table below, based on 2012 assumptions, illustrates these impacts. It is clear from this analysis that Plan 1 (All Gas) bears the brunt of sunk costs, followed by Plan 7 (Gas/C26). Plans that include Keeyask but not Conawapa are less affected by sunk costs because the expenditures associated with Conawapa (\$400 million to date) are less than the money spent to date on Keeyask (\$1.2 billion).³²¹

Table 21 Rate Increases by Development Plan under Reference Conditions With and Without Sunk Costs

Plan #	Plan Short Name	Even-Annual Rate Increases (2012/13 to 2031/32)		Cumulative Nominal Rate Increases at 2031/32	
		With Sunk Costs	Without Sunk Costs	With Sunk Costs	Without Sunk Costs
1	All Gas	3.43%	3.05%	90%	78%
7	Gas/C26	3.86%	3.58%	105%	95%
2	K22/Gas	3.49%	3.40%	92%	89%
4	K19/Gas/250	3.42%	3.33%	90%	87%
6	K19/Gas/750	3.50%	3.41%	92%	89%

Evidence was provided that the sunk costs may not have to be recovered through rates in the early years if either Keeyask or Conawapa remain in Manitoba Hydro's planning

³²⁰ Transcript, p. 7283.

³²¹ Exhibit LCA-13, p.10A-31.

horizon.³²² Furthermore, the Panel was told that even if the sunk costs are written off, a one-time charge could be taken or the amount of costs found to not have a future value could be written off over different time frames. Any rate proposal related to a write-off of sunk costs would have to be approved by the PUB.

9.8.0 Impact of Bipole III on Rates

The Panel also heard evidence about the rate implications of the Bipole III transmission project, currently projected to cost \$3.3 billion dollars. The last capital cost update for Bipole III was in 2010. In addition to Bipole III, the Riel Converter Station is required to deliver the power from Bipole III. When the project is completed and in service by 2017/18, Manitoba Hydro has determined approximately \$280 million will have to be recovered annually through rates.³²³ This would require a one-time rate increase of about 20%.

9.9.0 Export Revenue Forecasts

Manitoba Hydro indicated to the Panel that export revenues would continue to be an important source of revenue to help offset the costs of the Preferred Development Plan. To this end, Manitoba Hydro has negotiated a number of contracts with other parties as part of the development of the Preferred Development Plan, the most notable being the contracts with Minnesota Power (MP) and Wisconsin Public Service (WPS). These contracts, which all expire by 2036, take up a portion of the dependable output of Manitoba Hydro's system, leaving some room for Manitoba Hydro to negotiate more firm dependable contracts and sell a substantial amount of other surplus power in the opportunity export market. The terms of all of Manitoba Hydro's export contracts are relatively short (10 to 15 years) compared to the expected 100-year life of the proposed new generating stations. Consequently, Manitoba Hydro will be looking to renew contracts with existing counterparties or find new contract purchasers to sustain its export revenue stream.

The indicative rate increases associated with the various development plans are based on projections of operating results to meet a 75/25 debt-to-equity ratio by 2031/32. A key factor influencing the operating results is how much revenue Manitoba Hydro will be able to realize from export sales as opposed to domestic rates.

The level of export revenue is affected by the assumptions underlying export sales, including the volume of future exports and future export prices. Export prices, in turn are

³²² Transcript, pp. 2883-2884.

³²³ Exhibit MH-211.

affected by the prices of natural gas and other fuels used to generate power in the export markets, mainly the U.S. MISO market. The implementation of a carbon tax premium is a crucial factor in Manitoba Hydro meeting its forecast export revenue assumptions. Manitoba Hydro's export sales assumptions and revenues are discussed more fully in Chapter 6 of this Report.

The following Table shows Manitoba Hydro's projected revenues from domestic and extra-provincial sources for selected years from 2015 to 2033.³²⁴

Table 22 Projected Domestic and Extra-Province Revenues, DSM Level 2 + Pipeline Load \$ million

Plan 14 (Preferred Development Plan)	2015	2019	2022	2026	2029	2033
Domestic Customers	1,456	1,798	2,124	2,624	3,075	3,610
Gross Export Revenue	383	460	871	835	858	1,351
Plan 5 (K19/Gas/750 MW)	2015	2019	2022	2026	2029	2033
Domestic Revenue		1,762	2,052	2,485	2,869	3,319
Gross Export Revenue		460	871	836	873	906

By 2033, Manitoba Hydro is projecting that domestic revenue will more than double and export revenues will more than triple from current levels. These domestic revenue assumptions are based on even annual rate increases of 4.38% until 2032. The DSM Level 2 scenario assumes Conawapa coming into service in 2031. If Plan 5 (No Conawapa) were implemented, even annual rate increases to 2032 would be 3.86%, or over 0.53% (53 basis points) lower.

To the extent that export revenues fall short of Manitoba Hydro's forecasts, additional rate increases will be required to cover Manitoba Hydro's costs. Conversely, if export revenues exceed forecasted levels, ratepayers will benefit.

Morrison Park provided an updated analysis of the role of exports in the 2013 versions of the plans, as noted in the Table below.³²⁵

³²⁴ Exhibit MH-104-12-7, p. 25, 31.

³²⁵ Exhibit MPA 3-1, p. 22.

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

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

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

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

9.10.0 Other Metrics for Examining Rates and Revenues

9.10.1. Net Present Value Analysis

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

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

³²⁶ Exhibit MPA 3-1, p. 22.

³²⁷ Transcript, p. 7392.

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

9.10.2. Impact of Rate Increases on Ratepayers

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

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

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

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

9.10.3. Present Value of Customers' Revenues

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

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

³²⁸ Exhibit LCA-13, p. 10A-60.

³²⁹ Transcript, pp. 246-248.

³³⁰ Transcript, p. 3031.

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

With respect to the present value of ratepayer costs, the model demonstrated the sensitivity of the various plans to changes in the discount rate. The All Gas Plan and the Preferred Development Plan represent different rate patterns, with the All Gas Plan showing rate increases for the "first generation" of ratepayers that are less prolonged and not as high as those projected for the Preferred Development Plan. For the "second generation" of ratepayers the pattern reverses. According to Morrison Park, this is where the discount rate and the time value of money become apparent: if ratepayers would prefer to save now and pay later, they would have a high discount rate such as 10% or more and choose Plan 1 (All Gas). Conversely, if they were to focus on long-term benefits, they would have a low discount rate of 6% or less and choose the Plan 14 (Preferred Development Plan). Plans 4 and 6 fall in between Plan 1 and Plan 14.³³¹

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

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

Morrison Park provided the total cost to ratepayers based on each 2013-updated plan, assuming annual rate increases of 3.8%. The Net Present Value total cost to ratepayers by plan is as follows³³²:

³³¹ Exhibit MPA-3, p. 46.

³³² Exhibit MPA 3-1, p.11.

Table 24 Morrison Park's Calculation of Total Cost to Ratepayers at 3.8% Maximum Annual Rate Changes

Present Value and Nominal Value of Domestic Revenue Reference Economics, Energy and Capital Reference 2013 Manitoba Load; DSM Level II (2015 - 2062) (\$ in millions)						
	All Gas	Plan 2	Plan 4	Plan 5	Plan 6	PDP
Present Value						
NPV @ 6.00%						
Average	\$39,659	\$40,284	\$39,440	\$39,636	\$39,696	\$41,999
Maximum	\$40,915	\$41,569	\$40,561	\$40,671	\$40,816	\$43,854
Minimum	\$38,596	\$39,282	\$38,274	\$38,571	\$38,642	\$40,815
Standard Deviation	\$486	\$485	\$494	\$465	\$492	\$708
Present Value						
NPV @ 10.00%						
Average	\$21,999	\$22,248	\$22,225	\$22,312	\$22,345	\$23,322
Maximum	\$22,406	\$22,720	\$22,561	\$22,666	\$22,736	\$23,886
Minimum	\$21,583	\$21,787	\$21,737	\$21,864	\$21,895	\$22,961
Standard Deviation	\$201	\$257	\$183	\$168	\$172	\$225
Nominal Value						
Average	\$161,316	\$162,570	\$151,161	\$151,791	\$151,794	\$158,555
Maximum	\$172,403	\$176,999	\$161,403	\$164,331	\$162,887	\$172,101
Minimum	\$153,275	\$154,896	\$141,117	\$142,701	\$142,824	\$149,689
Standard Deviation	\$4,568	\$4,059	\$4,278	\$4,212	\$4,449	\$4,950

Morrison Park made the following observations from the above analysis:³³³

- The results for Plans 4, 5, and 6 (all of which include Keeyask and exclude Conawapa) are within 1% of each other across all cases (based on 6%, 10% discount rates and nominal dollars and also across maximum, minimum, and average values).
- Plan 2, which includes Keeyask but no transmission interconnection, and is therefore a domestically focused Plan, is slightly inferior to Plans 4, 5, and 6 at a discount rate of both 6% and 10%. In nominal dollar terms, however, it is significantly inferior, which indicates that its costs to ratepayers are higher farther out in the future.
- The All Gas Plan is competitive with Plans 4, 5, and 6 at a discount rate of 6%, but slightly superior (by approximately 1%) when the discount rate is 10%. But in nominal dollar terms, the All Gas Plan has the highest ratepayer cost of all Plans modeled, which indicates that its costs to ratepayers are significantly higher farther out in the future.

³³³ Exhibit MPA 3-1, pp.11-12.

- The Preferred Development Plan is approximately 5% inferior to Plans 4, 5, and 6 across all cases. It is the worst performing plan in terms of Net Present Value calculated at both 6% and 10%, but is superior to the All Gas Plan and Plan 2 in nominal dollar terms.
- The Preferred Development Plan also has the highest standard deviation, which suggests that it is the most sensitive to hydrology. Notably, there is no discount rate at which the Preferred Development Plan is superior to Plans 4, 5, and 6: they are superior to the Preferred Development Plan regardless of discount rate assumptions (note that nominal dollars are equivalent to a discount rate of 0%).

Morrison Park also provided a comparison between 2013 and 2014 ratepayer costs based on the updated 2013 information on a reference case basis. Morrison Park noted a significant change in the original 2013 analysis resulting in noteworthy changes in the costs to ratepayers.³³⁴

Table 25 Morrison Park's Calculation of Ratepayer Cost Impacts of 2014 Update of Planning Assumptions

Present Value of Domestic Revenue Reference Economics, Energy and Capital 2013 Plans vs. 2014 Plans (2015 - 2062) (\$ in millions)						
	All Gas	Plan 2	Plan 4	Plan 5	Plan 6	PDP
Present Value						
NPV @ 6.00%						
2013 Average	\$43,791		\$42,878		\$43,301	\$44,230
2014 Average	\$39,659	\$40,284	\$39,440	\$39,636	\$39,696	\$41,999
Difference	-\$4,132		-\$3,438		-\$3,605	-\$2,231
%	-9.4%		-8.0%		-8.3%	-5.0%
NPV @ 10.00%						
2013 Average	\$23,623		\$23,476		\$23,633	\$24,148
2014 Average	\$21,999	\$22,248	\$22,225	\$22,312	\$22,345	\$23,322
Difference	-\$1,624		-\$1,251		-\$1,288	-\$826
%	-6.9%		-5.3%		-5.4%	-3.4%

Morrison Park noted that across all Plans, projected total costs for Manitoba ratepayers have declined. It was notable that the decline occurred despite the fact that expected interest rates have increased, capital costs for projects have increased, and inflation rates have increased slightly. According to Morrison Park, the declines in the total ratepayer costs "*speak to the powerful impact of dramatically expanded DSM programs (4x the spending contemplated in the 2013 Business Case), which are expected to*

³³⁴ Exhibit MPA 3-1, p.14.

*dramatically reduce Manitoba domestic load, and free up more capacity for export.*³³⁵

Furthermore, the plans now contemplate a reduced level of capital spending on generation projects (and generally later in time), although spending on enhanced DSM programs will begin almost immediately.

As for the specific plans, the gap between All Gas and the Keeyask-based plans has lessened. The All Gas Plan is now marginally superior to Plans 4, 5 and 6 at a 10% discount rate, and essentially identical at a 6% discount rate. Based on the 2013 Plans, Plans 4 and 6 were superior to All Gas at 6%, and Plan 4 was also superior at 10%. When it comes to the Preferred Development Plan, however, that gap between that Plan and the other Plans increased.³³⁶

9.10.4. Plan 5 (K19/Gas/750 MW) Rate Pathway vs. Plan 14 (Preferred Development Plan)

Morrison Park mapped the rate increases based on 99 hydrological conditions and determined that based on an annual 3.8% or 4.0% maximum allowable rate increase scenario, Plan 5 (K19/Gas/750 MW) rate requirements are radically different from Plan 14 (Preferred Development Plan). Rate increases under Plan 5 peak in early 2030s then fall for approximately 10 years while under the Preferred Development Plan the rate increases do not peak until between 2038 and 2040.³³⁷

9.10.5. Intergenerational Impacts

Morrison Park's analysis also considered the intergenerational impacts of the projected rate increases. Morrison Park noted that irrespective of the plan chosen, ratepayers would face the maximum allowable rate increases for the next 15 years under all plans. After approximately 2030, however, the plans separate fairly dramatically and continue to do so for many decades. Morrison Park calculated ratepayer impacts at different timeframes, as shown in the Figure below.³³⁸

³³⁵ Exhibit MPA 3-1, p.14.

³³⁶ Exhibit MPA 3-1, p.14.

³³⁷ Exhibit MPA 3-1, pp.16-17.

³³⁸ Exhibit MPA 3-1, p. 23.

Table 26 Morrison Park's Calculation of Ratepayer Costs for Alternative Periods

Present Value of Domestic Revenue Reference Economics, Energy and Capital 20 year, 30 year and 48 year periods (\$ in millions)						
Present Value	All Gas	Plan 2	Plan 4	Plan 5	Plan 6	PDP
NPV @ 6.00%						
2015 - 34	\$24,244	\$24,094	\$24,911	\$24,965	\$24,993	\$25,212
2015 - 44	\$31,014	\$31,728	\$32,111	\$32,314	\$32,407	\$34,694
2015 - 62	\$39,659	\$40,284	\$39,440	\$39,636	\$39,696	\$41,999
NPV @ 10.00%						
2015 - 34	\$17,224	\$17,133	\$17,572	\$17,599	\$17,612	\$17,721
2015 - 44	\$19,900	\$20,149	\$20,440	\$20,526	\$20,566	\$21,488
2015 - 62	\$21,999	\$22,248	\$22,225	\$22,312	\$22,345	\$23,322

Morrison Park's analysis indicates that in the first 20-year period, Plan 2 (Keeyask/Gas) is the least costly for ratepayers, likely because it does not require Keeyask's sunk costs to be written off (as the All Gas Plan does), while new spending on Keeyask occurs relatively late in the period. When the examined period is 48 years, Plans 4 (K19/Gas/250 MW), 5 (K19/Gas/750MW, with WPS sale), and 6 (K19/Gas/750MW) have caught up to or surpassed the All Gas Plan, which suggests that ratepayers in that final 18-year period are dramatically better off under Keeyask-based plans.³³⁹

The Preferred Development Plan has the highest ratepayer costs in all periods, but the gap narrows considerably over time. Morrison Park noted that if its model were to progress beyond 48 years, the ranking of the Preferred Development Plan likely would continue to improve in nominal dollar terms. However, depending on the discount rate selected, the Preferred Development Plan might never catch up to Plans 4, 5, and 6, as higher discount rates dramatically reduce the present value effect of results so far in the future.³⁴⁰

When considering ratepayer costs from an intergenerational perspective, Morrison Park concluded that the choice of plans is essentially immaterial to anyone who is likely to be a ratepayer only for the next 15 years. This would include older ratepayers or businesses that do not foresee a long-term future in the province as rates will increase under all plans. Past that point, however, the choice of plans can have a very significant impact, as ratepayer costs diverge.³⁴¹ Morrison Park's analysis reveals that "the

³³⁹ Exhibit MPA 3-1, p.24.

³⁴⁰ Exhibit MPA 3-1, p.24.

³⁴¹ Exhibit MPA 3-1, p.24.

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

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

9.11.0 Bill Impacts

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

³⁴² Exhibit MPA 3-1, p.24.

³⁴³ Exhibit MH-204, p. 197.

³⁴⁴ Exhibit LCA-3-3, p. 9S-10.

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

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

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

9.11.1. Impact on Lower Income and Vulnerable Consumers

Many witnesses and presenters expressed concern about the proposed rate increases. Dr. Higgin, an expert witness on behalf of CAC, noted that there was considerable “intergenerational inequity” associated with the proposed increases since ratepayers would have to wait a long time to benefit from more modest rate increases while paying much higher electricity bills in the short term (2015 to 2025). He described the short-term impact on ratepayers’ bills as “not acceptable”, particularly for lower income and vulnerable consumers.³⁴⁵ Dr. Higgin determined that vulnerable consumers³⁴⁶ who use electricity to heat their dwellings would see a 46.5% increase in their electricity bills over 10 years (2013 to 2023) under the Preferred Development Plan compared to 39.9% under the All Gas plan, as depicted in the following Table.³⁴⁷ Dr. Higgin defines

³⁴⁵ Exhibit CAC-76, p. 10.

³⁴⁶ Exhibit CAC-27, p. 55.

³⁴⁷ Exhibit, CAC-27, p. 55.

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

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

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

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

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

9.11.2. Impact on Northern and Aboriginal Customers

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

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

³⁴⁸ The Low income cut-off (LICO) represents a household income threshold where a family is likely to spend 20% or more of its income on food, shelter and clothing than the average family, leaving less income available for other expenses such as health, education, transportation and recreation. LICOs are calculated for families and communities of different sizes

³⁴⁹ Exhibit CAC- 31, p. 3.

³⁵⁰ Transcript, pp. 7865, 7867.

³⁵¹ Transcript, p. 7646.

³⁵² *The Manitoba Hydro Act*, C.C.S.M., c. H190. ss. 39(2.1), 39(2.2).

The Panel heard that residents of northern Manitoba face higher electricity bills because of the particularly harsh climate and their reliance on electricity as a heating source. It was pointed out to the Panel that customers in northern Manitoba do not have the range of heating fuels available to them that many customers in southern Manitoba do. Natural gas is not available in the north, leaving electricity or wood as the primary heating fuel options.

One northern resident described the sense of inequity felt upon seeing the homes of Manitoba Hydro employees in Gillam equipped with two electricity meters, one for heat and one for regular electricity use, and knowing that these employees do not have the same costs for electric heat. Some northern residents believe that Manitoba Hydro's northern employees receive free heat.³⁵³ While these employees do not receive free electric heat, the Panel learned that they do pay a much-reduced charge for this service. Manitoba Hydro confirmed that corporate homes for employees are fitted with two meters in order to separately meter electricity used for home heating. Employees pay a flat rate for heat based on the lowest average heating costs in Winnipeg, adjusted annually, and regular rates for electricity used for non-heating purposes.³⁵⁴ The Panel recognizes that this is an irritant for northern ratepayers, but Manitoba Hydro reported that this is a taxable benefit for its employees.

The Panel learned that affordability of electricity was a major concern for residential and general service customers in MKO First Nation communities. Most citizens of MKO First Nation communities fall into the low-income category and, like other lower income Manitobans, spend a greater percentage of their income on electricity than customers in higher-income categories. The Panel was told that rate increases would only exacerbate the lack of affordability demonstrated by the high levels of delinquent accounts in First Nations communities. Furthermore, these communities have no evidence that the federal government will raise its level of support to offset the projected rate increases.

In its presentation in Thompson on May 14, 2014, MKO indicated that 86% of MKO First Nation electricity accounts are currently in arrears. MKO called for greater access to DSM programs to help MKO customers to reduce their electricity bills and for the impact of future rate increases to be mitigated to the fullest extent possible. Of particular concern was the potential ineligibility of customers in arrears for Power Smart DSM programs.

³⁵³ Transcript, p. 8244.

³⁵⁴ Exhibit MH-181, p. 1.

MKO told the Panel that a significant number of customers in MKO First Nations continue to be affected by the projects and operations of Manitoba Hydro in the north. Manitoba Hydro makes mitigation payments to certain First Nations customers to compensate for these effects. The Panel heard that because Manitoba Hydro must recover the costs of mitigation payments through rates, the recipients of these payments are, in effect, paying for a portion of the mitigation payments they receive. To address this issue, MKO suggested that mitigation costs be removed from the rates that hydro-affected customers pay.

9.11.3. Impact on Commercial and Industrial Customers

Industrial and commercial (general service) customers provide 56% of Manitoba Hydro's domestic revenue from rates. The 17 largest industrial customers contribute some 22% of total domestic electricity revenue.³⁵⁵ Overall, industry pays up to 10% more in rates than it costs Manitoba Hydro to provide them with power.³⁵⁶

MIPUG presenters identified their main concerns with respect to electricity costs as stability of rates, ongoing transparent regulation of Manitoba Hydro's rates and major capital spending, and ensuring that rates for all customer classes reflect the cost of serving the class. One MIPUG presenter underlined that industry could expect to pay some \$400 million more over the next 20 years for the Preferred Development Plan compared to other viable alternatives. MIPUG also noted that rate increases of the magnitude and length proposed under Manitoba Hydro's Preferred Development Plan will be important considerations in future investment decisions, especially in deciding whether to expand and where expansions will take place, given competitive power rates in other jurisdictions.

The Panel was told that industrial customers have more flexibility than residential customers in their ability to respond to rate increases since, ultimately, they can take their business to jurisdictions with more competitive rates. The result would be a loss of these businesses in Manitoba.

9.12.0 Manitoba Hydro's Alternative Rate Methodologies

Manitoba Hydro's rate methodology for the NFAT analysis proposes even annual rate increases on the basis of reaching the 75/25 debt-to-equity target by 2031/32. After the debt-to-equity target is reached, the 1.20 interest coverage ratio would become the relevant target and rates increases would decline significantly.

³⁵⁵ Manitoba Hydro, Annual Report for the year ended March 31, 2013, pp. 48-49.

³⁵⁶ Exhibit MIPUG -28, p. 13.

Manitoba Hydro filed two alternative rate-setting methodologies with the Panel that would moderate the projected rate increases. According to Manitoba Hydro, these methodologies were provided as information for the Panel and do not indicate a policy change or yielding on its financial targets, but rather are a means of providing additional flexibility³⁵⁷ in relation to the amount of rate increases and the timing of reaching the financial targets.³⁵⁸

The alternative rate methodologies, which propose rate increases based on the interest coverage ratio, are described below:

Alternative Methodology One would maintain annual 3.95% rate increases for each development plan until the 1.20 interest coverage ratio was achieved followed by subsequent rates increases to maintain the 1.20 ratio. This alternative yields significantly on the debt-to-equity target, and only achieves debt-to-equity ratios in the order of 82% for the All Gas Plan (1) and 88% for the Preferred Development Plan (14) by 2031/32.³⁵⁹

Alternative Methodology Two is similar to Alternative Methodology One, with rate increases adjusted from 2016 to 2022 to minimize losses, followed by 3.95% annual rate increases until the 1.20 interest coverage ratio was achieved, and subsequently by rate increases to maintain the 1.20 ratio. Similar to Alternative One, Alternative Methodology Two represents financial scenarios that materially miss Manitoba Hydro's debt-to-equity target, and only achieve ratios in the order of 78% for the All Gas Plan and 86% for the Preferred Development Plan by 2031/32.³⁶⁰

The following Table shows the cumulative rate increases using Alternative Methodologies One and Two.³⁶¹

³⁵⁷ Exhibit MH-204, p. 188.

³⁵⁸ Exhibit MH-204, p. 188.

³⁵⁹ Exhibit MH-104-12-6, p. 2.

³⁶⁰ Exhibit MH-104-12-6, p. 3.

³⁶¹ Exhibit MH-104-12-6, pp. 1-3. [\MH-104-12](#)

Table 29 Cumulative Rate Increases at DSM Level 2, Using Alternative Methodologies and Reference Capital Cost

Manitoba Hydro Plans	2031/32		
	Base Methodology	Alternative Methodology One	Alternative Methodology Two
ALL GAS (1)	82%	54%	51%
K31/GAS (2)	88%	56%	53%
K19/GAS/750 MW (5)	94%	56%	53%
K19/GAS/750 MW (6)	95%	57%	53%
K19/C40/750 MW (12)	95%	57%	54%
Preferred Development Plan (14)	115%	70%	69%
Preferred Development Plan (14) (Pipeline Load)	115%	78%	76%

Under Alternative Methodology Two, in the medium term, most of the plans have cumulative rate increases in the range of 51%-54%, as compared to the Preferred Development Plan's 69%. This is significantly lower than the expected cumulative rate increases under Manitoba Hydro's base methodology.

9.13.0 Mitigating the Impact of Rate Increases

About 15% of Manitoba Hydro's annual gross revenue is paid to the Government of Manitoba for water rentals, debt guarantee fees, and capital tax. These direct payments are currently in the order of \$250 million annually and will double to over \$500 million for the Preferred Development Plan.³⁶² In addition, the Panel estimates that Bipole III in-service will result in incremental government revenue of over \$40 million annually. On an incremental Net Present Value basis, the total benefits to the Province are almost \$2.3 billion for the Preferred Plan compared to the All Gas Plan.³⁶³

Several witnesses commented on the scale of the relatively risk-free government benefits in relation to the rate increases and risks that ratepayers will face with export-oriented development plans. The Panel was told that the provincial government would see significant increases in payments from Manitoba Hydro under export-oriented development plans compared to plans designed to serve domestic need at a time when customers face the burden of rate increases and added risk.

³⁶² PUB/MH I-073a

³⁶³ Exhibit MH-171, p. 1.

A number of Interveners suggested ways for Manitoba Hydro or the Government of Manitoba to mitigate the impact of higher rates and the associated risks. MIPUG suggested that if Keeyask and the 750 MW transmission interconnection were to be pursued, Manitoba Hydro could adopt, for rate-setting purposes, lower debt-to-equity and interest coverage targets rather than adhering to a 75/25 debt to equity ratio target for at least the next two decades in order to bring rates for plans involving new hydro generation closer to the rate increases expected from the All Gas plan. MIPUG also called for the Government of Manitoba to reduce the impact on ratepayers by foregoing incremental government charges on the new projects for 15 years after their in-service dates.

MIPUG's expert witness provided an illustrative example of foregone government benefits that would make the Preferred Development Plan more beneficial for ratepayers than the All Gas Plan based on the 2012 estimates provided in the original NFAT Submission. In MIPUG's example, the present value of the foregone government benefits over the period to 2040 is \$1.398 billion (with no relief after that date), which amounts to approximately 60% of the benefit from water rentals, capital taxes and debt guarantee fees under Plan 14 (not including the other government benefits from higher taxes from the construction and other economic development arising from construction and operation.)³⁶⁴

Morrison Park provided the Panel with a recent example of risk sharing where the Government of Newfoundland and Labrador is absorbing a portion of the risk associated with the development of the Muskrat Falls generating station, which is being proposed to serve domestic and export markets.³⁶⁵

CAC recommended that the government create a Green Energy Benefit to mitigate the costs and risks associated with the export-oriented plants.

MKO suggested that the Government of Manitoba should consider broadening its current water rental sharing arrangements to include other MKO First Nations. It also suggested that additional consideration should be given to exempting hydro affected First Nations from water rental fees and mitigation costs. MKO also proposed a sharing of export revenues with affected communities.

³⁶⁴ Exhibit MIPUG-127, pp.1-3.

³⁶⁵ Transcript pp. 7392-7393.

9.14.0 Conclusions of the Panel

There is a requirement for Manitoba Hydro to provide safe and reliable electricity service, and that this includes investments in new generation, as well as replacement of aging infrastructure. As a result, all proposed development plans would require increases in electricity rates above the rate of inflation. In that regard, Manitoba is no different than other Canadian jurisdictions, which project substantial rate increases in the imminent future.

All development plans presented could lead to higher-than-projected rate increases under several scenarios, including (1) capital costs higher than forecast, (2) interest rates rising above forecast levels, (3) export prices being lower than what is forecast, or (4) drought conditions which limit export quantities. All other things being equal, any single one of these risk factors would result in higher rate increases than projected. Ratepayers are shouldering each of these risks. In comparison, the capital tax and water rental fees realized by the Government of Manitoba are relatively risk-free.

It would be reasonable for the Government of Manitoba to give serious consideration to a reduction of incremental provincial benefits from the Keeyask Project. This should involve the Government directing a portion of its incremental capital taxes and water rental fees to be used to mitigate the impact of rate increases on lower-income customers, as well as northern and aboriginal communities.

Manitoba Hydro can contribute to the impact of rate increases in two ways. It can relax its 75/25 debt-to-equity ratio policy to moderate its proposed electricity rate increases. Manitoba Hydro should also mitigate rate increases by seeking to reduce its own expenditures through operational savings.

The development of the Conawapa Project would result in even higher ratepayer commitments to 50 years, after which the rate increases are not as great as other options. Based on current circumstances, the risks related to Conawapa's development far exceed any rewards to ratepayers over the next 50 years. It would not be prudent to continue spending money on Conawapa. The Panel also notes the importance of sunk costs and their impact on rates, particularly when those costs have to be written off.

10.0.0 Risk and Uncertainty

10.1.0 Introduction

Manitoba Hydro identified a number of risks inherent in the Preferred Development Plan and alternative plans. In estimating the expected Net Present Value of different plans, it is necessary to make assumptions about the likely future values of critical economic variables (the reference case) and then conduct a sensitivity analysis in order to test the vulnerability of the reference case outcomes to different risk factors. For example, Manitoba Hydro's load forecast is based on a number of assumptions about population and economic growth in the province. If this forecast growth is not realized, new generation assets will be oversized for actual load. Similarly, if energy prices are lower than forecast by Manitoba Hydro, then electricity export revenues will be less than expected and will result in higher domestic rates to make up for the shortfall.

There are a number of risk factors facing Manitoba Hydro and its ratepayers:

- Energy prices;
- Assumptions for a recovery of U.S. demand to pre-2008 levels;
- The future price of natural gas;
- The development of a carbon price regime in the U.S.;
- Assumptions regarding coal retirements;
- Discount rate and interest rates;
- Load forecast and Demand Side Management;
- Construction costs;
- Climate change and drought;
- Drought impacts and mitigation;
- U.S. transmission interconnection approval;
- Financial impact to the Province of Manitoba; and
- Risk impact on ratepayers compared to risk impacts on the Province.

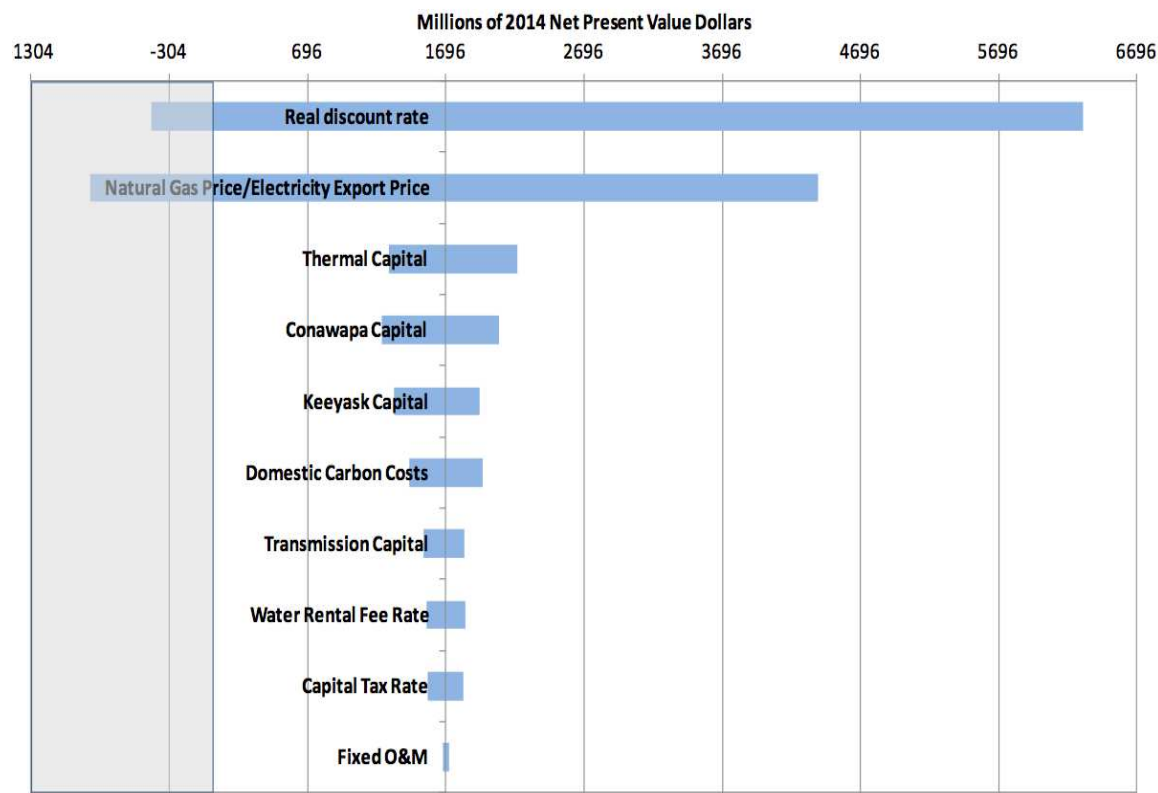
Any planning process must consider the risk that the assumptions regarding key economic variables may not be accurate. This problem is magnified by the lengthy planning horizon over which Manitoba Hydro conducted its economic analysis and financial analysis (78 years and 50 years, respectively). As the time period lengthens,

forecasting future trends in such factors as load growth, energy prices, interest rates and capital costs becomes more difficult and the results more uncertain. As a result, the Preferred Development Plan and alternative plans are subject to a significant level of risk and uncertainty in meeting their expected economic and financial outcomes.

10.2.0 Identification and Ranking of Risk Factors

With respect to the Preferred Development Plan, Manitoba Hydro identified the ten risk factors and their range of uncertainty from low to high. For the purpose of its uncertainty analysis, Manitoba Hydro grouped the high impact factors into three categories: (1) economic indicators (primarily the discount rate), (2) energy prices (both electricity export and natural gas prices), and (3) capital costs. The following Tornado diagram lists the factors from highest to lowest impacts.³⁶⁶

Figure 22 Tornado Diagram Showing Sensitivity of the Preferred Development Plan to Different Risk Factors



Source: Manitoba Hydro NFAT Submission, Chapter 10, Figure 10.1, p. 4

³⁶⁶ Manitoba Hydro NFAT Submission, Chapter 10, p. 4.

Other factors were identified, but not separately analyzed, as they did not appear to have a material impact on the relative benefits of evaluated alternative plans. Manitoba Hydro determined that certain plans were affected differently by the three identified factors.

In addressing risk, Manitoba Hydro performed an assessment to determine which risk factors had the highest impact on the economic and financial outcomes. After identifying the most critical risk factors, Manitoba Hydro undertook an uncertainty analysis, defined by “reference” values as well as “low” and “high” values for these factors. They were then formulated into 27 different scenarios, each of which was analyzed for its probability.

For the All Gas Plan, the discount rate was the foremost factor affecting its Net Present Value. At a low discount rate, there is a significant negative impact on its incremental Net Present Value, while a high discount rate would give it a comparative advantage over more capital-intensive plans. The All Gas plan is also exposed to future gas prices, as the commodity cost of gas is an input into the generation cost.

For the Preferred Development Plan, the opposite effect is the case. It is a capital-intensive hydro project with a large upfront capital cost and attendant revenue requirement to recover these costs over the long-term. The Preferred Development Plan is, therefore, affected more negatively by higher discount rates, which would dilute the long-term benefits from the Plan that occur fairly late in the 78-year study period. Conversely, a lower discount rate improves the benefits associated with the Plan.

Manitoba Hydro indicated that overall, the Preferred Development Plan is most affected by energy prices, but has significant exposure to both discount rate and capital cost escalations. In plans with a mix of new gas and hydro resources, such as Plan 5, the impact of the three factors is moderated. The diversity provided by the mix of hydroelectric and natural gas-fired resources balances the effect of the factors and limits the significance of their effect on incremental Net Present Value.³⁶⁷

10.2.1. Energy Prices

Manitoba Hydro's Preferred Development Plan relies on exports of power surplus to domestic needs through firm long-term contracts, shorter-term firm sales, and opportunity sales of surplus energy on the spot market. The primary market for Manitoba Hydro's exports is the MISO market. The greatest uncertainty in modeling export markets is the level of forecasted export market prices. These prices are subject

³⁶⁷ Manitoba Hydro NFAT Submission, Chapter 10, p. 7.

to a number of different factors, including U.S. demand for electricity, the prices of competing generation sources, and whether or not a carbon tax will materialize in the U.S. Potomac Economics performed an analysis of the Midcontinent Independent System Operator (MISO) market and a review of Manitoba Hydro's export market price projections, which is discussed in further detail in Chapter 6.

Manitoba Hydro has included capacity pricing premiums in its export price forecast. Independent Expert Consultant, Potomac Economics, has suggested that this represents a substantial risk to Manitoba Hydro and that its capacity revenues may be much lower than expected. When there are capacity surpluses in the MISO region, the capacity market pricing may be much lower than expected.

In modelling the uncertainty around energy prices, Manitoba Hydro utilized six independent commercially available forecasts for electricity, natural gas, and carbon prices. Natural gas prices and carbon prices were assumed to be independently uncertain. Electricity prices were assumed to be deterministically dependent on the natural gas and carbon prices.

Export prices in the U.S. MISO market are influenced by the least costly generation alternative. Currently, electricity prices in MISO are set by the cost of coal-fired generation over 90% of the time and during virtually all of the off-peak hours. The rest of the time, the MISO market price is set by a combination of the cost of Combined Cycle Gas Turbine (CCGT) and Simple Cycle Gas Turbine (SCGT) natural gas-fired generation.³⁶⁸

Overall, Manitoba Hydro's energy price assumptions are directly influenced by four factors: (1) a recovery in the export market demand to pre-2008 levels (before the financial crisis); (2) trends in the future price of natural gas, especially shale gas; (3) the near-term development of a carbon price regime in the U.S.; and (4) retirements of coal-fired generating stations in the MISO area.

10.2.2. Assumptions for a Recovery of U.S. Demand to Pre-2008 Levels

The 2008 financial crisis in the U.S. resulted in electricity demand being significantly depressed, compared to pre-2008 levels. While the economy has since recovered, an issue that was raised repeatedly before the Panel was whether there has been a structural shift that has permanently altered the nature of the relationship between economic growth and load growth in the U.S. economy. CAC's witness, Dr. Gotham,

³⁶⁸ Manitoba Hydro NFAT Submission, Chapter 5, pp. 45-46.

noted that there was significant unresolved uncertainty regarding this issue.³⁶⁹ Notably, despite the recovery in the U.S. economy, Manitoba Hydro has experienced five years of average export prices in the MISO region in the 3¢/kWh to 3.5¢/kWh range, with no apparent upward trend in market prices.³⁷⁰

Elenchus noted the potential for structural change to the electricity market as a result of new technology, suggesting that forecasting, by its very nature, does not assume or account for such structural change. Potential issues of concern would be the widespread adoption of electric vehicles, which would increase demand, or alternatively grid parity of alternative generation sources such as solar power that would lower demand. In Elenchus' view, the uncertainty is not whether such change will happen, but when.³⁷¹ If (or when) the cost of distributed and/or micro-generation and storage declines to the point of grid parity, there could be a tipping point where industrial, commercial, and even residential customers switch en masse from grid power to self-generation.³⁷² This would allow consumers to price-competitively generate a portion or all of their electricity and reduce their reliance on the grid.³⁷³

Morrison Park and other witnesses also noted that while the timing and impact of changes would likely be gradual, long-lived assets, such as those included in the Preferred Development Plan, may become locked in. This means the utility would forego the possibility of adopting new, more inexpensive technology.³⁷⁴ CAC further quoted Mr. Campbell, the CEO of Ontario's Independent Electricity System Operator, who spoke to the potential for fundamental change across the electricity sector, stating that:

*Take these four points together: cheaper solar power, cheaper energy storage, more internet-connected devices, and low voltage DC power-networks offering alternative ways to distribute your home-grown energy sources to devices in your home. Somehow this is all starting to feel like very fundamental change across our sector.*³⁷⁵

For Manitoba Hydro, the risk of structural change is two-fold. First, it could reduce demand in Manitoba, resulting in decreased revenues from Manitoba customers. Second, it could depress export prices or complicate the renewal of export contracts,

³⁶⁹ Transcript, p. 8429.

³⁷⁰ Exhibit PUB-58-1, pp. 45, 63.

³⁷¹ Exhibit ERA-3, p. ii, 42.

³⁷² Exhibit ERA-3, p. 41.

³⁷³ Exhibit ERA-3, p. i.

³⁷⁴ Exhibit MPA-3, p. 74.

³⁷⁵ Exhibit CAC-91, p.19.

thus reducing export revenues. In the Panel's view, the worst-case scenario could lead to so-called stranded assets for which Manitoba Hydro cannot recover all of its costs through domestic and export revenues.

10.2.3. The Future Price of Natural Gas

Less than 10 years ago, natural gas prices were at all-time highs. Since then, prices have dropped by approximately 50% due to the advent of shale gas economically produced through hydraulic fracturing, or "fracking" technology. CAC noted the transformative effects of shale gas upon the U.S. marketplace and called it a "game changer."³⁷⁶

Natural gas prices are a significant cost input into gas-fired generation that sets the price point in MISO during on-peak periods. Continuation of low gas prices has the potential to significantly lower Manitoba Hydro's export revenues. Continued low gas prices may also affect domestic electricity demand for space-heating purposes if customers realize they can drastically reduce their heating bills by switching to gas furnaces and water heaters. This could reduce domestic demand for electricity.

10.2.4. The Development of a Carbon Price Regime in the U.S.

Hydroelectric energy does not result in any significant carbon dioxide (CO₂) emissions. Conversely, coal-fired generation and, to a lesser extent, gas-fired generation, results in significant emissions. According to the U.S. Environmental Protection Agency, average CO₂ emissions for coal are 1.02 tonnes/MWh, while emissions for gas are around 0.5 tonnes/MWh.

To date, the U.S. does not have a carbon tax or cap-and-trade mechanism. However, there is a widespread expectation that the U.S. will eventually implement legislation, although both the timing and magnitude of any tax or emissions restrictions is uncertain. Should such a regime be eventually introduced, the economic competitiveness of low-emission hydroelectricity will increase vis-à-vis coal- and gas-generated electricity, as the latter two would become more expensive due to the cost of emissions.

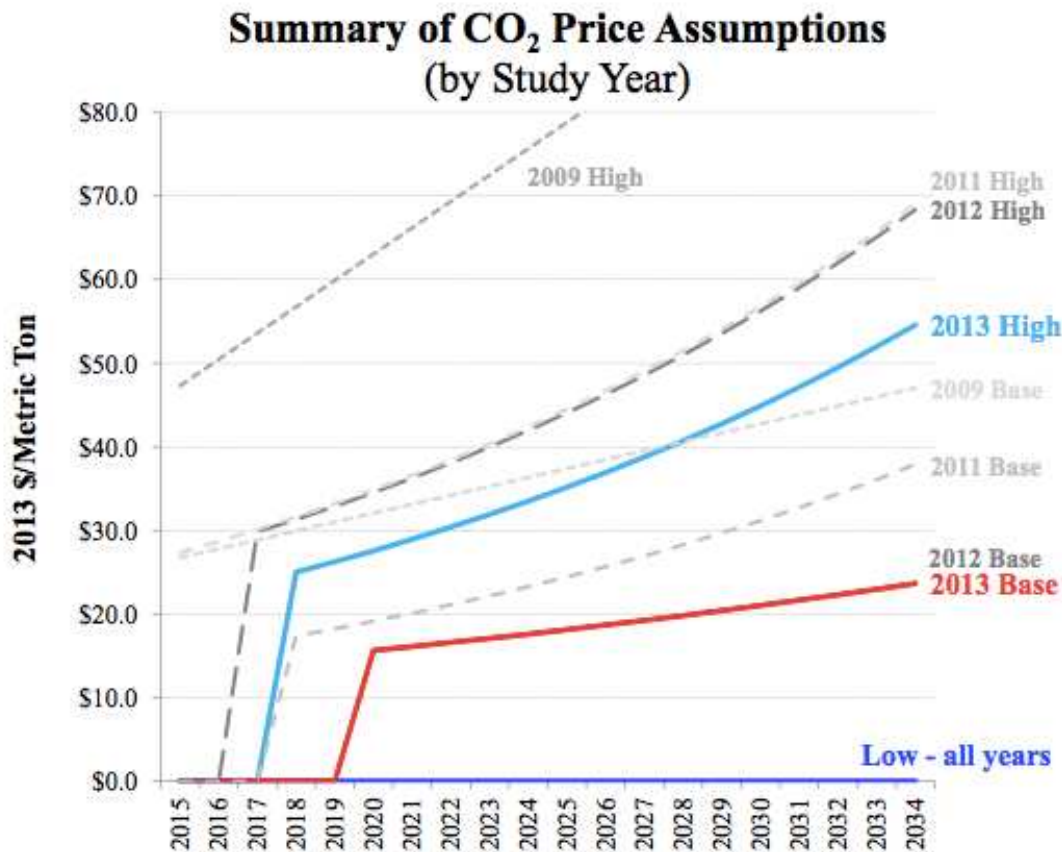
Dr. Murphy of the Brattle Group indicated that while less than a decade ago there was an expectation for a carbon regime in the relatively near term, the global recession "knocked that train off the rails."³⁷⁷

³⁷⁶ Exhibit CAC-91, p. 11.

³⁷⁷ Transcript, p. 2247.

Manitoba Hydro filed on the public record the Brattle Group's forecast, which assumes carbon prices starting at \$15/ton (U.S.) in 2020, growing to \$21/ton in 2030, and reaching \$24/ton by 2034.³⁷⁸ The Brattle Group also observed that over the past several years, carbon price assumptions have both pushed back the expected implementation date and reduced the expected carbon price. This is illustrated in the following diagram by the Brattle Group, which highlights the importance of both the level and timing of carbon pricing to export price forecasts:

Figure 23 Brattle Group Summary of Current and Historic Carbon Price Assumptions



In an in-camera session, the Panel had the opportunity to examine the various carbon price assumptions made by Manitoba Hydro's commercial forecasters. In addition, MNP provided evidence regarding its own pricing assumptions. Overall, it became clear that there is significant uncertainty about the development and nature of a carbon regime. In the Panel's view, there is no clear consensus on what level (if any) of carbon pricing should be employed.

³⁷⁸ Exhibit POT-2-1, p. 10.

MNP assigned a 50/50 probability that a carbon tax regime would develop. Potomac Economics provided a reference forecast with a carbon tax commencing in 2021 and one reference forecast without a carbon tax regime. Potomac indicated both outcomes are equally as likely but will ultimately depend on the direction of future policy in the U.S.³⁷⁹ CAC's witness, Dr. Gotham, stated that the development of a carbon regime is a binary proposition and essentially a "yes" or "no" question, with a significant difference in electricity market pricing between the two.³⁸⁰

Since Manitoba Hydro's export revenue forecast is premised on the development of a U.S. carbon regime, the failure of such a regime to develop could, in the Panel's view, significantly lower actual export revenues realized by Manitoba Hydro, and as such represents a significant risk in its assumptions. The uncertainty surrounding this forecast is significant, as La Capra Associates indicated that a slightly lower view of export market prices substantially erodes the economic benefits of the Preferred Development Plan.³⁸¹

10.2.5. Assumptions Regarding Coal Retirements

As set out above, coal-fired generation sets the MISO market price, especially during off-peak hours. A retirement of coal-fired generating stations would likely lead to the replacement with higher-cost sources, such as natural gas generation. This could result in rising MISO electricity prices, and hence increased revenues achieved by Manitoba Hydro.

The Brattle Group forecasts from 11 to 16 GW of MISO coal plant retirements in the coming years. This level of MISO coal plant retirements is substantially above the level assumed by Potomac Economics in its reference case. Potomac assumes 6 GW of coal plant retirements in the MISO region. Potomac opined that the emissions and fuel cost assumptions along with the high level of coal plant retirements assumed by the Brattle Group overstate energy prices.³⁸²

10.2.6. Discount Rate & Interest Rates

The discount rate in the economic evaluation context is designed to reflect the return that markets require on the type of investment in question. Discount rates and interest rates are linked, as interest rates influence Manitoba Hydro's cost of borrowing. To the extent that interest rates increase the future the cost of borrowing, it will be reflected in a

³⁷⁹ Exhibit POT-2-1, p. 45.

³⁸⁰ Transcript, p. 8562.

³⁸¹ Exhibit LCA-3, p. LCA-27.

³⁸² Exhibit POT-2-1, p.11.

higher discount rate. Such circumstances would increase both the cost of borrowing incurred by Manitoba Hydro, as well as the discount rate used to evaluate the development plans. Higher discount rates have a negative impact on the finances and economics of capital-intensive plans with high up-front costs such as the Preferred Development Plan, because the long-term benefits are highly discounted.

Manitoba Hydro used a “weighted average cost of capital” (WACC) approach. This approach is premised on Manitoba Hydro’s target 75/25 debt-to-equity ratio. The debt portion is based on Manitoba Hydro’s cost of borrowing, including the debt guarantee fee it pays to the Province of Manitoba. For the equity component, which constitutes 25%, Manitoba Hydro added a 3.00% return on equity. In its original filing Manitoba Hydro’s WACC discount rate was 5.05%. In its 2013 update, the WACC discount rate increased to 5.40% as a result of increased borrowing costs.

Manitoba Hydro assumed long-term interest rates of 4.50% for 2014, rising to 6.75% for 2019 onwards. Changing these interest rate assumptions will raise or lower the projected interest costs to be incurred by Manitoba Hydro, and will have a strong impact on its finances.

Morrison Park conducted an interest rate sensitivity analysis of the impact on the total costs to Manitoba ratepayers.³⁸³ They indicated that interest rates have some clear impacts on total cost to Manitoba ratepayers. For Plan 5, a 1% increase in interest rates causes the Net Present Value (at a 6% discount rate) of Manitoba ratepayer costs to rise by approximately 6.5%. For the All Gas Plan, this sensitivity is only 4.5%, while for the Preferred Development Plan the sensitivity is 9.5%.

Changes in interest rates have the greatest impact on the Preferred Development Plan, which employs the greatest amount of debt. Conversely, interest rates have the least impact on the All Gas Plan, which employs the least amount of debt.³⁸⁴

La Capra Associates also measured the impact on the economics of the Preferred Development Plan of the increase from Manitoba Hydro’s 2012-assumed WACC of 5.05% to the 2013-assumed WACC of 5.40%. According to La Capra, the change in discount rate reduced the \$1.7 billion Net Present Value of the Preferred Development Plan by \$663 million.³⁸⁵ Given that this was a relatively minor change in the assumed discount rate, it is clear that the Preferred Development Plan is highly sensitive to

³⁸³ Exhibit MPA 3-1, p. 20.

³⁸⁴ Exhibit MPA 3-1, p. 19.

³⁸⁵ Exhibit LCA-45, p.16.

discount rates. Plans involving only the Keeyask Project are still affected, but are less susceptible to discount rate risk due to less capital being committed.

10.2.7. Load Forecast and Demand Side Management

The Panel heard evidence of potential new industrial load in the pipeline sector, which can add approximately 1,300 GW of incremental energy load that is currently not included in the 2013 base load forecast. If the pipeline load materializes, this will increase pressure on Manitoba Hydro to achieve its Demand Side Management targets, as it will reduce the available generation surplus. However, advancing the construction of the Keeyask Project to 2019 mitigates this risk by providing additional surplus capacity.

Manitoba Hydro's latest load forecast assumes that enhanced DSM based on the 2014 Power Smart Plan will achieve over 3,900 GWh of energy savings, as well as over 1,100 MW in capacity savings.³⁸⁶ This level of DSM is greater than the dependable energy output of the Keeyask Project. If the savings are not realized, this will have financial implications for Manitoba Hydro and will affect the timing requirement for other new generation.

In the long term, Manitoba Hydro's load forecast is significantly more uncertain, as it does not account for the development of new technologies that could either significantly increase or decrease electricity consumption. This could include the development of grid parity with respect to technologies such as solar photovoltaic cells or the proliferation of electric vehicles.

10.2.8. Construction Costs

Higher construction costs for Keeyask and Conawapa are a major risk facing the Preferred Development Plan. La Capra Associates stated that modest increases in capital cost assumptions for these projects would result in other development plans having lower costs than the Preferred Development Plan even over the 78-year evaluation period.³⁸⁷ This was highlighted by the effect of a relatively modest capital cost increase noted in 2014. During the NFAT Review, Manitoba Hydro filed updated costs for Keeyask and Conawapa that increased the cost of Keeyask by close to \$300 million and the cost of Conawapa by nearly \$500 million from 2012 levels.³⁸⁸ La Capra Associates determined a reduction in incremental Net Present Value of the Preferred

³⁸⁶ Exhibit MH-180, pp.55-56.

³⁸⁷ Exhibit LCA-3, p. LCA-27.

³⁸⁸ Exhibit MH-113.

Development Plan by \$871 million or over 50% of its benefit compared to the All Gas Plan.³⁸⁹

Morrison Park prepared a domestic revenue sensitivity analysis showing the Net Present Value (2015-2062) impact on ratepayers of a \$1 billion increase in the capital cost of each of Keeyask and Conawapa. Morrison Park noted that the results of a \$1 billion increase in capital costs were very similar to the impact of higher interest rates. Adding \$1 billion to the construction costs of Keeyask causes Plan 5's Net Present Value (at 6%) of ratepayer costs to rise by slightly less than 3%. At this level, the All Gas Plan is approximately 2% superior to Plan 5 (or the other plans including Keeyask in 2019). Morrison Park also indicated that the analysis showed that the Preferred Development Plan was inferior, requiring higher domestic revenues compared to all other plans if both Keeyask and Conawapa construction costs are increased.³⁹⁰

10.2.9. Climate Change and Drought

Manitoba Hydro's primarily hydraulic generating facilities rely on adequate water flows being available. Plans that rely on either Keeyask or Conawapa are therefore subject to a greater risk of climate change and droughts.

Manitoba Hydro conducted an economic sensitivity analysis to see how various potential hydrological changes due to the effects of climate change would affect the economic analysis of some representative portfolios. However, Manitoba Hydro did not indicate any directional impacts of climate change.

La Capra Associates and MNP were critical of Manitoba Hydro's climate modeling and Manitoba Hydro's failure to quantify the impact of climate change on the severity of droughts.³⁹¹ According to La Capra Associates, Manitoba Hydro's Global Climate Model only models long-term average stream flows rather than dealing with specific annual flows. As a result, in a severe drought the long-term flows are "hardwired" into this analysis without being adjusted.³⁹² In La Capra Associates' view, this means that the impact of climate change is essential "assumed away" in the analysis.

Manitoba Hydro engaged the Ouranos Consortium on Regional Climatology and Adaption to Climate Change (Ouranos)³⁹³ to assist with modeling the impact of climate

³⁸⁹ Exhibit LCA-45, p. 16

³⁹⁰ Exhibit MPA-3-1, p. 21.

³⁹¹ Exhibit LCA-7, p. 4-11.

³⁹² Exhibit LCA-7, p. 4-12.

³⁹³ Ouranos was created in 2001 as a joint initiative of the Quebec Government, Hydro-Quebec and Environment Canada. The consortium brings together 450 scientists and professionals that have considerable experience in climate change impacts and adaptation including a focus on energy supply and water resources.

change on the Manitoba hydrology. Dr. Roy of Ouranos testified that he did not agree with the concerns raised by the Independent Expert Consultants. He indicated the state of knowledge on climate change and drought remains inconclusive, since there is no consensus in the scientific community with respect to quantitative impacts of climate change on droughts. Dr. Roy further noted that given the current state, Manitoba Hydro's consideration of the worst drought in its historical record was the best approach to be used at this time.³⁹⁴

However, Manitoba Hydro did not utilize the worst drought on record, choosing instead to use the 5-year historical drought from 1987/88 to 1991/92. Manitoba Hydro indicated that this was an appropriate drought to be utilized, as it is representative of a post-Lake Winnipeg Regulation scenario. Lake Winnipeg Regulation, which came into effect in the 1970s, requires Manitoba Hydro to keep the level of Lake Winnipeg between a certain minimum and maximum, subject to conditions.

Manitoba Hydro has experienced at least four multi-year drought situations in the last 99 years, namely:

Table 30 Historical Droughts Experienced in Manitoba

Historical Period	Duration of Drought
1929 -1933	5 Years
1935 - 1942	7 Years
1981 - 1985	5 Years
1988 - 1992	5 Years

Morrison Park illustrated that a prolonged drought such as the worst on record, which occurred from 1929 to 1942, when Manitoba Hydro experienced an extended period of below-average flows for 12 of 14 years, would have a large impact on retained earnings, and require a lengthy recovery period.³⁹⁵ The recovery period would be much greater for the Preferred Development Plan versus the All Gas Plan.

Morrison Park did an analysis of the 1929 to 1942 period, superimposed on lower water flows based on 90% of the long-term average flows. While the long-term implications of a drought were similar for the Preferred Development Plan and the alternative plans, over the term of the drought, the Preferred Development Plan would require larger rate increases.

³⁹⁴ Transcript, pp.1907-1908.

³⁹⁵ PUB/MPA 027(a)-(c).

10.2.10. Drought Impacts and Mitigation

The biggest risk with respect to a prolonged drought is not that Manitoba's electrical demand cannot be met, but that Manitoba Hydro could suffer significant, adverse financial consequences in meeting both domestic and export contract obligations. Manitoba Hydro measured its drought risk based on the impact of a 5-year drought. The timing of a potential drought could directly affect Manitoba Hydro's retained earnings. For the Preferred Development Plan, a 5-year drought commencing in 2014/15 would reduce retained earnings by \$1.2 billion. For a drought commencing in 2021/22 (when Keeyask is in service) the impact increases to \$2.1 billion, and for one commencing in 2027/28 (when both Keeyask and Conawapa would be in-service), the impact would increase to \$2.3 billion. The magnitude of the impact of droughts is similar for alternative plans including the All Gas Plan or one without Conawapa because Manitoba Hydro's system is predominantly hydro based.³⁹⁶

According to Morrison Park, in a prolonged 20-year period of low water flows similar to the 20-year period of high water flows Manitoba Hydro has just experienced, there is a risk that a portion of Manitoba Hydro's debt could become "stranded." This means that Manitoba Hydro would no longer be able to make full debt payments.³⁹⁷ Since Manitoba's electricity system is virtually completely hydro-based, this risk exists regardless of whether the Keeyask Project or a gas facility is chosen.³⁹⁸ If the Province of Manitoba had to start servicing this debt pursuant to its guarantee, this could be seen as a government subsidy of Manitoba Hydro.³⁹⁹ However, because the Conawapa Project would increase Manitoba Hydro's debt by an additional \$10 billion, it would increase the sensitivity to a prolonged drought.⁴⁰⁰ In Morrison Park's assessment, the upper boundary of potentially stranded debt would be approximately \$10 billion, and having the Province of Manitoba service such debt could be seen as a tax-supported subsidy of Manitoba Hydro.⁴⁰¹

Manitoba Hydro took issue with Morrison Park's financial model used to determine financial distress. Manitoba Hydro suggested that Morrison Park's calculations would tend to overstate gross interest expense, understate net income, and understate the gross interest coverage ratio in some years. That would overstate the amount of stranded debt in some years.⁴⁰²

³⁹⁶ PUB/MH I-205 (Revised).

³⁹⁷ Transcript, pp. 7289-7292.

³⁹⁸ Transcript, p. 7292.

³⁹⁹ PUB/MPA 27(c), p. 23.

⁴⁰⁰ Transcript, p. 7292.

⁴⁰¹ PUB/MPA 27(c), p. 23.

⁴⁰² Exhibit MH-204, p. 198.

Aside from the possibility of rate increases greater than currently budgeted for by Manitoba Hydro, there are other drought mitigation options. Morrison Park suggested that the establishment of a drought contingency fund of sufficient size to offset all water rental fees and capital taxes for three years in the event of a severe drought would provide insurance against a significant level of financial distress.⁴⁰³

As experienced by Manitoba Hydro in 2004, droughts can lead to significant year-over-year rate increases both during and immediately following the drought. These rate increases become imbedded in Manitoba Hydro's future revenues.

10.2.11. U.S. Transmission Interconnection Approval

The Great Northern Transmission Line, in which Manitoba Hydro has an ownership and a financial stake, is a project being advanced by Minnesota Power. In order to proceed, this project requires a Certificate of Need from the Minnesota Public Utilities Commission (MPUC). If the transmission line is not approved by the MPUC and Manitoba Hydro has committed to the construction of Keeyask for an in-service date of 2019, Manitoba Hydro would have to rely on existing transmission to deliver Keeyask generated power to market. If the line receives permitting and is built, it will allow for expanded exports and have the added benefit of reducing drought risk by increasing import capabilities.

10.2.12. Financial Impact to the Province of Manitoba

The preceding risk issues all have the potential for reducing Manitoba Hydro's net income in the post-Keeyask construction time frame. A combination of downside risks, which involve higher capital cost, coupled with lower export prices and below average flow years, could result in consecutive annual net losses for Manitoba Hydro. Because the Province must show Manitoba Hydro's losses on its financial statements, and will experience lower water rental revenues during a drought, it is likely that Manitoba Hydro would seek higher rate increases to ensure positive net income.

10.2.13. Risk Impact on Ratepayers Compared to Risk Impacts to the Province

Depending on the direction of the risks set out above, ratepayers can either lose or benefit, since Manitoba Hydro's rates are set on a cost-of-service basis. To the extent that Manitoba Hydro's costs cannot be recovered from export revenues, they must be recovered through domestic rates. Ratepayers accordingly would face the risk of higher-

⁴⁰³ PUB/MPA 27(c), p. 26.

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

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

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

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

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

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

10.3.0 Conclusions

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

⁴⁰⁴ Exhibit MIPUG-9, p. C-46.

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

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

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

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

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

Manitoba Hydro continues to be subject to drought risk, specifically in the face of prolonged low water flows. The primary risk is not that Manitoba Hydro could not meet domestic demand, but rather that its financial situation would erode. This could require rate increases beyond what is currently budgeted. In the absence of such rate increases, there is a risk that the Province of Manitoba might have to step in to assume

a portion of Manitoba Hydro's debt. From a reliability perspective, the 750 MW U.S. transmission interconnection would mitigate drought risk by providing enhanced import capacity.

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

11.0.0 Socio-Economic Impacts

11.1.0 Introduction and Background

The Economic Evaluation, outlined in Chapter 8, considers only the net economic benefits of various development plans, and does so only from the perspective of Manitoba Hydro. The Panel's Terms of Reference also directed it to consider a broader range of social and economic effects and to determine whether the Preferred Development Plan provides the highest level of overall socio-economic benefit to Manitobans.

Recognizing the broad nature of socio-economic impacts and benefits, the Panel first sought to define the scope of its inquiry. In consultation with Manitoba Hydro and the Interveners, the following definition was developed:

"A critical analysis of the socio-economic impacts and benefits of Manitoba Hydro's Preferred Development Plan and alternative plans. Specifically, a high level summary of potential effects to people in Manitoba, especially Northern and Aboriginal communities, including such things as employment, training and business opportunities; infrastructure and services; personal, family and community life; and resource use."⁴⁰⁵

Manitoba Hydro's examination of these issues was limited in scope, largely restricted to four considerations:

- A qualitative assessment of the environmental and socio-economic benefits of a limited set of different resource technology options, including hydro, wind, Demand Side Management (DSM) and natural gas;
- An economic impact analysis of the Preferred Development Plan;
- A more detailed analysis of expected socio-economic benefits of the Keeyask Project; and
- A Multiple Account Benefit Cost Analysis (MA-BCA) to determine the net benefits accruing to various stakeholders (accounts), including Manitoba Hydro, the Government of Manitoba, ratepayers, aboriginal communities and the Manitoba economy in general.⁴⁰⁶ The MA-BCA analysis was limited to a comparison of the Preferred Development Plan to three other plans: Plan 1/All Gas; Plan2/K22/Gas; and Plan 4/K19/Gas24/250MW.

⁴⁰⁵ Exhibit PUB-10, p.14.

⁴⁰⁶ Manitoba Hydro NFAT Submission, Chapter 13, p. 2.

This chapter reviews each of these four components of Manitoba Hydro's socio-economic evaluation and the limitations of the analysis presented during the NFAT Review. The Panel heard concerns that Manitoba Hydro's approach and the small number of plans that it considered did not provide a thorough socio-economic evaluation. Specifically, while there is an in-depth analysis of the Keeyask Project and its impact on aboriginal and northern communities, there is much less assessment of the benefits and impacts of other alternatives or other generation sources.⁴⁰⁷

11.2.0 Qualitative Assessment of Resource Technology Options

11.2.1. Manitoba Hydro's Screening of Resource Technology Options

In developing the Preferred Development Plan and alternative plans, Manitoba Hydro began by considering 16 utility-scale resource technology options to meet anticipated load growth. These included DSM, hydro, natural gas, coal, nuclear, wind, solar, geothermal, biomass, and imports. The viability of different resource options were then assessed according to: a) technical characteristics, including the intermittency and seasonality of supply; b) environmental characteristics, such as greenhouse gas emissions and other potential environmental harm; c) social and policy characteristics, such as regulatory constraints and "social acceptability"; and d) economic characteristics.

On this basis, Manitoba Hydro ruled out geothermal, biomass, nuclear, and solar as viable resource options and limited its consideration to resource plans that included DSM, hydro, wind, natural gas, and imports.

For the purposes of its socio-economic analysis, Manitoba Hydro prepared the following overview of a specific set of socioeconomic considerations associated with six resource options: DSM, the Keeyask Project, the Conawapa Project, on-shore wind, simple cycle gas turbines, and combined cycle gas turbines.⁴⁰⁸

⁴⁰⁷ Exhibit MMF-26, pp. 7-8.

⁴⁰⁸ Manitoba Hydro NFAT Submission, Chapter 7, p. 39.

Table 32 Socioeconomic Screening of Generation Technologies

	DSM	Keeyask	Conawapa	Wind	Heavy Duty CCGT	Heavy Duty SCGT
Health Concerns	-	Very Low	Very Low	Low	Low	Low
Safety Concerns	-	Medium	Medium	Very Low	High	High
MB Business Opportunities (% of capital spent in MB)	100%	53%	46%	18%	30%	17%
Employment Direct Construction	Program Dependent	4480 Person- Years	6650 Person- Years	35 to 80 Person- Years	329 Person- Years	116 Person- Years
At Northern Work Sites	Program Dependent	94%	94%	0%	0%	0%
Permanent O&M	Minimal	58 FTE	61 FTE	4 to 8 FTE	94 FTE (for 1 to 2 plants at site)	52 FTE (for 1 to 4 plants at site)
At Northern Work Sites	0%	100%	100%	0%	0%	0%
Royalties / Taxes (2014\$) Water Rentals	-	\$9.0 M/year	\$12.8 M/year	-	-	-
Capital Taxes	Program Dependent	\$17.3 M/year	\$28.6 M/year	\$0.8 M/year	\$2.0 M/year	\$0.8 M/year
Guarantee Fees	Program Dependent	\$27.7 M/year	\$45.8 M/year	Potential for \$1.3 M/year	\$3.2 M/year	\$1.3 M/year

Aside from this very general qualitative overview, no aspects of the socio-economic impacts and benefits of DSM or wind options received further attention. Instead, Manitoba Hydro's analysis focussed on the socio-economic impacts on the Preferred Development Plan and a MA-BCA analysis restricted to four development plans that included only hydro and gas resource options.

11.2.2. Considering the Employment Benefits of Other Options: Wind and Demand Side Management

There was limited analysis of the employment opportunities and benefits associated with components of the Preferred Development Plan. This includes options that might involve generation located in central and southern Manitoba. In particular, there was little assessment of the employment impacts associated with wind generation and increased Demand Side Management programs.

Manitoba Hydro indicated that Demand Side Management had not been assessed because, in part, fewer opportunities for Demand Side Management-related training and employment would exist in northern Manitoba. However, Intervener witnesses suggested that Demand Side Management create significant employment in

comparison to other capital projects. Mr. Dunsky who appeared on behalf of CAC, told the Panel in his presentation that Demand Side Management can result in two to ten times more jobs per \$ million investment.⁴⁰⁹

Mr. Klassen provided information on the job creation potential of Demand Side Management. He indicated that the cost to create a Demand Side Management job could be about \$80,000 per direct/indirect full-time equivalent (FTE) position.⁴¹⁰ The cost to create a hydropower development job could be several hundreds of thousands of dollars. In addition, Demand Side Management jobs provide ongoing employment for a wide range of skills and individuals associated with efficiency programs and trades throughout Manitoba, including northern and aboriginal communities.

In his analysis of wind power generation options, Mr. Hendriks, a witness for MMF, provided the Panel with additional information on employment benefits, especially for communities located in southern and central Manitoba. In its filing, Manitoba Hydro attributed 35 to 80 person-years to the direct construction of wind generation resources (4-8 FTEs); and a combined 120 to 240 person years, including O&M positions.⁴¹¹ Using data from British Columbia wind energy construction and operations employment, Mr. Hendriks suggested that actual employment could be significantly higher.⁴¹²

11.3.0 The Socio-Economic Impacts of the Preferred Development Plan

Manitoba Hydro estimated the economic impacts of the Preferred Development Plan that would accrue to Manitoba and the Rest-of-Canada (ROC). The Manitoba Bureau of Statistics' input-output model was used to estimate the direct, indirect and induced effects associated with project spending and the jurisdiction in which the effects accrue.

The impacts considered include a wide range of components, including the direct effects on employment and the production of goods or services delivered to Manitoba construction sites (such as cement), taxes and other indirect effects, (such as the spending on fuel and vehicle repair services associated with vehicles used on construction sites) and induced effects (where the employment income on construction sites can lead to spending on food, housing, entertainment, transportation).

For the Preferred Development Plan as a whole, which includes Keeyask, Conawapa, the North-South transmission upgrades, and the 750 MW interconnection, total

⁴⁰⁹ Exhibit CAC-62, p. 9.

⁴¹⁰ Transcript, p. 7930.

⁴¹¹ Manitoba Hydro NFAT Submission, Chapter 7, p. 39.

⁴¹² Exhibit MMF-13-1, p. 31.

expected impacts would be significant. According to Manitoba Hydro's estimates, the total economic impact of the Preferred Development Plan would be significant. For the Manitoba economy, there would be over 17,000 person-years of employment created; roughly \$1.4 billion in labour income; and just under \$1 billion on government tax revenue. The distribution of impacts between Manitoba and the rest of Canada attributable to each component of the Preferred Development Plan are provided in the following Table:⁴¹³

⁴¹³ Manitoba Hydro NFAT Submission, Appendix 2.3, p. 4.

**Table 33 Economic Impact Analysis of the Preferred Development Plan
Based on the Manitoba Bureau of Statistics Model****(\$100,000)**Manitoba - Economic Impacts of the Preferred Development Plan^{1,2}

	Keeyask		Conawapa		North-South Upgrades	750 MW Interconnection	
	Construction	O&M ³	Construction	O&M ³	Construction	Construction	O&M ³
Employment (person years)							
Project Direct	2,436	39	3,238	42	171	119	1
Other Direct	2,175	2	1,831	2	164	124	0
Indirect and Induced	3,736	29	4,234	33	251	255	1
Total Employment (person-years)	8,347	70	9,303	77	586	498	2
Labour Income	\$ 635,169	\$ 5,921	\$ 761,233	\$ 6,597	\$ 48,627	\$ 35,195	\$ 123
GDP (\$millions)	\$ 843,908	\$ 6,872	\$ 983,334	\$ 7,676	\$ 67,189	\$ 50,209	\$ 149
Tax Revenues (\$millions)							
Provincial	204,340	831	256,096	931	13,954	16,069	22
Local	40,915	162	45,807	182	2,186	2,478	5
Federal	161,059	988	195,872	1,099	12,538	10,714	23
Total Tax Revenue (\$ millions)	\$ 406,314	\$ 1,981	\$ 497,776	\$ 2,212	\$ 28,679	\$ 29,261	\$ 51

Rest of Canada - Economic Impacts of the Preferred Development Plan¹

	Keeyask		Conawapa		North-South Upgrades	750 MW Interconnection	
	Construction	O&M ³	Construction	O&M ³	Construction	Construction	O&M ³
Employment (person years)							
Project Direct	2,532	-	3,915	-	-	0	-
Other Direct	3,198	1	3,448	1	219	144	0
Indirect and Induced	10,414	16	13,601	18	386	444	1
Total Employment (person-years)	16,144	17	20,964	19	605	588	1
Labour Income	\$ 1,021,350	\$ 648	\$ 1,402,932	\$ 734	\$ 30,606	\$ 24,977	\$ 23
GDP (\$millions)	\$ 1,440,223	\$ 1,054	\$ 1,997,461	\$ 1,184	\$ 54,676	\$ 39,642	\$ 37
Tax Revenues (\$millions)							
Provincial	\$ 251,927	\$ 117	\$ 342,663	\$ 132	\$ 7,546	\$ 7,146	\$ 5
Local	\$ 66,289	\$ 31	\$ 90,164	\$ 35	\$ 1,986	\$ 1,880	\$ 1
Federal	\$ 307,444	\$ 128	\$ 426,252	\$ 144	\$ 10,935	\$ 12,437	\$ 5
Total Tax Revenue (\$ millions)	\$ 625,660	\$ 276	\$ 859,080	\$ 311	\$ 20,467	\$ 21,463	\$ 12

All of Canada - Economic Impacts of the Preferred Development Plan¹

	Keeyask		Conawapa		North-South Upgrades	750 MW Interconnection	
	Construction	O&M ³	Construction	O&M ³	Construction	Construction	O&M ³
Employment (person years)							
Project Direct	4,967	39	7,154	42	171	119	1
Other Direct	5,374	3	5,279	4	383	268	0
Indirect and Induced	14,151	45	17,834	50	637	700	1
Total Employment (person-years)	24,491	87	30,267	96	1,191	1,086	2
Labour Income	\$ 1,656,519	\$ 6,569	\$ 2,164,166	\$ 7,331	\$ 79,233	\$ 60,173	\$ 145
GDP (\$millions)	\$ 2,284,131	\$ 7,926	\$ 2,980,795	\$ 8,860	\$ 121,865	\$ 89,851	\$ 186
Tax Revenues (\$millions)							
Provincial	\$ 456,268	\$ 948	\$ 598,759	\$ 1,063	\$ 21,501	\$ 23,215	\$ 27
Local	\$ 107,204	\$ 193	\$ 135,972	\$ 217	\$ 4,172	\$ 4,358	\$ 7
Federal	\$ 468,502	\$ 1,116	\$ 622,124	\$ 1,243	\$ 23,474	\$ 23,150	\$ 29
Total Tax Revenue (\$ millions)	\$ 1,031,974	\$ 2,257	\$ 1,356,855	\$ 2,523	\$ 49,146	\$ 50,724	\$ 62

¹ 2014 dollars² Total may not add, due to rounding³ Average annual expenditures

11.3.1. Manitoba Economic Impacts

Manitoba Hydro's Preferred Development Plan and the alternative plans affect the Manitoba economy in terms of employment, needs and opportunities for new skills and training and demands for goods and services. In particular, the demand for labour has the greatest potential for economic impacts. The following Table provides the estimated Manitoba-specific economic impacts related to developing Keeyask and the 750 MW transmission line.⁴¹⁴

Table 34 Manitoba Economic Impacts of the Keeyask Project and 750 MW Transmission Interconnection

	Construction			O&M			Total Impact on Manitoba		
	Keeyask	750 MW Transmission	Total	Keeyask	750 MW Transmission	Total	Keeyask	750 MW Transmission	Total
Employment (person years)									
Project Direct	2,436	119	2,555	39	1	40	2,475	120	2,595
Other Direct	2,175	124	2,299	2	-	2	2,177	124	2,301
Indirect and Induced	3,736	255	3,991	29	1	30	3,765	256	4,021
Total Employment (person-years)	8,347	498	8,845	70	2	72	8,417	588	8,917
Labour Income	635,169	35,195	670,364	5,921	123	6,044	641,090	35,318	676,408
GDP (\$millions)	843,908	50,209	894,117	6,872	149	7,021	850,780	50,358	901,138
Tax Revenues (\$millions)									
Provincial	204,340	16,069	220,409	831	22	853	205,171	16,091	221,262
Local	40,915	2,478	43,393	162	5	167	41,077	2,483	43,560
Federal	161,059	10,714	171,773	988	23	1,011	162,047	10,737	172,784
Total Tax Revenue (\$millions)	406,314	29,261	435,575	1,981	50	2,031	408,295	21,463	437,606

One of the challenges with the economic impact analysis is to determine to what extent economic benefits accrue in Manitoba as opposed to elsewhere. If direct jobs are filled by non-Manitoba residents or if the procurement of materials is sourced outside of the province, there is a leakage of benefits to other parts of Canada or to other countries. Manitoba Hydro estimates that approximately 60% of labour income and 55% of GDP impact will be incurred in Manitoba.

TyPlan, an Independent Expert Consultant, largely confirmed the magnitude of the total economic impacts, but estimated that a greater proportion of the employment and income created would be captured within Manitoba.⁴¹⁵

In comparison, Plan 1/All Gas has the least amount of capital spending in the first part of the planning period, with only small amounts invested for thermal power plants starting in the 2020s.⁴¹⁶ Because of the smaller scale of the construction involved, the

⁴¹⁴ Manitoba Hydro NFAT Submission, Appendix 2.3, p. 4.

⁴¹⁵ Exhibit TyP-1, p. 26.

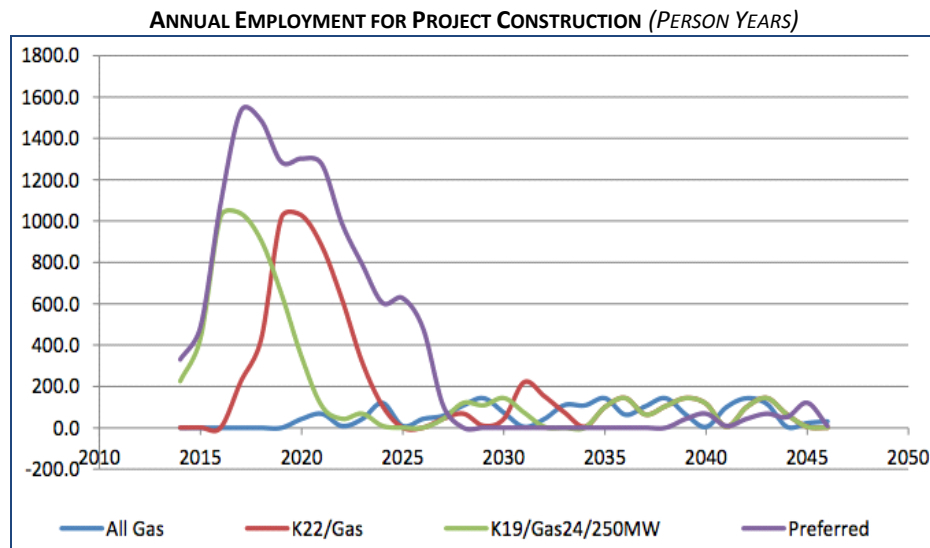
⁴¹⁶ Manitoba Hydro NFAT Submission, Chapter 13, p. 34.

economic impacts are fewer. Employment would occur in primarily southern Manitoba construction, development and operation with more ongoing operational job requirements. In contrast, plans associated with the Keeyask and Conawapa dam construction have primarily northern Manitoba impacts.

11.3.2. Employment Benefits

These differences in capital spending carry over into the demand for labour. The total annual employment directly required for the construction of the generating and transmission projects varies between different plans. As noted in the chart below, the Preferred Development Plan, again followed by the two plans that include Keeyask, is expected to generate the largest amount of construction employment.⁴¹⁷

Figure 24 Annual Employment Estimate for Project Construction



The following Table shows estimated and predicated present value of the gross wages generated by the direct employment in project construction and O&M in the preferred and alternative plans. The wages are shown separately for the employment that takes place in northern versus southern Manitoba.⁴¹⁸

⁴¹⁷ Manitoba Hydro NFAT Submission, Chapter 13, p. 35.

⁴¹⁸ Manitoba Hydro NFAT Submission, Chapter 13, p. 37.

Table 35 Anticipated Gross Wages for Construction and O&M

	Preferred Development Plan	K19/G24/250MW	K22/Gas	All Gas
Construction – N. Man.	1,317.4	599.9	503.9	--
Construction – S. Man.	142.0	95.0	72.0	62.6
Total Construction	1,459.4	694.9	575.9	62.6
O&M – N. Man.	85.0	49.6	40.5	--
O&M – S. Man.	4.2	47.4	37.3	71.5
Total O&M	89.2	97.0	77.8	71.5
Total Gross Wages	1,548.6	791.9	653.7	134.1
Difference from Preferred Development Plan	0.0	(756.7)	(894.9)	(1,414.5)

NFAT REFERENCE SCENARIO ASSUMPTIONS (2014 PRESENT VALUE IN MILLIONS 2014\$)

In terms of net benefits, Manitoba Hydro assumed that 15% of the gross wages would be paid to Manitobans. However, the net benefit for northern aboriginal employment, supported by training, recruitment and retention policies and programs is estimated to be in the order of 50% of the gross wages paid.

At the time of the NFAT Submission, Manitoba Hydro assumed that Manitobans would fill 70% of construction jobs. In February 2014, Manitoba Hydro revised this estimate downwards to 40-45%, suggesting a significant employment leakage. Of these Manitobans, 50% would be northern aboriginal people.⁴¹⁹ With respect to the southern construction jobs, Manitoba Hydro indicated that Manitobans would fill just over 50% of the gas plant related employment and almost all of the tie-line and head office related employment.⁴²⁰

The net benefits derived from the employment on Manitoba Hydro's projects are not measured by the gross wage impact, but rather by the incremental income or other benefits Manitobans would realize. The incremental wage benefits during construction and ongoing operations of various plans were estimated as follows:⁴²¹

⁴¹⁹ Manitoba Hydro NFAT Submission, Chapter 13, p. 38.

⁴²⁰ Manitoba Hydro NFAT Submission, Chapter 13, p. 40.

⁴²¹ Manitoba Hydro NFAT Submission, Chapter 13, p. 41

Table 36 Anticipated Employment Net Benefits for Project Construction and O&M

	Preferred Development Plan	K19/G24/250MW	K22/Gas	All Gas
Construction – N. Man.	234.4	113.2	95.1	0.0
Construction – S. Man.	6.1	12.7	10.6	9.0
Total Construction	240.5	125.8	105.7	9.0
O&M – N. Man.	39.2	23.6	18.9	0.0
O&M – S. Man.	.5	7.1	5.6	10.9
Total O&M	39.7	30.7	24.5	10.9
Total Net Benefits	280.2	156.5	130.2	19.8
Difference from Preferred Development Plan	0	[123.7]	[150.0]	[260.3]

NFAT REFERENCE SCENARIO ASSUMPTIONS (2014 PRESENT VALUE IN MILLIONS 2014\$)

Manitoba Hydro assumes that Manitobans will fill all Operations & Maintenance (O&M) jobs. Manitoba Hydro has also assumed that at least 45% of northern O&M jobs would be filled by northern aboriginal people based on current shares of northern operations employment and targeted measures expected with the Keeyask Project.

Manitoba Hydro estimated the net benefits of construction employment in the North would equal 12.2 to 12.4% of the total gross wages paid. The net benefits of O&M employment in the north would be 30.8% of the total gross wages paid; for O&M employment in the South net benefits would be 15% of total gross wages paid.⁴²²

11.4.0 The Keeyask Project and Northern Aboriginal Communities

11.4.1. Joint Keeyask Development Partnership

Following years of discussion and negotiation, Manitoba Hydro and four Manitoba First Nations (Tataskweyak and War Lake acting as the Cree Nation Partners, York Factory, and Fox Lake) established the Keeyask Hydropower Limited Partnership (KHLP) and negotiated the Joint Keeyask Development Agreement with Manitoba Hydro. The agreement sets out how the Keeyask Project will be developed and identifies potential income opportunities, training, employment, business opportunities, and other related matters. In addition, individual Adverse Effects Agreements were signed to identify

⁴²² Manitoba Hydro NFAT Submission, Chapter 13, p. 39.

potential negative impacts of the Keeyask Project, and outline measures to prevent or reduce these effects.⁴²³

An important feature of the Agreement is the ability of the four Keeyask Cree Nations (KCNs) to purchase equity ownership shares. The KCNs have two investment options: a common equity option, which allows the community to obtain a proportionate share of cash distributions from the Project based on the Partnership financial performance, and a preferred equity option, which involves a guaranteed return of approximately \$5 million per year.⁴²⁴ At the time of this report, the choice of option has not been made, and Manitoba Hydro advised that its partners would have until 2019 to exercise the option.⁴²⁵

In the hearings, the Panel heard differing and often passionate views about the importance of the Partnership and the construction of the Keeyask Project. Some questioned the consultations leading to the Partnership Agreement.

Members of the KCNs told the Panel that they had been actively involved in negotiations and development of the Keeyask Project. They saw many positive advantages that had come from their involvement from the beginnings of the project development, the extensive community consultations and the respect shown to their Aboriginal Traditional Knowledge. These views and advantages were summarized during Manitoba Hydro's closing submission in remarks made by the Keeyask partner First Nations.⁴²⁶

The Panel notes that the commercial arrangements between the partners are outside the scope of the NFAT Terms of Reference. Accordingly, the Panel will not comment on the merit of these submissions.

11.4.2. Employment and Training

Manitoba Hydro has assumed that northern aboriginal people will fill approximately half of the construction positions filled by Manitobans. To the end of March 2013, there already had been 1,118 aboriginal hires for the Keeyask Project, representing 61% of total hires to date.⁴²⁷ The Project will create jobs in three categories: designated trades, non-designated trades and support occupations. More specifically, Manitoba Hydro identified the following distribution of estimated employment.⁴²⁸

⁴²³ Manitoba Hydro NFAT Submission, Appendix 2.2, pp 1-4.

⁴²⁴ Transcript, p. 3581.

⁴²⁵ Transcript, p. 3797. See also PUB/MH 1-064.

⁴²⁶ Exhibit MH-209, p. 3.

⁴²⁷ Exhibit MH-143, p.1.

⁴²⁸ Exhibit MH-159, pp. 1-3 (Excerpts).

Table 37 Keeyask Project Summary of Socio-Economic Benefits for Northern Manitobans

Direct Employment	Keeyask Cree Nations	Northern Aboriginal Residents
Construction	Infrastructure: up to 110 person years; Generation: 235 to 600 person years Other: 35-40 person years	Infrastructure: up to 138 person years, including KCNs Generation: 550-1700 person years (315-1100 persons excluding KCNs)
Operations	45% of 50 estimated positions to be aboriginal Minimum 182 positions	45% of 50 estimated positions to be aboriginal

Dr. Buckland and Dr. O’Gorman provided an estimate of the income associated with the 182 ongoing operational jobs. Each job was assumed to have an annual salary of \$60,000 and inflated 2% annually. The high estimate of 182 jobs would result in total earnings of \$13.408 Million and a low estimate of 91 jobs would equate to \$7.204 Million.⁴²⁹ As was noted in the hearings, all employment is conditional on applicants having the required qualifications.

The Panel also heard about the importance of addressing the need for qualifications through adequate, long-term training and skills development programs. Several presenters noted the outcomes of the Wuskwatim Training and Employment Initiative and the Hydro Northern Training and Employment Initiative (HNTEI). The Clean Environment Commission (CEC) report on the Keeyask Project expressed its concern about HNTEI’s inability to train an aboriginal workforce of a size and skill set able to successfully compete for Manitoba Hydro jobs. The CEC recommended that the Keeyask Partnership support ongoing education and training initiatives.⁴³⁰

11.4.3. Business and Economic Impacts

The construction of the Keeyask project is estimated to bring business, investment and employment opportunities to the KCNs through the Partnership Agreement and Direct Negotiated Contract (DNC) provisions. To the end of March 2014, \$393.6 million in purchase orders have been directly negotiated with the KCNs. These include construction camp services, worksite development, access road construction, and emergency services.⁴³¹

As set out above, the KCNs also have investment options arising from the Keeyask project. The first option involves holding their investment in the form of Common Units.

⁴²⁹ Exhibit, CAC-83, p. 1.

⁴³⁰ Exhibit PUB-69, p. 104.

⁴³¹ Exhibit MH-137, p. 1.

The second option is the Preferred Unit option. The return on KCN investment for this option will be the higher of the Preferred Minimum Distribution and the Preferred Participating Distribution. In response to questions during the testimony, these estimates were updated to the following for high and low estimates of benefit.⁴³²

Table 38 Estimated Benefits to the Keeyask Cree Nations

Period	Total/Per Capita	Annual Estimated Range of Benefits	
		Low Estimate	High Estimate
Construction	Total (\$ million)	\$10.26	\$20.67
	Per capita (\$)	\$1,616	\$3,255
Post Construction @ 1.9% equity ownership/6 years post construction	Total Benefits (\$ million)	\$9.58	\$19.92
	Per capita (\$)	\$1,509	\$3,137
Post Construction @ 2.5% equity ownership/6 years post construction	Total Benefits (\$ million)	\$9.58	\$21.36
	Per capita (\$)	\$1,509	\$3,363

Under the Agreement, investment income can be used for such measures as support for the viability of resource harvesting, cultural and social development, business and employment development, construction, infrastructure, and housing.⁴³³

In addition, with this employment growth and these business opportunities, Keeyask Cree Nations members should have incomes to spend on goods and services. Construction workers will increase demand for all goods and services in the Keeyask Cree Nations. This may lead to further employment and spending, which could drive business growth.

The Panel learned that these effects would also see economic benefits for northern Manitoba communities, especially Gillam and Thompson. Other economic benefits would come from increased housing construction, local roads, or water infrastructure, especially in the Keeyask Cree Nation communities.

In closing arguments, the Panel heard of the efforts underway to create joint ventures as the communities prepare to capitalize on these economic and business opportunities. Counsel for the partners argued forcefully that these cannot be delayed or

⁴³² Exhibit CAC-85-1, p. 2.

⁴³³ Exhibit PUB-69, p.100.

postponed with the expectation that they can be easily restarted later should there be a delay in developing Keeyask.⁴³⁴

11.4.4. Impacts on Communities, Culture, and Health

It is the nature of large hydropower projects to fundamentally alter the social and economic landscape of the local region. An initial period of construction, involving employment and other economic opportunities, may be followed by decades of adverse community, cultural, social, and health consequences.

Habitat Health Impact Consulting examined the health issues faced by northern Manitoba communities. Population health outcomes in the Burntwood Regional Health Authority (where over two-thirds of the residents are aboriginal), rank poorly when compared to Manitoba averages: pre-term births are greater; life expectancy is lower; mortality is higher; the rates of asthma, arthritis, diabetes, obesity, and heart disease are all higher; injuries are more common; and mental health issues are found in greater numbers.

These problems are likely to grow given the boom-and-bust nature of the hydroelectric investment projects. The period of construction creates social, economic, and cultural stress through the rapid influx of outside workers, rising living costs, and housing pressures. After the construction ends, problems of adjustment may continue for years as incomes are lost, and traditional diets and ways-of-life have been altered. These pressures imposed on communities occur in a region with an already inadequate and challenged health care system.⁴³⁵

In its filing, Manitoba Hydro recognized the potential for a wide range of community impacts, from pressures on housing, health services, and social programs to adverse impacts on traditional hunting, trapping, and fishing ways of life. For these reasons, it has worked with the KCNs to develop plans, strategies, and programs to address public safety and worker interactions, heritage resources, traditional ways-of-life, and community health.

In its Preferred Development Plan, Manitoba Hydro has undertaken to put into place a community impact and risk mitigation strategy. Under Adverse Effect Agreements, each KCN is responsible for managing, implementing and operating adverse effects programs. The Agreements include funding and compensation measures. The Adverse Effects Agreements include offsetting programs that encompass a wide range of

⁴³⁴ Exhibit MH-204, p. 3-4.

⁴³⁵ Exhibit CAC- 47, pp. 3-4.

projects and initiatives, such as transportation to access off-system lakes and rivers to fish; cultural sustainability efforts to support learning of the Cree language and culture; an alternative justice program; funding for a crisis centre and wellness counseling program; and support for a traditional lifestyle experience, and traditional knowledge learning programs.⁴³⁶ Interveners in the NFAT hearings supported these efforts so long as there was effective monitoring and support for their implementation and success.

Several parties to the hearing were critical about benefits flowing only to the KCNs, leaving out other aboriginal groups. It was noted that the KCNs only make up 20% of northern affected aboriginal people. The Manitoba Métis Federation noted that there is no benefit sharing with the Métis.⁴³⁷ Dr. Buckland and Dr. O’Gorman urged the Panel to support efforts to extend the benefit sharing to others.⁴³⁸

11.5.0 Multiple Account Benefit-Cost Analysis

Manitoba Hydro undertook a Multiple Account Benefit Cost Analysis (MA-BCA) to determine the net benefits accruing to different stakeholders (accounts), including Manitoba Hydro, the Government of Manitoba, ratepayers, aboriginal communities and the Manitoba economy in general.⁴³⁹ In addition, the net environmental effects were considered. Where such costs and benefits could be expressed in monetary terms, the sum of each individual account provides the net benefits from a total or societal perspective.

The MA-BCA analysis was limited to a comparison of the Preferred Development Plan to three other plans: Plan 1/All Gas; Plan 2/K22/Gas; and Plan 4/K19/Gas24/250MW. It is summarized in the following Table.⁴⁴⁰

⁴³⁶ Exhibit MH-145. See also Transcript, p. 3892.

⁴³⁷ Exhibit MMF-16, pp. 4-5.

⁴³⁸ Exhibit CAC-48, p. 63.

⁴³⁹ Manitoba Hydro NFAT Submission, Chapter 13 (Updated), pp. 1-74.

⁴⁴⁰ Manitoba Hydro NFAT Submission, Chapter 13 (Updated), p. 67.

Table 39 Manitoba Hydro Multiple Account Benefit-Cost Analysis Summary

	Preferred Development Plan	K19/G24/250MW	K22/Gas	All Gas
<u>Market Valuation</u>				
Net revenues (cost) to MH and partners	--	17.0	(270.5)	(654.1)
<u>Customer Account</u>	Preferred Development Plan has highest rate increases in first 20 years (cumulatively 16 to 18 percentage points more than the alternative plans) but has lowest rate increases over long term (cumulatively by year 50 approximately 34 to 37 percentage points less than the two alternatives with Keeyask G.S. and 70 percentage points less than the all gas plan).			
Cumulative rate increase				
Reliability	Preferred Development Plan and to lesser extent the alternative with the smaller interconnection provides greater load carrying capability, lower expected loss of unserved energy and greater ability to manage extreme drought			
<u>Government</u>				
Incremental revenues net of costs/risk	--	(353.5)	(395.9)	(674.2)
<u>Manitoba Economy</u>				
Employment net benefits	--	(100.7)	(120.1)	(192.7)
<u>Environment</u>				
Manitoba GHG external cost	--	(208.6)	(174.3)	(320.3)
Global GHG impact	Preferred Development Plan and to lesser extent the two plans with Keeyask G.S. would contribute to a reduction in global emissions by displacing thermal generation in US.			
Manitoba CAC damage cost	--	(8.6)	(7.1)	(13.3)
Residual biophysical	Aquatic and terrestrial impacts with hydro projects in Preferred Development Plan and plans with Keeyask G.S.; subject to detailed environmental hearings, residual effects and local external cost expected to be relatively small with initial design, extensive mitigation, monitoring, compensation and benefit-sharing arrangements.			
<u>Social</u>	Significant net returns from up to 25% interest in Keeyask G.S. and income benefits from Conawapa G.S. in Preferred Development Plan; significant benefits from up to 25% interest in two alternatives with Keeyask G.S., greater with new sales and interconnection.			
Partner net return				
Community impacts	Wide range of potential impacts on local employment and business; population, infrastructure and service; social and community well-being; owners of land needed for rights of way and easements; major commitments and plans to minimize adverse residual effects with extensive mitigation, monitoring, compensation and partnership arrangements.			
Other Manitoba	Potentially significant bequest value from the hydro assets remaining at end of planning period; greatest with Preferred Development Plan and to a lesser extent in the alternatives with Keeyask G.S.			
Overall Monetized Net Benefit (Cost)	--	(654.4)	(967.5)	(1,854.6)

NFAT REFERENCE SCENARIO ASSUMPTIONS (2014 PRESENT VALUE IN MILLIONS OF 2014\$)

11.6.0 Government of Manitoba Benefits

Manitoba Hydro in the course of its operations pays to the Government of Manitoba fees and taxes, which currently total \$262 million annually representing 16% of Manitoba Hydro's revenues. Payments to the Province are forecast to double to \$516 million by 2032. These charges include water rental fees, payroll and capital taxes, a provincial debt guarantee fee of 1% on Manitoba Hydro's outstanding debt as well as a sinking fund administration fee. Manitoba Hydro also makes Municipal Grants in Lieu of Taxes (GILTs), which total \$22 million and are forecast to grow to \$35 million by 2032.⁴⁴¹

Morrison Park estimated the Net Present Value of future payments to the Province for different plans based on 2013 planning assumptions. The estimates were provided at a 6% discount rate, a 3% discount rate (which approximates the provincial government's own cost of borrowing), and in nominal dollars.⁴⁴²

Table 40 Morrison Park – Average Present Value of Revenue to the Province of Manitoba

Average Present Value of Revenue to the Province of Manitoba						
Reference Economics, Energy and Capital						
Reference 2013 Manitoba Load; DSM Level II						
(2015-2062)						
(\$ in millions)						
	All Gas	Plan 2	Plan 4	Plan 5	Plan 6	PDP
Revenue						
NPV @ 6.00%						
Water Rental	\$1,606	\$1,669	\$1,768	\$1,771	\$1,769	\$1,887
Capital Tax	<u>\$1,510</u>	<u>\$1,756</u>	<u>\$1,830</u>	<u>\$1,856</u>	<u>\$1,855</u>	<u>\$2,247</u>
<i>subtotal</i>	<u>\$3,116</u>	<u>\$3,425</u>	<u>\$3,599</u>	<u>\$3,627</u>	<u>\$3,623</u>	<u>\$4,133</u>
Debt Guarantee Fee	<u>\$2,370</u>	<u>\$2,692</u>	<u>\$2,838</u>	<u>\$2,918</u>	<u>\$2,908</u>	<u>\$3,486</u>
<i>Total</i>	<u>\$5,486</u>	<u>\$6,117</u>	<u>\$6,437</u>	<u>\$6,545</u>	<u>\$6,531</u>	<u>\$7,619</u>
NPV @ 3.00%						
Water Rental	\$2,628	\$2,780	\$2,928	\$2,931	\$2,928	\$3,207
Capital Tax	<u>\$2,635</u>	<u>\$3,147</u>	<u>\$3,166</u>	<u>\$3,209</u>	<u>\$3,207</u>	<u>\$4,021</u>
<i>subtotal</i>	<u>\$5,263</u>	<u>\$5,927</u>	<u>\$6,094</u>	<u>\$6,139</u>	<u>\$6,135</u>	<u>\$7,228</u>
Debt Guarantee Fee	<u>\$3,987</u>	<u>\$4,642</u>	<u>\$4,565</u>	<u>\$4,701</u>	<u>\$4,671</u>	<u>\$5,646</u>
<i>Total</i>	<u>\$9,250</u>	<u>\$10,569</u>	<u>\$10,659</u>	<u>\$10,840</u>	<u>\$10,807</u>	<u>\$12,874</u>
Nominal Dollars						
Water Rental	\$5,103	\$5,506	\$5,745	\$5,749	\$5,744	\$6,472
Capital Tax	<u>\$5,490</u>	<u>\$6,679</u>	<u>\$6,494</u>	<u>\$6,572</u>	<u>\$6,573</u>	<u>\$8,440</u>
<i>Subtotal</i>	<u>\$10,593</u>	<u>\$12,185</u>	<u>\$12,239</u>	<u>\$12,320</u>	<u>\$12,317</u>	<u>\$14,912</u>
Debt Guarantee Fee	<u>\$7,998</u>	<u>\$9,430</u>	<u>\$8,561</u>	<u>\$8,813</u>	<u>\$8,727</u>	<u>\$10,278</u>
<i>Total</i>	<u>\$18,591</u>	<u>\$21,615</u>	<u>\$20,800</u>	<u>\$21,133</u>	<u>\$21,045</u>	<u>\$25,190</u>

⁴⁴¹ PUB/MH 1-073a.

⁴⁴² Exhibit MPA-3-1, p. 38.

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

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

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

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

11.7.0 Conclusions of the Panel

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

⁴⁴³ Exhibit MPA 3-1, pp. 28-29.

⁴⁴⁴ Exhibit MPA 3-1, p. 28.

⁴⁴⁵ Exhibit MIPUG-28, p. 5. See also Transcript, pp. 7529-7530.

⁴⁴⁶ Transcript, p. 7208.

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

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

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

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

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

The Panel notes that under all scenarios, the Province of Manitoba will realize significant benefits from the development of the Keeyask Project through water rental fees and capital tax payments as further discussed in Chapter 8. The Government of Manitoba could use a portion of the incremental capital tax and water rental fees from

the development of the Keeyask Project to mitigate the impact of rate increases on lower income, northern and aboriginal communities.

12.0.0 Macro Environmental Considerations

12.1.0 Introduction

The Panel examined the risks and benefits associated with the Preferred Development Plan and its alternatives from a “macro environmental perspective.”⁴⁴⁷ While this term was not defined, the Panel assessed the Plan from a broad comparative perspective, including Greenhouse Gas (GHG) and the impact on select valued ecosystem components (VECs). Since the Panel was specifically directed not to duplicate the environmental impact assessment for Keeyask recently completed by the Clean Environment Commission (CEC), the NFAT environmental review took place at a higher level than would be expected for an environmental review. The Panel was further directed not to consider historic environmental costs.⁴⁴⁸

12.2.0 Background and Context

12.2.1. Defining the Term “Macro Environmental”

The Panel consulted with Manitoba Hydro and the Interveners, and decided on the following definition to guide its work:

“A critical analysis of the macro environmental impacts and benefits of Manitoba Hydro’s Preferred Development Plan and alternative Plans. Specifically this refers to the collective macro-economic consequences of changes to air, land, water, flora, and fauna, including the potential significance of these changes, and their equitable distribution within and between present and future generations.”⁴⁴⁹

12.2.2. The Environmental Regulatory Process

It is important to understand the overall regulatory process given that there have been two reviews of the Keeyask Project: the recently completed environmental assessment hearing by the Manitoba Clean Environment Commission (CEC) and the comprehensive study by the Canadian Environmental Assessment Agency (CEAA). The Panel expects that both of the agencies heard significantly more detailed evidence on the environmental effects of Keeyask than the Panel did, and thus defers to the findings of these agencies on several environmental issues.

⁴⁴⁷ Exhibit PUB-2, p. 3.

⁴⁴⁸ Exhibit PUB-2, pp. 7-8.

⁴⁴⁹ Exhibit PUB-10, p. 12.

Since no environmental assessment process has taken place with respect to Conawapa to date, the Panel's evidence as to the macro environmental effects of Conawapa is limited. While the greenhouse gas (GHG) implications of Conawapa were well developed in the evidence, impacts on valued environmental components (as described below) were not.

Canadian Environmental Assessment Agency Report on the Keeyask Project

The Canadian Environmental Assessment Agency completed its work and issued its report with respect to the Keeyask Project in April 2013.⁴⁵⁰ The Agency concluded the Keeyask Project is not likely to cause significant adverse environmental effects when its proposed mitigation measures were put into place.⁴⁵¹ It recommended a follow-up program should be established to verify the accuracy of the environmental assessment and to determine the effectiveness of the proposed mitigation measures. This follow-up program will focus on country foods and human health, fresh-water fish and fish habitat, water resources, birds and wildlife, wetlands, rare plants, and archaeological and heritage resources.

Manitoba Clean Environment Commission Report on the Keeyask Project

The Manitoba Clean Environment Commission has recently completed its public hearings and issued its report on the Keeyask Project.⁴⁵² After considering its evidence, the Commission recommended that the Keeyask Project be approved for a license with certain conditions.⁴⁵³ These conditions included finding specific ways of mitigating impacts on the environment, including reducing the level of disturbance or replacing habitat. Other recommendations focused on the need for additional monitoring so that adverse effects can be identified and environmental management measures developed. The Commission's report has the status of an advisory document to the provincial government. Accordingly, discretion will lie with the provincial government as to whether to incorporate these suggestions if it decides to issue an environmental permit with respect to Keeyask.

In its report, the Commission has also made several non-licensing recommendations to the Province of Manitoba, including that the Province provide guidelines for cumulative effects assessment best practices and include specific direction for proponents in

⁴⁵⁰ Exhibit PUB-70.

⁴⁵¹ Exhibit PUB- 70, pp. iii-iv.

⁴⁵² Exhibit PUB-69.

⁴⁵³ Exhibit PUB-69, pp. 165-167.

project guidelines. The Commission also noted that a regional cumulative effects assessment is currently being prepared and is expected to be released in 2015.

12.3.0 Manitoba Hydro's Environmental Assessment Approach

In lieu of providing an actual environmental impact assessment in the NFAT process, Manitoba Hydro provided a comparative overview of environmental effects through a Multiple Accounts – Benefits/Cost Analysis (MA-BCA), as well as a matrix comparison between different technologies.

12.3.1. Environment Account of Multiple Account Benefit/Cost Analysis

Manitoba Hydro evaluated its planning options using a multiple account benefit cost analysis (MA-BCA). In their filing, Manitoba Hydro addressed the consequences of the different plans through an “environment account.” This account attempted to provide a monetized social benefit of avoided greenhouse gas emissions, along with air contaminant and biophysical effects associated with the construction and operation of the projects in the different plans.⁴⁵⁴ Manitoba Hydro concluded that the Preferred Development Plan has the lowest overall social cost of GHG emissions at \$150.2 million, compared to \$470.5 million for the All Gas Plan and \$358.8 million for a plan involving Keeyask and a 250 MW interconnection.⁴⁵⁵ Manitoba Hydro did not provide a separate analysis for a plan involving only Keeyask and a 750 MW interconnection.

12.3.2. Matrix Comparison of Different Technologies

In addition to being analyzed as one of the accounts in the MA-BCA framework, Manitoba Hydro provided a matrix analysis focused on specific Valued Ecosystem Components (VECs) and compared these VECs across different technologies.⁴⁵⁶ The concept of a VEC forms part of the federal environmental assessment regime and was also applied in the environmental impact statement that formed the basis of the CEC's hearing into Keeyask.

The NFAT Panel heard evidence with respect to certain key VECs, which are described in greater detail below.

⁴⁵⁴ Manitoba Hydro NFAT Submission, Chapter 13 (Revised), p. 47.

⁴⁵⁵ Exhibit MH-185 p. 2.

⁴⁵⁶ CAC/MH 231(a).

12.4.0 Climate Change: Greenhouse Gases and Air Pollutants

12.4.1. Introduction

Manitoba Hydro's status as an exporter of hydroelectricity means that Manitoba Hydro's hydro-electric generation has GHG implications not only in Manitoba, but also in the United States. The MISO market into which Manitoba Hydro exports relies, to a large extent, on coal and gas generation, which means that exports from Manitoba have the potential to displace GHG emissions in MISO.⁴⁵⁷ Conversely, night-time imports from MISO can increase GHG emissions.

12.4.2. Assessment by Resource Option

To compare the relative GHG emissions of the Keeyask and Conawapa Projects, six comparison generation technologies were researched: supercritical pulverized coal combustion, coal with carbon capture and storage, natural gas-fired combined cycle, natural gas-fired simple cycle combustion turbines, wind and nuclear.⁴⁵⁸

Keeyask and Conawapa Project Life Cycle GHG Results

Over a 100-year life, the Keeyask Project is estimated to produce approximately 980,000 tonnes of CO₂ equivalent. Of this amount, GHG emissions associated with the construction phase of the project account for approximately 46% of life-cycle GHG emissions.⁴⁵⁹ The Conawapa Project is estimated to produce approximately 900,000 tonnes of CO₂ equivalent with 86% of that amount related to construction.⁴⁶⁰

Comparison with Other Power Generation Technologies

As shown in the Figure below, lifetime GHG emissions for the two proposed hydro projects are significantly lower than for alternative technologies:⁴⁶¹

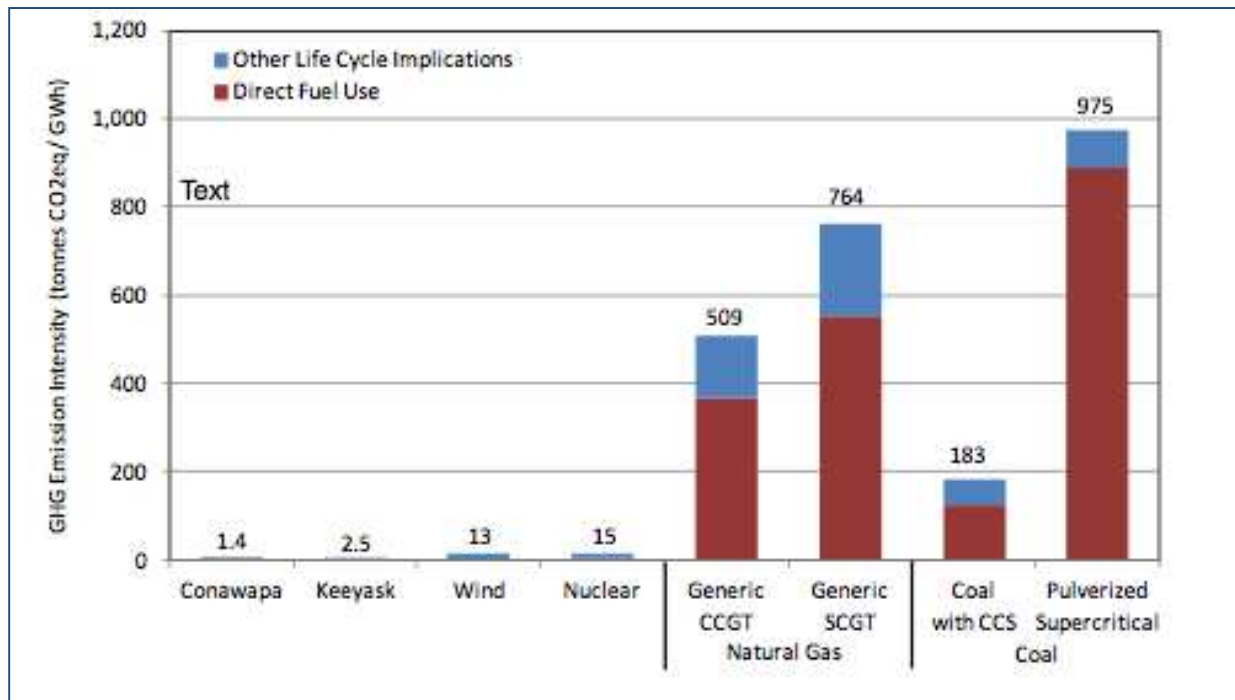
⁴⁵⁷ Manitoba Hydro NFAT Submission, Chapter 13 (Revised), p. 67.

⁴⁵⁸ Manitoba Hydro NFAT Submission, Chapter 13 (Revised), p. 4.

⁴⁵⁹ Manitoba Hydro NFAT Submission, Appendix 7.3, pp. 7-8.

⁴⁶⁰ Manitoba Hydro NFAT Submission, Appendix 7.3, p. 9.

⁴⁶¹ Manitoba Hydro NFAT Submission, Appendix 7.3, p.12.

Figure 25 Comparison of Life Cycle Greenhouse Gas Emissions for Different Sources of Electricity

This is further borne out by an examination of the intensity-based GHG emissions for different technologies. The All Gas Plan would create 28.4 tonnes of CO₂e/GWh, compared to 13.1 tonnes of CO₂ equivalent/GWh for the Keeyask/Gas/750 plan and 5.5 tonnes of CO₂e/GWh for the Preferred Development Plan.⁴⁶² In terms of generating technologies, only wind and nuclear technology are competitive with hydroelectricity.

Unfortunately, no separate GHG emissions analysis was provided for Demand Side Management (DSM). However, it stands to reason that avoided generation would be at least as favourable as hydroelectric generation.

Greenhouse Gas Displacement

The energy produced by Keeyask and Conawapa Projects (less transmission losses) will displace a variety of fossil-fuelled generation in the interconnected U.S. export markets. Manitoba Hydro's analysis of the electricity market estimates the avoided GHG emissions due to energy being injected into the regional energy markets from Manitoba. Conventional coal generation is typically in the order of 900 to 1,100 tonnes CO₂e/GWh, while natural gas can range from about 300 to 800 tonnes CO₂e/GWh.

⁴⁶² Exhibit MH-148, p. 2.

depending on the specific technology and its efficiency.⁴⁶³ Combined-cycle gas turbines (CCGT) tend to be significantly more efficient than simple cycle gas turbines (SCGT).⁴⁶⁴

Manitoba Hydro currently assumes that its net exports displace 750 tonnes CO₂ equivalent/GWh.⁴⁶⁵ This reflects a marginal generation mix of various fossil fuels and technologies. Given that the current marginal generation, other than in peak periods, remains primarily coal; the 750 tonnes of CO₂ equivalent/GWh factor used by Manitoba Hydro is considered to underestimate the emissions displaced by exports. The net positive effect of the Keeyask and Conawapa Projects on climate change reflects the small life cycle GHG emissions of the proposed projects versus the much more significant emission reductions that will result from the displacement of high GHG intensity sources of generation.⁴⁶⁶ MNP determined the following displacement potential:⁴⁶⁷

Table 41 Cumulative Greenhouse Gas Emissions and Cumulative Greenhouse Gas Displacement Potential of Alternative Development Plans

Selected Plans' Air Impacts



Air Impacts*	Preferred Plan #14: K19/C25/ 750MW (WPS Sale & Investment)	Plan #1: All Gas	Plan #4: K19/Gas24/ 250MW	Plan #5: K19/Gas25/ 750MW (WPS Sale & Investment)	Plan #7: SGCT/C26
Cumulative GHG Operating Emissions	7.5 Mt CO ₂ e	33.2 Mt CO ₂ e	25.4 Mt CO ₂ e	16.3 Mt CO ₂ e	13.0 Mt CO ₂ e
Cumulative Regional GHG Displacement Potential	191.6 Mt CO ₂ e	22.5 Mt CO ₂ e	107.7 Mt CO ₂ e	94.4 Mt CO ₂ e	102.1 Mt CO ₂ e

*All values were taken from MH NFAT filing, Appendix 9.1 – High Level Development Plan Comparison Table

Page 14

⁴⁶³ Manitoba Hydro NFAT Submission, Appendix 7.3, p. 12.

⁴⁶⁴ Manitoba Hydro NFAT Submission, Appendix 7.2, p. 6.

⁴⁶⁵ Manitoba Hydro NFAT Submission, Appendix 7.2, p. 12.

⁴⁶⁶ Manitoba Hydro NFAT Submission, Appendix 7.3, pp. 12-13.

⁴⁶⁷ Exhibit MNP-8, p. 14.

12.5.0 Comparing Environmental Effects for Competing Technologies

12.5.1. Introduction

As part of its review, the Panel received evidence regarding the high-level impacts to be expected from different technologies. These are summarized in this section.

12.5.2. Hydropower Generation

While large hydropower projects can have significant global GHG benefits, they can also have a profound environmental impact on the land and water. Localized impacts include flooding, shoreline erosion and water quality impacts. In the context of a heavily developed river system like the Lower Nelson, the cumulative impacts must be considered together with the incremental impacts of a new dam.

Keeyask Project

The Keeyask Project will require about 125 km² of land in the boreal forest, of which 50 km² will be land that is flooded for the reservoir and dam.⁴⁶⁸ This ecosystem and its water regime have already been altered considerably by previous hydroelectric developments and are therefore vulnerable to further change.⁴⁶⁹

According to Manitoba Hydro's NFAT Submission, the water regime changes include flooding and increased water levels at Keeyask downstream of Lake Winnipeg on the Upper Nelson River. The reservoir will stretch from the generating station approximately 93 km² in area and it will extend 42 km upstream to the outlet of Clark Lake. The reservoir will consist of approximately 48 km² of existing waterways, 45 km² of newly submerged lands and 264 km of shoreline.⁴⁷⁰ Water quality in the newly flooded areas will be affected during the initial 10 to 15 years, but impacts are expected to diminish thereafter.⁴⁷¹

In their report, MNP noted the following impacts: complete loss of Gull Rapids; slower, deeper water through Gull Lake, Birthday Rapids, and as far upstream as the outlet of Clark Lake; changes in erosion patterns and water quality downstream of Keeyask, but not upstream in Split Lake; and flooding of several Caribou calving islands in Gull Lake.⁴⁷²

⁴⁶⁸ CAC/MH I-231(a), p. 8.

⁴⁶⁹ Exhibit MNP-6, p. 37.

⁴⁷⁰ Exhibit MNP-6, p. 37.

⁴⁷¹ CAC/MH I-232(a), p. 10.

⁴⁷² Exhibit MNP-6, pp. 39-40.

Conawapa Project

Preliminary information exists on the water impacts associated with the Conawapa Project. It will require over 20 km² of land, of which 10 km² is needed for construction and only 5 km² will be flooded for reservoir requirements.⁴⁷³ Since no environmental impact statement has been prepared for Conawapa to date, the environmental impacts of Conawapa are significantly less well known than those of Keeyask. Similarly, any potential changes to the overall water flow regime and regulation of Lake Winnipeg to maximize exports have not been examined in detail.

Hydropower Mitigation Strategies

Manitoba Hydro plans to mitigate, manage and monitor environmental effects, primarily for the Keeyask Project. This includes environmental protection, management and monitoring plans. The program will cover erosion control from the shoreline, roads, stream crossings, earth dams and dykes, and will guide compliance with relevant legislation.⁴⁷⁴

In their review, MNP advised the Panel that these measures are “commensurate with expectations of a project this size. There is always risk that mitigation features are not as effective as expected, but we do not believe that Manitoba Hydro is missing any important elements in their mitigation strategies.”⁴⁷⁵ MNP’s report was filed prior to the CEC releasing its report.

12.5.3. Natural Gas Thermal Generation

While GHG emissions from gas-fired power plants are less than emissions from coal-fired power plants, they are still significant, and the CEC noted that a comparably sized natural gas plant would produce as much greenhouse gas in 177 days as the Keeyask Generation Project will produce in 100 years.⁴⁷⁶ Concerns over the impact of hydraulic fracturing and the considerable risks it poses to potable water supplies and human health as well as its significant contribution to global warming, must also be considered.⁴⁷⁷

⁴⁷³ CAC/MH I-232(a), p. 8.

⁴⁷⁴ Exhibit MNP-6, p. 45.

⁴⁷⁵ Exhibit MNP-6, p. 47.

⁴⁷⁶ Exhibit PUB-69, p. 61.

⁴⁷⁷ Exhibit CAC-29, p.22.

12.5.4. Wind Power

According to CAC's expert witness Dr. Gunn, much of the research on the environmental impacts of wind energy production has focused on the potential adverse effects of multiple rotor blades on birds and landscapes. Other studies suggest that no serious unusual interference with wildlife is associated with wind energy development. Aside from those associated with equipment production, wind energy CO₂ emissions are extremely low. Human health impacts include visual disturbance and shadow flicker.⁴⁷⁸

12.5.5. Solar Photovoltaic Power

There are two types of solar photovoltaic generation technologies – roof-based and ground-based. While GHG-emissions are created upon production, emissions are extremely low during the operating phase. However, while roof-based systems require little landmass, ground-based solar farms can have significant land requirements.⁴⁷⁹

12.5.6. Demand Side Management

Reducing energy consumption has obvious environment benefits, relative to new generation construction and development. The concept of Demand Side Management is not new and has been applied for decades not only to energy supplies but also to other public utilities such as water and gas. By reducing the need for new generation, Demand Side Management has the potential to avoid the adverse effects of other technologies. However, the environmental impact of DSM is dependent on the specific measure used.⁴⁸⁰

12.6.0 Valued Ecosystem Components (VECs)

12.6.1. Introduction and Scope

The Canadian Environmental Assessment Agency defines Valued Ecosystem Components (VECs) as environmental elements of the ecosystem that are identified as having unique, scientific, social, cultural economic and aesthetic importance. In the environmental impact statement filed before the CEC, a total of 38 VECs were discussed.⁴⁸¹

Aside from GHGs, which are discussed above, the analysis before the NFAT Panel focused on three key VECs, namely lake sturgeon, caribou, and public health and

⁴⁷⁸ Exhibit CAC-29, pp. 26-27.

⁴⁷⁹ Exhibit CAC-29, pp.31-32.

⁴⁸⁰ Exhibit CAC-29, pp. 34-36.

⁴⁸¹ Exhibit PUB-69, p. xv.

community safety. The Panel notes that virtually all of the evidence it heard with respect to specific VECs related to the Keeyask Project, with little information being provided as to the environmental effects of the Conawapa Project, other than high-level evidence with respect to GHG and flooding impacts.

12.6.2. Lake Sturgeon

Lake sturgeon are a culturally and spiritually important species to the Cree. Lake sturgeon are a Manitoba heritage species and have been designed as endangered by the Committee on the Status of Endangered Wildlife in Canada (COSEWIC).⁴⁸² The federal government is also currently considering whether to list lake sturgeon as an endangered species under the *Species at Risk Act* (SARA).⁴⁸³ In addition, lake sturgeon are particularly vulnerable due to a number of unique characteristics: they have a late sexual maturity, infrequent spawning patterns, slow to maturity growth rates, and 60-year plus longevity.⁴⁸⁴ Manitoba Hydro identified lake sturgeon as the number one regulatory risk with respect to the Keeyask Project.⁴⁸⁵

In its filing, Manitoba Hydro notes that the Keeyask Project will affect sturgeon spawning habitat. In assessing the potential impacts, MNP determined that a number of the anticipated impacts have the potential for significant, adverse effects. Construction will impede fish migration and affect spawning. Sturgeon require a large turbulent rapids habitat. Construction will result in the permanent loss of Gull Rapids. Fish movement will be altered as a result of the presence of the generating station and increased access might encourage more fishing and overharvesting.⁴⁸⁶

To mitigate these effects, Manitoba Hydro indicated that the Keeyask Partnership will develop new sturgeon habitat; undertake an experimental, up-stream fish passage study; install turbines that enable a large percentage of fish to successfully pass downstream; and implement a regional sturgeon stocking program.⁴⁸⁷ The Panel heard concerns that stocking programs have not been proven effective at hydroelectric projects; habitat required to fulfill life cycles may not be available; and large sturgeon may not be able to move past the generating station.⁴⁸⁸

MNP examined plans to install a temporary, experimental catch and transport system and conduct studies of fish habitat and behavior. While they concluded that this was a

⁴⁸² Transcript, p. 3870.

⁴⁸³ Manitoba Hydro NFAT Submission, Chapter 13 (Revised), p. 54.

⁴⁸⁴ Exhibit MNP-6, p. 56.

⁴⁸⁵ Transcript, p. 3869.

⁴⁸⁶ Exhibit MNP-6, pp. 56-57.

⁴⁸⁷ CAC/MH I-231(a), p. 13.

⁴⁸⁸ CAC/MH I-231(a), p. 14.

“sensible approach,” there is equally the cost to build and operate it.⁴⁸⁹ Other testimony and the findings of the Clean Environment Commission questioned this approach. The CEC and CEAA environmental reports into the Keeyask Project both concluded that a permanent fish passage was not necessary. The Panel notes that, the Clean Environment Commission expressed its concerns about the mitigation strategies, and recommended that the Keeyask Partnership stock lake sturgeon for at least 50 years.⁴⁹⁰

The Panel notes that there remains a risk to lake sturgeon, and that the CEC recommendations will impose ongoing operational costs if imposed, as a term of Manitoba Hydro's environmental licence for Keeyask.

12.6.3. Caribou

Caribou are important to the northern ecology and to northern aboriginal people. Boreal woodland caribou are protected under the federal *Species at Risk Act (SARA)* and *The Endangered Species Act (Manitoba)*. Some local Cree identify woodland caribou in the Keeyask region, but federal and provincial regulators have not determined that the caribou resident in the area are protected boreal woodland caribou.⁴⁹¹

In their filing, Manitoba Hydro has identified a number of potential impacts on caribou. They include the habitat losses and fragmentation, increased predator access, and sensory disturbances from heavy machinery and construction activities. Among strategies identified to mitigate these potential effects, Manitoba Hydro and Keeyask Partnership have listed adjusted roads, borrow areas and excavated placement areas to avoid sensitive caribou habitat; limits of some construction activities such as blasting to the extent practicable during the calving season; and blocking access trails once they are no longer required (i.e., post-construction). New calving habitat is also expected to be created on new islands in the new reservoir.⁴⁹²

In their analysis, MNP determined that these impacts had a medium to low consequence: construction will not lead to a reduction of food sources; increased predator and hunters' access will be a concern; there will be minimal loss of habitat for calving; and caribou are shown not to abandon habitat.⁴⁹³

In their report, the Clean Environment Commission came to the conclusion that additional research was required given insufficient data on woodland caribou

⁴⁸⁹ Exhibit MNP-6, p. 64.

⁴⁹⁰ Exhibit PUB-69, p. 78.

⁴⁹¹ CAC/MH I-231(a), p. 14.

⁴⁹² CAC/MH I-231(a), pp. 13-15.

⁴⁹³ Exhibit MNP-6, pp. 49-50.

populations and recommended that a three- to five-year telemetry study be put into place.⁴⁹⁴

12.6.4. Mercury

Methyl mercury exposure and contamination of fish can be caused by mineral bank erosion and peat land disintegration.⁴⁹⁵ Since mercury bio-accumulates in fish, this can cause a health risk from eating fish caught in the Nelson River. Predictions are that the maximum mean mercury concentrations for lake whitefish, northern pike, and walleye from the Keeyask reservoir and Stephens Lake could be reached within three to seven years post-construction, and return to pre-project levels at least 30 years post-impoundment.⁴⁹⁶

In its report, the Clean Environment Commission noted that this is an understandable concern, but concluded that methyl mercury would be a temporary effect that would occur over two to three decades. The Commission recommended continued monitoring.⁴⁹⁷

12.7.0 Adverse Effects Agreements

To compensate for any residual effects not addressed through mitigation, Manitoba Hydro negotiated adverse effects agreements with each of the Keeyask Cree Nations. Pursuant to these agreements, Manitoba Hydro provides a series of “offsetting programs” in each of the communities, as well as a residual monetary payment. The offsetting programs are primarily cultural in nature, such as the provision of gathering centres and counselling programs, but also include a healthy food fish program in each community, which facilitates access to fish not affected by increased mercury levels in the Nelson River.⁴⁹⁸ The residual monetary payments provide ongoing payments for the duration of the Keeyask project in the case of three of the communities, and payments until 2025 for the fourth.⁴⁹⁹

12.8.0 Need for Regional Cumulative Environmental Assessment

In the course of conducting the NFAT Review, the Panel heard from several affected communities who commented on the effect of past hydroelectric developments on their lives. In addition, Dr. Gunn, who appeared on behalf of CAC, testified that a macro

⁴⁹⁴ Exhibit PUB-69, p. 96.

⁴⁹⁵ Exhibit MNP-6, p. 69.

⁴⁹⁶ Exhibit MNP 6, pp. 69-70.

⁴⁹⁷ Exhibit PUB-69, pp. 112-113.

⁴⁹⁸ Exhibit MH-145.

⁴⁹⁹ Exhibit PUB-58-5, Tab 9.

environmental review should be cumulative in nature. This means that it should consider not merely the incremental effect of one project, but the collective effect of the project when added to impacts that have already happened.⁵⁰⁰

The Panel notes that the CEC recommended a regional cumulative effects assessment for the area in its report into the Bipole III project, and commented in its report on the Keeyask Project that it expected such an assessment to be available by 2015, yet did not recommend withholding a licence for the Keeyask Project pending the availability of the document. The NFAT Panel supports the preparation of a regional Cumulative Effects Assessment and is heartened by the fact that on May 27, 2014, the Province and Manitoba Hydro agreed to Terms of Reference for a regional Cumulative Effects Assessment of hydro-electric developments that includes the Nelson, Burntwood, and Churchill River systems.

12.9.0 Conclusions of the Panel

In the Panel's view, all plans presented by Manitoba Hydro will have an impact on the local, regional and global environment. To some extent, such effects can be avoided through a focus on demand reduction through DSM efforts that avoid the need for new generation sources being constructed. However, if one accepts that new generation will be required in Manitoba within the next decade, DSM does not represent a freestanding solution.

Hydroelectricity emits minimal greenhouse gases and does not rely on fossil fuels. While wind and solar power are environmentally friendly technologies with similarly low GHG emissions, they are intermittent power sources that do not provide capacity and as such must be backed by either hydroelectricity or gas-fired generation.

These alternative generation options should be analyzed further as part of any future integrated resource plan, to assess their economics and study how they could be integrated into Manitoba Hydro's system. Manitoba Hydro expended substantial efforts to mitigate adverse environmental effects from Keeyask. The Panel received little substantive evidence on efforts to mitigate the impact of Conawapa, which has yet to be subject to environmental proceedings.

Overall, the Panel is of the view that while a plan involving Keeyask is environmentally favourable from an avoided GHG emissions basis, Keeyask creates an ongoing risk to lake sturgeon and will have a significant effect on its sustainability on the Nelson River. Nonetheless, the effects have been mitigated to the extent possible and have been

⁵⁰⁰ Exhibit CAC-29, p. 12.

found to be acceptable by the Clean Environment Commission and the most affected First Nations.

To that extent, the Panel concurs with the Clean Environment Commission that a regional cumulative effects assessment for the area is required to determine the cumulative effects of hydroelectric developments to date. To date, insufficient information has been collected and better assessment methods are needed.

In addition, the Panel support the actions now needed as a result of the Clean Environment Commission recommendations. In particular, it notes the importance of the CEC's findings with regard to caribou and lake sturgeon.

13.0.0 The Commercial Perspective

13.1.0 Introduction

The Preferred Development Plan and suggested alternative development plans bring together all of the costs, risks and benefits that affect stakeholders such as ratepayers, the Government of Manitoba, Manitoba taxpayers, First Nations commercial partners and others. The Panel considered Manitoba Hydro's Plans from a number of perspectives, including financial, socio-economic and environmental. It assessed the costs of construction and the realities of expenditures and anticipated revenues.

In this chapter, the Panel considers the Preferred Development Plan and the alternatives from a commercial perspective. The Panel treats the Plan and alternatives as investments, and ratepayers as shareholders. In fact and as Morrison Park told the Panel, Manitoba ratepayers are in a disadvantaged position. They have no certainty in advance. They cannot choose another supplier of electricity, and they must shoulder the risk burden.⁵⁰¹

13.2.0 The “Positional View”

In their analysis of Manitoba Hydro's plans, Morrison Park briefed the Panel on the realities of its “positional view.” In many regards, the Panel and the NFAT Review was caught between decisions and actions already taken and the uncertainty of a long-term planning horizon. Uncertainties underlay many of the projections and forecasts, and they extend out not only years, but also many decades.

In this regard, the analytical tools and planning methods can be a limiting factor. The search for precision can disguise the reality that such tools are often based on assumptions that fail to consider future possibilities. In this context, the Panel was persuaded by the guidance provided by Morrison Park when they stated:

There is a significant danger in assuming that a view of the future from the perspective of today will be very accurate. All such assumptions should be approached with humility, and treated with respect as the best available basis for decision-making, but without claiming them to be more than what they are. Decisions cannot be made without taking a view of the future, but the future may prove unwilling to agree with the forecasts made of it.

⁵⁰¹ Exhibit MPA-3, p. 69.

It is commonplace that commercial transactions are analyzed using mathematical models, often providing a degree of precision measured in decimal points, which sometimes gives the illusion of accuracy or predictive power. . . . However, these models are only as accurate as the assumptions about the future that underlie them. Since those assumptions must be given a broad range because of the difficulty inherent in predicting the future, especially over decades, the models should and do result in outputs with an equally broad range. This means that mathematical models sometimes may be capable of excluding certain decision options from the realm of reasonable commercial choice, but cannot always point to a single preferred outcome among several. In these cases, decisions still must be made, but they must be rendered on the basis of judgement. Commercial decisions are ultimately about judgement, and judgement is extremely difficult to quantify.⁵⁰²

Useful forecasts are typically based on assuming incremental changes to the practices of the past. Over extended time horizons, the practices and assumptions of the past have less value as a forecasting tool. Incremental change can be pushed aside by transformative events. As Morrison Park stated, “*what may appear to be reasonable today may at some point in the future – with the benefit of hindsight – look like a terrible mistake, or a massive stroke of luck.*”⁵⁰³

The NFAT Panel had to consider this positional view. The NFAT Review took place in the midst of actions already taken, immediate decisions to be taken, and long-term uncertainties. Manitoba Hydro chose which plans to present and analyze, without input from the NFAT Panel or Interveners. Significant costs associated with Keeyask have been expended, and export contracts signed.

Commercial decisions, especially long-term decisions, are ultimately about judgment. As this report has already indicated, the economic and financial analyses have been useful tools to determine whether the Preferred Development Plan is in the best interests of Manitoba, and superior to others. However, the Panel is called on to consider a wide range of factors, including socio-economic and environmental factors, risks associated with droughts, and ratepayer risks. In the final analysis, the Panel has been asked to consider all the evidence and use its judgement to balance risk and opportunity, cost and benefit.

⁵⁰² Exhibit MPA-3, p. 16.

⁵⁰³ Exhibit MPA-3, p. 16.

13.3.0 The Situation Today

Analyzing the reasonableness of Manitoba Hydro's Preferred Development Plan and alternatives from a commercial perspective involves looking at the options from the position that one is in today. Because of the circumstances and the timing of the NFAT Review, the Panel was not provided with a blank canvas.

The information before the Panel with respect to the Keeyask Project and the 750 MW transmission interconnection provides evidence of a tangible set of initiatives. The following bullets describe key aspects of the current commercial realities the Panel weighed in coming to its conclusions:

- Approximately \$1.4 billion will have been spent on Keeyask by end of June 2014. If the project proceeds, these expenditures will be part of the project costs to be recovered when in-service. If the project does not proceed, these sunk costs will have to be absorbed into rates and paid by ratepayers over a much shorter period.
- Manitoba Hydro has signed the general civil contract for the Keeyask Project and authorized the general civil contractor to commence marshalling resources. Manitoba Hydro wishes to begin construction of the Keeyask project during summer 2014 in order for the first of the generating turbines to be in service in 2019.
- The Manitoba Clean Environment Commission has recommended that an environmental licence be issued for Keeyask.
- The federal environmental licensing process for the Keeyask Project is complete.
- Bipole III will be available to transmit Keeyask's power to the south.
- New export contracts have been negotiated and signed with counterparties in the United States to purchase hydro-electric power. Part of the output of Keeyask has been sold under firm export contracts. Manitoba Hydro continues to actively market Keeyask power to potential extra-provincial customers.
- A 750 MW transmission interconnection between Manitoba and Minnesota is being pursued for a projected in-service date of 2020. Minnesota Power has a 51% ownership stake in and is championing the interconnection before the Minnesota Public Utilities Commission.
- Manitoba Hydro will own the Manitoba portion of the interconnection and is taking a 49% ownership stake in the U.S. portion. Manitoba Hydro has agreed to pay 67% of the costs of the construction and operations of the new line. Manitoba

Hydro told the Panel it is seeking to divest its ownership position in the U.S. intertie and is actively negotiating to do so.

- The 750 MW transmission interconnection will enable Manitoba Hydro to deliver power under export agreements with Minnesota Power and Wisconsin Public Service, and may open up new market opportunities to sell Keeyask energy to other potential customers.
- Four First Nations communities have partnered with Manitoba Hydro to develop the Keeyask generation project. Agreements detailing the commercial arrangements among the parties have been negotiated and signed.

With respect to the Conawapa Project, Manitoba Hydro has spent \$400 million to date, and wishes to spend an additional \$323 million to preserve its in-service date.⁵⁰⁴ However, despite the sunk costs, Manitoba Hydro has not made a viable business case for the Conawapa Project:

- Manitoba Hydro's own projections for DSM savings set out in the 2014 15-year Power Smart Plan supplant more than 85% of the net capacity addition that Conawapa was to provide by its in-service date.
- The Conawapa Project has yet to proceed to final design.
- No environmental assessment hearings have taken place to date.
- One export contract with Wisconsin Public Service is considered to be conditional upon Conawapa being in service by 2031. If Conawapa does not proceed, the contract would have to be amended to remove that condition. There are no guarantees such amendment negotiations would be successful, without Conawapa. Manitoba Hydro has the capacity to fulfill the power requirements called for in the contract from existing system resources, including Keeyask.
- Unless firm export contracts are negotiated for Conawapa's power, the output would have to be sold at the market prices of the day.

13.4.0 The Parameters of the Commercial Perspective

Morrison Park was of the view given that Keeyask and the 750 MW transmission interconnection are "immediate, real and actionable projects"⁵⁰⁵ there would have to be a very persuasive case to terminate, change course, or choose another alternative.

Mr. Pelino Colaiacovo from Morrison Park put it this way:

⁵⁰⁴ PUB/MH-1-238(c).

⁵⁰⁵ Exhibit MPA 3-1, p. 43.

... our point was that given all of the money that's been spent on Keeyask, given the commercial arrangements that have been made for Keeyask, a decision to not proceed ... could only occur if there was very, very strong evidence that not proceeding would be advantageous to the ratepayer and to other stakeholders. That it's not sufficient to say that financial modeling, or economic modeling suggests that All Gas is preferable to -- to going ahead with Keeyask on some narrow basis.

That the burden of proof, frankly, lies on people who question the decision to go forward with Keeyask, to demonstrate that other options are conclusively better. If they can't demonstrate that ... their other options are conclusively better, then Keeyask is the real option that -- that is before the Government of Manitoba, is before the NFAT process. There has been some new information. The cost of Keeyask has gone up. It's legitimate to recalculate numbers to ensure that ... new information doesn't change all of the analysis that's happened so far to date.⁵⁰⁶

The view with respect to Conawapa was quite different. Morrison Park described Conawapa as a “development opportunity”, competing with other potentially superior alternatives; hence continued expenditures to develop Conawapa should have to be justified from that perspective.⁵⁰⁷

13.5.0 Conclusions of the Panel

It is clear to the Panel that from a commercial perspective much more is at stake with Keeyask and the 750 MW transmission line than there is with Conawapa. Cancelling the Keeyask Project now would result in material consequences for ratepayers, because Manitoba Hydro would have to recover the \$1.4 billion spent on the Project to date. The arrangements with First Nations would have to be terminated and significant economic opportunities lost. Manitoba Hydro's commercial reputation may suffer. The Keeyask general civil contract would have to be renegotiated and cancellation fees may be payable.

Even changing the timing of the Keeyask development could present challenges and commercial consequences. Agreements and understandings either embedded or underlying export contracts would be affected. This could lead to future negotiation consequences. Commercial reputation concerns, reliability benefits and the possibility of future export opportunities are all tied to the 750 MW transmission interconnection.

⁵⁰⁶ Transcript, p. 7614.

⁵⁰⁷ Exhibit MPA-4, p. 6.

The Panel finds persuasive Morrison Park's arguments with respect to the high burden required to demonstrate other alternatives as being preferable to Keeyask and the 750 MW transmission interconnection. Keeyask and the 750 MW transmission line represent a tangible commercial opportunity. Therefore, it would be prudent to proceed with the development of Keeyask and the 750 MW transmission line.

The Panel concurs with Morrison Park's view that Conawapa is simply a development opportunity. It was therefore incumbent on Manitoba Hydro to justify why Conawapa is superior to other alternatives, either those that might exist now or be present in the future. Manitoba Hydro has not established that justification.

Conawapa's economic benefits have not been demonstrated. The risks to and burden on ratepayers are too high. Nor has Manitoba Hydro put forward a business case that supports protecting Conawapa's 2026 in-service date. Should the need for new generation resources of the magnitude of Conawapa arise in the future, consideration of Conawapa as a generating option must be justified through a full and thorough integrated resource planning process. Continuing to spend money on Conawapa would unduly advantage Conawapa in any future analysis and disadvantage other contending alternatives. The Panel strongly believes that, within a proper integrated resource planning process, there must be a level playing field with respect to the consideration of future alternatives.

14.0.0 Recommendations

In accordance with the Terms of Reference and based on the evidence presented by Manitoba Hydro, Interveners and the Independent Expert Consultants, the Panel makes the following recommendations.

Manitoba Hydro's Preferred Development Plan

The Panel was requested to assess whether the needs for Manitoba Hydro's Preferred Development Plan are thoroughly justified and sound, its timing is warranted and the factors that Manitoba Hydro relied on to prove its needs are complete, reasonable and accurate. The Terms of Reference also asked the Panel to assess whether the Preferred Development Plan is justified as superior to potential alternatives and is in the best long-term interest of the province of Manitoba. The factors that the Panel considered in reaching its conclusions and recommendations were defined by the Terms of Reference and have been discussed throughout this Report.

The Panel concludes that new generation resources will likely be required no later than 2024. However, Manitoba Hydro has not established that the Preferred Development Plan is the best alternative to meet this need, or has been justified as being in the best long-term interest of the province of Manitoba.

- 1. The Panel recommends that the Government of Manitoba not approve Manitoba Hydro's proposed Preferred Development Plan.***

However, the Panel recommends alternative actions that are better justified in terms of meeting the need for new resources and export opportunities, while addressing the risks to ratepayers and the requirement for a new approach in planning future generation resources. These actions are presented in the recommendations below.

Keeyask Project

The Panel concludes that the Keeyask Project is justified in terms of resource needs for domestic and export requirements. The Panel considered the impending domestic load requirements, and determined that even with the successful implementation of Demand Side Management programs, Manitoba requires new, long-term energy supply based on the hydropower from the Keeyask Project. The Panel was persuaded by the commercial realities of the Keeyask Project, including some \$1.2 billion already spent on the Project, as well as the supporting export contracts and the socio-economic benefits from partnership agreements with First Nations.

The Panel considered the question of the in-service date and, in light of the potential impacts of Demand Side Management initiatives, whether to recommend deferral of the start of Keeyask's construction. The Panel notes the need for new capacity as a result of load demands associated with expected new pipeline construction. Agreements also have been signed with the Keeyask Cree Nations that could be adversely affected by delay. As a result, the Panel found no convincing reason to delay the in-service date of 2019 for the Keeyask Project.

- 2. The Panel recommends that the Government of Manitoba authorize Manitoba Hydro to proceed with the construction of the Keeyask Project to achieve a 2019 in-service date.***

750 MW Transmission Interconnection Project

Manitoba Hydro has demonstrated the value of constructing the proposed 750 MW Transmission Interconnection to the United States. Financial and economic analysis indicates that this Transmission Interconnection adds value to Manitoba Hydro's future plans. The Transmission Interconnection is equally justified in terms of its contribution to system reliability, and to address export and import needs during periods of drought or system emergencies.

- 3. The Panel recommends that the Government of Manitoba authorize Manitoba Hydro to proceed with the 750 MW U.S. Transmission Interconnection Project for a 2020 in-service date.***

Conawapa Project

The Panel concludes that Manitoba Hydro has not justified the construction of the Conawapa Project as part of the Preferred Development Plan, or any future plan. In light of the Panel's recommendations on Keeyask, the 750 MW Transmission Interconnection and expected impacts of future Demand Side Management efforts, Conawapa is not needed for either domestic or export needs. It makes no positive contribution to the financial value of the Preferred Development Plan or any alternative resource plans.

- 4. The Panel recommends that the Government of Manitoba not approve the construction of the Conawapa Project and the North-South Transmission Upgrade Project.***

Given the Panel's view that the Conawapa Project has no place in future plans or strategies, there is no need to continue any activity to protect a future in-service date. Nor should existing sunk costs become a future justification for Conawapa.

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

Demand Side Management Plans and Programs

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

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

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

6. ***The Panel recommends that the Government of Manitoba divest Manitoba Hydro of its responsibilities for Demand Side Management.***
7. ***The Panel recommends that the Government of Manitoba mandate incremental annual Demand Side Management targets in the order of 1.5% of forecast domestic load (including codes and standards) over the long term.***
8. ***The Panel recommends that the Government of Manitoba establish a regulated, independent arm's-length entity that would be responsible for developing and implementing a plan to meet the mandated Demand Side Management targets.***
9. ***The Panel recommends that the Demand Side Management savings reported by the independent arm's-length entity be independently audited on an annual basis.***

10. ***The Panel recommends that until the independent arm's-length entity is established, Manitoba Hydro continue to address the barriers to lower income customer participation in its Demand Side Management programs.***
11. ***The Panel recommends that until the independent arm's-length entity is established, Manitoba Hydro proceed with its fuel switching and heating fuel choice initiatives to encourage customers to use natural gas for space and water heating.***

Rates and Ratepayer Impacts

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

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

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

12. ***The Panel recommends that the Government of Manitoba direct a portion of the incremental capital taxes and water rental fees from the development of the Keeyask Project to be used to mitigate the impact of rate increases on lower income consumers, northern and aboriginal communities.***
13. ***The Panel recommends that Manitoba Hydro relax its 75/25 debt-to-equity ratio policy to moderate its proposed electricity rate increases.***
14. ***The Panel recommends that Manitoba Hydro implement cost containment measures to moderate its proposed electricity rate increases.***

Actions in Support of a Clean Energy Future

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

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

APPENDIX 1

Order in Council and Terms of Reference

128/2013
No.

ORDER IN COUNCIL

ORDER

1. The Public Utilities Board (the "PUB") is assigned the conduct of a Needs For and Alternatives To review (an "NFAT review") of Manitoba Hydro's proposed preferred development plan, which includes the Keeyask and Conawapa Generating Stations, their associated domestic alternative current ("AC") transmission facilities, and a new Canada-United States of America ("USA") transmission interconnection.
2. Arthur Mauro and Mel Lazareck are appointed as members of the PUB, for the purpose of participating in the NFAT review, with terms to expire on such date as the PUB has fully completed its assigned duties in respect of the NFAT review, unless their appointments are revoked before that date by the Lieutenant Governor in Council.
3. The NFAT review will be conducted in accordance with the attached Terms of Reference.
4. This Order is effective on the date it is made.

AUTHORITY

The Public Utilities Board Act, C.C.S.M. c. P280, states:

Membership of board

4 The board shall be composed of such number of members, not less than three, as the Lieutenant Governor in Council may determine.

Appointment of members

7 The members shall be appointed by the Lieutenant Governor in Council, and shall be paid such remunerations as determined by the Lieutenant Governor in Council.

Term of office

9 Each member shall hold office during pleasure of the Lieutenant Governor in Council.

Power of board to perform assigned duties

107 The board may perform duties assigned to it

(b) by order of the Lieutenant Governor in Council; or

and Part I, in so far as it is applicable, applies to the carrying out of duties so assigned.

BACKGROUND

1. The Government of Manitoba wishes to have the PUB conduct an NFAT review of Manitoba Hydro's proposed preferred development plan for meeting a growing provincial demand for electricity and for taking advantage of export opportunities, which includes the Keeyask and Conawapa Generating Stations, their associated AC transmission facilities, and a new Canada-USA transmission interconnection, in accordance with the attached Terms of Reference.
2. Arthur Mauro and Mel Lazareck are being appointed to provide the PUB with the necessary capacity and expertise for the NFAT review. Manitoba has requested the chair of PUB to designate these new members, under subsection 15(6) of *The Public Utilities Board Act*, as the members who will conduct the NFAT review, together with any other members of PUB as he deems necessary for purposes of the review.

Healthy Living, Seniors and Consumer Affairs	
Initiating Department/Agency	
Authorized Officer	
APPROVED BY:	
Civil Service Commission	
Finance	
APPROVED AS TO FORM: April 16/2013	
Name: IRIS C. ALLEN	
Name	
Chief Legal Services	Initials
BILINGUAL: <input type="checkbox"/> Yes <input checked="" type="checkbox"/> No	

RECOMMENDED:
Minister of Healthy Living, Seniors and Consumer Affairs
APPROVED BY EXECUTIVE COUNCIL:
Presiding Member
ORDERED:
Lieutenant Governor
Date: April 17, 2013



472/2013

No.

ORDER IN COUNCIL

ORDER

1. Hugh Grant and Richard Bell, both of Winnipeg, are appointed as members of The Public Utilities Board (the "PUB"), for the purpose of participating in The Needs For and Alternatives To review of Manitoba Hydro's proposed preferred development plan, which includes the Keeyask and Conawapa Generating Stations, their associated domestic alternative current ("AC") transmission facilities, and a new Canada-United States of America ("USA") transmission interconnection, assigned to the PUB by Order in Council 128/2013 (the "NFAT Review").
2. The terms of office of Hugh Grant and Richard Bell expire on the date the PUB has fully completed the duties assigned to the PUB in respect of the NFAT Review in accordance with Order in Council 128/2013, unless their appointments are revoked before that date by the Lieutenant Governor in Council.
3. The remuneration to be paid to members of the Board is \$146.00 per meeting or \$255.00 per day, plus out-of-pocket expenses.
4. The appointments of Arthur Mauro and Mel Lazareck as members of the PUB for the purposes of the NFAT Review are revoked.
5. This Order comes into effect on the date it is made.

AUTHORITY

The Public Utilities Board Act, C.C.S.M. c. P280 states:

Membership of board

4 The board shall be composed of such number of members, not less than three, as the Lieutenant Governor in Council may determine.

Appointment of members

7 The members shall be appointed by the Lieutenant Governor in Council, and shall be paid such remunerations as determined by the Lieutenant Governor in Council.

Term of office

9 Each member shall hold office during pleasure of the Lieutenant Governor in Council.

Power of board to perform assigned duties

107 The board may perform duties assigned to it

... (b) by order of the Lieutenant Governor in Council;

... and Part I, in so far as it is applicable, applies to the carrying out of duties so assigned.

BACKGROUND

1. Under clause 107(b) of *The Public Utilities Board Act*, the Lieutenant Governor in Council, by Order in Council 128/2013, assigned to the PUB the conduct of the NFAT review.
2. Arthur Mauro and Mel Lazareck were appointed as members of the PUB for the purpose of participating in the NFAT review by Order in Council 128/2013, and they have resigned.
3. Hugh Grant and Richard Bell are being appointed to the PUB to provide it with the necessary capacity and expertise for the NFAT review. Manitoba has requested the chair of the PUB to designate Hugh Grant and Richard Bell, under subsection 15(6) of *The Public Utilities Board Act*, as the members of the PUB who will conduct the NFAT review, together with any other members of PUB the chair considers necessary for purposes of the NFAT review.

Tourism, Culture, Heritage, Sport and Consumer Protection
Initiating Department/Agency
Authorized Officer
Approved by
Civil Service Commission
Finance
APPROVED AS TO FORM:
NAME: GAIL E. MILNE
DATE: Dec 17, 2013
Civil Legal Services Initials: [Signature]
BILINGUAL: <input type="checkbox"/> YES <input checked="" type="checkbox"/> NO

RECOMMENDED:
[Signature]
Minister of Tourism, Culture, Heritage, Sport and Consumer Protection

APPROVED BY EXECUTIVE COUNCIL:
[Signature]
Presiding Member

ORDERED:
[Signature]
Lieutenant Governor

December 18, 2013
Date

Terms of Reference - Needs For and Alternatives To (NFAT) Review

NFAT review for Manitoba Hydro's proposed preferred development plan for the Keeyask and Conawapa Generating Stations, their associated domestic AC transmission facilities and a new Canada-USA transmission interconnection

INTRODUCTION

On January 13, 2011, the Government of Manitoba notified Manitoba Hydro (Hydro) of its intention to carry out a public Needs For and Alternatives To (NFAT) review and assessment of the corporation's proposed preferred development plan (Plan) for major new hydro-electric generation and Canada-USA interconnection facilities using an independent body.

On November 15, 2012 the Minister of Innovation, Energy and Mines announced that the Government of Manitoba had asked the Manitoba Public Utilities Board (PUB) to conduct the NFAT for the Keeyask and Conawapa Generating Stations and their associated transmission facilities. This document, including Appendix A, outlines the Terms of Reference for the NFAT.

THE PLAN

Hydro's Plan is intended to meet a growing provincial demand for electricity and take advantage of opportunities to export power to US customer utilities. The Plan includes the Keeyask and Conawapa Generating Stations, their associated domestic AC transmission facilities and a new Canada-USA transmission interconnection. Hydro has stated that its Plan is being brought forward now to take advantage of the proposed Canada-USA interconnection and long-term firm export sale opportunities that occur rather infrequently. Hydro's Plan is dependent upon developing a new transmission interconnection into the USA and entering into long-term firm export sales with US-based electric utilities Minnesota Power and Wisconsin Public Service.

Hydro asserts that the Plan will provide significant benefits to Manitobans. Hydro also asserts that the value proposition of its Plan is justified on a very broad basis, taking into consideration inherent uncertainties that exist over a reasonable range of future possible critical inputs into its business case, and that it is the best development option when compared to alternatives.

MANDATE

The NFAT will be conducted under the authority of section 107 of *The Public Utilities Board Act* ("The PUB Act"). PUB members designated by the Chair to conduct the NFAT under section 15(6) of The PUB Act will constitute the NFAT Panel (the "Panel"). Panel members will exercise their duty to conduct the assigned NFAT in accordance with The PUB Act and these Terms of Reference.

For greater certainty, in conducting the NFAT, the Panel members who are designated by the Chair to conduct the review:

- (a) may hear evidence *in camera* for the purpose of protecting Commercially Sensitive Information as defined in Appendix A, which forms a part of these Terms of Reference;
- (b) may exercise discretion over the access of any person to Commercially Sensitive Information; and
- (c) shall follow the Rules of Practice and Procedure of the PUB, as amended from time to time, if not otherwise dealt with under these Terms of Reference.

At the completion of its review, the Panel will provide a report to the Minister responsible for the administration of *The Public Utilities Board Act* (currently the Minister of Healthy Living, Seniors and Consumer Affairs) no later than June 20, 2014. The report will include recommendations to the Government of Manitoba on the needs for Hydro's preferred development Plan and an overall assessment as to whether or not the Plan is in the best long-term interest of the province of Manitoba when compared to other options and alternatives.

PUBLIC PARTICIPATION

The public will be encouraged to provide input and comment on the Plan as part of the NFAT.

SCOPE OF THE NFAT REVIEW

The Panel will review and assess the needs for and alternatives to Hydro's Plan. Its assessment will be based upon the evidence submitted by Hydro, intervenors and independent expert consultants used by PUB to assist in the NFAT. The Panel's report to the Minister will address the following items:

1. An assessment as to whether the needs for Hydro's Plan are thoroughly justified, and sound, its timing is warranted, and the factors that Hydro is relying upon to prove its needs are complete, reasonable and accurate. The assessment will take the following factors into consideration:
 - (a) The alignment of the Plan to Hydro's mandate, as set out in Section 2 of *The Manitoba Hydro Act*.
 - (b) The alignment of the Plan to Manitoba's Clean Energy Strategy and the Principles of Sustainable Development as outlined in *The Sustainable Development Act*.
 - (c) The extent to which the Plan is needed to address reliability and security requirements of Manitoba's electricity supply.
 - (d) The reasonableness, thoroughness and soundness of all critical inputs and assumptions Hydro relied upon for its justification of its needs. This should include Hydro's planning load forecast and future load scenarios, its demand and supply analysis, export expectations and commitments, and demand side management and conservation forecasts.
2. An assessment as to whether the Plan is justified as superior to potential alternatives that could fulfill the need. The assessment will take the following factors into consideration:
 - (a) If preferred and alternative resource and conservation evaluations are complete, accurate, thorough, reasonable and sound;
 - (b) The alignment of the Plan and alternatives to Manitoba's Clean Energy Strategy, *The Climate Change and Emissions Reductions Act* and the Principles of Sustainable Development as outlined in *The Sustainable Development Act*,
 - (c) The accuracy and reasonableness of the modeling of export contract sale prices, terms, conditions, scheduling provisions, export transmission costs, and the reasonableness of projected revenues;
 - (d) The reasonableness of forecasted critical inputs including construction costs, opportunity export revenues, future fuel prices, electricity market price forecasts, the determinants of those values, and export volumes;

- (e) The reasonableness of the scope and evaluation of risks and the benefits proposed to arise from the development and the reasonableness and the reliability of Hydro's interpretation of the most likely future outcomes as a result of climate changes, interest rate fluctuations, export market prices, domestic load fluctuations, droughts, competing technologies, fuel prices, carbon pricing, technology developments, economic conditions, Hydro's transmission positions and other relevant factors;
- (f) The impact on domestic electricity rates over time with and without the Plan and with alternatives;
- (g) The financial and economic risks of the Plan and export contracts and export opportunity revenues in relation to alternative development strategies;
- (h) The socio-economic impacts and benefits of the Plan and alternatives to northern and aboriginal communities;
- (i) The macro environmental impact of the Plan compared to alternatives;
- (j) If the Plan has been justified to provide the highest level of overall socio-economic benefit to Manitobans, and is justified to be the preferable long-term electricity development option for Manitoba when compared to alternatives.

Independent Expert Consultants

The Panel shall establish a process for the thorough review of any information that the Panel determines to be relevant to the conduct of the NFAT, including relevant Commercially Sensitive Information, as defined in Appendix A, subject to these Terms of Reference.

The Panel may use one or more independent expert consultant(s) for the purpose of the NFAT. In addition to such other questions and issues as the Panel may determine they should examine, the independent expert consultant(s) shall be expected to critically examine the following:

- (a) the high level forecasts of export revenues that are filed by Hydro and whether the forecasts appropriately and accurately reflect the export contracts, including Commercially Sensitive Information.

- (b) the accuracy and reasonableness of Hydro's approach to producing an assessment of financial risks (including drought), the assessment of which is derived using Commercially Sensitive Information;
- (c) the appropriateness and correct application of methodologies that cannot be publicly disclosed by Manitoba Hydro because they contain Commercially Sensitive Information, such as whether Hydro's approach to comparing generation sequences follows sound industry practice;
- (d) whether high level summaries filed by Hydro of Net Present Values and Internal Rates of Return which are derived from Commercially Sensitive Information reflect sound assumptions and calculations; and
- (e) the accuracy and soundness of Hydro's calculation of a consensus forecast of future market prices for electricity and fuels which is derived from Commercially Sensitive Information.

The PUB shall hire the independent expert consultant(s).

The independent expert consultant(s) shall provide a report(s) to be filed in evidence on the public record, which shall contain their analysis of the submissions filed by Hydro, with sufficient information to satisfy the Panel that the review was conducted with due diligence. The report(s) shall not draw conclusions as to the needs for or alternatives to the Plan, which is the role of the Panel.

The independent expert consultant(s) shall be available for cross-examination at the public hearing, and shall be available as a resource to legal counsel for registered intervenors as deemed necessary by the PUB to prepare for the cross-examination of Hydro witnesses on Commercially Sensitive Information.

The independent expert consultant(s) may also provide such advice to the Panel, and file such report(s) with the Panel *in camera*, that contain, reference, or analyse Commercially Sensitive Information in sufficient detail to satisfy the Panel. Cross-examination of the independent expert consultant(s) on such issues shall be permitted *in camera*.

The independent expert consultant(s) shall not quote in their publicly filed report(s) Commercially Sensitive Information or information that would enable a third party to reverse-engineer Commercially Sensitive Information ("reverse-engineer" means to discover, synthesize or otherwise recreate the Commercially Sensitive Information following a detailed examination). No public cross-examination of the independent

expert consultant(s) shall take place with respect to Commercially Sensitive Information. The independent expert consultant(s) will be required to execute a non-disclosure agreement satisfactory to Hydro and the Panel.

NOT IN SCOPE

The following items are not in the scope of the NFAT:

- The Bipole III transmission line and converter station project;
- The Pointe Du Bois project;
- The commercial arrangements between Hydro and its aboriginal partners for the development of the proposed hydro-electric generating facilities (the impacts of these are included in the cost of the projects that are part of the Plan);
- The environmental reviews of the proposed projects that are part of the Plan, including Environmental Impact Statements (these will be conducted through individual processes by the Manitoba Clean Environment Commission (“CEC”), and where possible the impacts of the matters to be considered by the CEC are included in the costs of the projects that are part of the Plan);
- Aboriginal consultation pursuant to Section 35 of the *Constitution Act* (this is conducted as a separate Crown-Aboriginal consultation process);
- Any past Hydro development proposals or government assessments of past development proposals, including past NFATs;
- Historic environmental costs.

APPENDIX A
PROVISIONS FOR THE PROTECTION OF COMMERCIALY
SENSITIVE INFORMATION:

Transparency

The Panel is directed to conduct the NFAT in a transparent and public process. However, in conducting the NFAT, the Panel is to ensure adequate protection of any information the disclosure of which may reasonably be expected to cause undue financial loss to Manitoba Hydro (“Hydro”) or any of its contractual counterparties or to harm significantly Hydro’s or its contractual counterparties’ or domestic customers’ competitive position, including, but not limited to, any sections of the following documents containing such information (collectively, “Commercially Sensitive Information”):

- (a) any and all export contracts and term sheets now or hereafter in existence for the purchase and sale of power and energy entered into between Hydro and its customers in the United States of America, including but not limited to the export contracts and term sheets commonly described as follows: Minnesota Power 250 MW Energy Exchange Agreement; Minnesota Power 250 MW Power Sale Agreement; Wisconsin Public Service 100 MW Power Sale Agreement; Wisconsin Public Service 108 MW Energy Sale Agreement; Wisconsin Public Service Term Sheet, Northern States Power 375/325 MW System Power Sale Agreement; Northern States Power 125 MW System Power Sale Agreement, and Northern States Power 350 MW Seasonal Diversity Agreement (collectively, “Export Contracts”);
- (b) the internal, non-public load forecast prepared by Hydro on an annual basis (collectively, “Load Forecast”); and
- (c) the Hydro document dated September 24, 2010 titled “THE 2010/11 POWER RESOURCE PLAN, Report PPD #10-07” and any further existing or future power resource plans hereinafter developed by Hydro (collectively, “Power Resource Plan”)

Document Filings and Evidence

In conducting the NFAT, the Panel shall be able to require the production, from Hydro, of any documents and other such evidence as the Panel determines to be relevant to

the conduct of the NFAT within the scope of the Terms of Reference from the Province of Manitoba. The procedures for filings and evidence shall be as set out below:

(a) Public Filings

Any documents that do not contain Commercially Sensitive Information are to be filed on the public record. As part of its NFAT submission Hydro shall file on the public record copies of its Export Contracts, Load Forecast and Power Resource Plan, with details considered by Hydro to be Commercially Sensitive Information redacted.

To the extent that information necessary for the conduct of the NFAT cannot be made public due to the presence of Commercially Sensitive Information, Hydro shall file on the public record high level summaries and reports that incorporate the relevant information, at a level of summary and aggregation which will not disclose Commercially Sensitive Information.

Any evidence before the Panel shall be public, other than evidence with respect to Commercially Sensitive Information, which testimony shall be received in camera as further described in (b) below. To the extent that it deems practical, the Panel shall limit the scope of *in camera* proceedings so that the major issues in the NFAT review can be canvassed and discussed in public.

(b) Confidential Filings

Any documents that the Panel determines to be relevant but that contain Commercially Sensitive Information are to be filed with the Panel in confidence in unredacted form, including unredacted copies of the Export Contracts, Load Forecast and Power Resource Plan.

On an *in camera* basis, the Panel may:

- (i) ireview the complete, unredacted versions of Hydro documents that contain Commercially Sensitive Information; and
- (ii) permit evidence with respect to Commercially Sensitive Information.

Access to *In Camera* Evidence

Based on the *in camera* review, the Panel may choose to publish findings and conclusions about export revenues, forecast market prices and the like, to inform the public discussion and serve as inputs to further analysis and review by participants at

the public hearing, or it may choose to reserve comment until the conclusion of the hearing.

The documents filed and evidence adduced *in camera* shall not be made public, other than through the high-level summaries as described above, and shall only be disclosed to or shared with the following persons, on the terms and conditions as noted below:

1. Members of the Panel, the Board's Executive Director and Board staff may review Commercially Sensitive Information and participate in the *in camera* process for the purpose of carrying out their specific duties with respect to the NFAT without having to sign an undertaking or a non-disclosure agreement.
2. Legal counsel of record of the Board and counsel for registered interveners may review Commercially Sensitive Information and participate in the *in camera* process upon execution of an undertaking to the Panel in a form agreeable to the Panel and Hydro.
3. Any independent consultant(s) appointed by the Panel and any non-staff Panel advisors with a need to know, as determined by the Chair, may review Commercially Sensitive Information and participate in the *in camera* process upon execution of a non-disclosure agreement in a form agreeable to the Panel and Hydro.

Subject to the following dispute resolution provision, the Panel will not publish Commercially Sensitive Information in Orders or other public documents or include information that would enable a third party to reverse engineer Commercially Sensitive Information. The Panel will establish procedures to protect the documents and evidence from inadvertent disclosure and will instruct each individual who receives access to do the same. If the Panel so chooses, it may solicit Hydro's comments on particular documents that are in the process of being prepared in the interests of avoiding inadvertent disclosures.

Dispute Resolution Regarding Commercially Sensitive Information

If, during the *in camera* review, the Panel identifies any Commercially Sensitive Information, other than third party proprietary price forecasts, which the Panel considers would be beneficial to place on the public record at the NFAT, the Panel may refer those matters in dispute to a neutral third party to be agreed upon between the Panel and Hydro. The third party will receive written submissions and make a decision thereon, on an expedited basis, which decision will be given effect to in the proceedings before the Panel. In arriving at any such decision, the neutral third party shall

specifically take into account the general undesirability of making disclosure of any Commercially Sensitive Information that may have been furnished to Hydro by third parties, in reliance upon contractual commitments by Hydro to maintain confidentiality, and the importance of maintaining such confidences.

APPENDIX 2 NFAT Panel Member Biographies

Régis Gosselin, B ès Arts, MBA, CGA, Chair

Appointed to Public Utilities Board April 2012

Former Director of Corporate Services for the Canadian Grain Commission, this member has worked for the Fédération des Caisses Populaires and also Entreprise Saint-Boniface, a community economic development organization. He is a past Chair of the Société d'assurances dépôts des caisses populaires du Manitoba, Caisse populaire de Saint-Boniface and Centre Youville.

Richard Bel, B.A., M.A. , M.Sc.

Appointed to Public Utilities Board December 2013

Co-owner and managing partner of the Fort Garry Hotel since 1994, this member is also the current Chair of the Forks North Portage Partnership. In addition to being a former owner of various Winnipeg restaurants, he was an Assistant Professor of Economics at Kobe University (Kobe, Japan) and the University of Manitoba. He has been appointed a member to examine Manitoba Hydro's Preferred Development Plan.

Hugh Grant, Ph.D. (Economics)

Appointed to Public Utilities Board December 2013

Professor of Economics at the University of Winnipeg, he teaches on indigenous economic development in the University's Masters of Development Practice program. He also currently serves as the President of the University of Winnipeg Faculty Association. He obtained his Ph.D. in Economics from the University of Toronto. In addition to his academic research on labour economics, health economics and Canadian economic development, he has engaged in policy work with a range of organizations including Industry Canada, the Law Commission of Canada, Manitoba Family Services and Consumer Affairs, the Public Interest Law Centre and the Canadian Royal Commission on Aboriginal Peoples. He also has previous experience as a consultant to aboriginal associations on comprehensive land claims. He was appointed a member to review Manitoba Hydro's Preferred Development Plan.

Marilyn Kapitany, BSc. Honours, MSc.

Appointed to Public Utilities Board July 2012

A former senior Federal Government executive responsible for Western Economic Diversification Canada. Former Regional Director General of Indian and Northern Affairs Canada (Manitoba) as well as Director of Industry Services at the Canadian Grain Commission.

Past Chair of the National Board of YM-YWCA of Canada and appointed as Canada's International Representative in 2014. Marilyn is a member of the Riverview Health Centre Board. Former Chair of the YM-YWCA of Winnipeg Board, and past member of Assiniboine Park Conservancy Board and Association of Professional Executives.

Larry Soldier

Appointed to Public Utilities Board July 2012

Former Chief of the Swan Lake First Nation.

Serves on the Board of Directors for Youville Centre. Former Vice-Chairman of the Dakota Ojibway Tribal Council and Dakota Ojibway Child and Family Services. Served on numerous committees which includes former Chairperson of the Small Business Management and Dev. Committee of Keewatin Community College and past member of Chiefs Committee on Treaties and Self-Determination. Former Chairman of the Regional Advisory Board, Alcoholism Foundation of Manitoba. Served as City Councillor for the City of Thompson. Proprietor since 2006.

APPENDIX 3 Chronology of Events

January 13, 2011 – The Government of Manitoba notifies the Manitoba Hydro-Electric Board (Manitoba Hydro) of its intention to carry out a public Needs For and Alternatives To (NFAT) Review and assessment of the Manitoba Hydro's proposed Preferred Development Plan (PDP) for major new hydro-electric generation and Canada-USA interconnection facilities using an independent body.

November 16, 2012 – The Minister of Innovation, Energy and Mines announces that the Government of Manitoba has asked the Manitoba Public Utilities Board (PUB) to conduct the NFAT Review for the Keeyask and Conawapa Generating Stations and their associated transmission facilities.

April 17, 2013 – By Order in Council 128/2013, the Government of Manitoba assigns to the PUB the conduct of a Needs For and Alternatives To (NFAT) Review Manitoba Hydro's Preferred Development Plan, which includes constructing the Keeyask and Conawapa Generating Stations, their associated domestic alternating current transmission facilities and a new Canada-United States transmission interconnection. The NFAT Review is to be conducted in accordance with the Terms of Reference for attached to the Order.

April 25, 2013 – The Government of Manitoba issues a news release respecting the NFAT Review.

May 16, 2013 – The NFAT Panel of the Public Utilities Board holds first Pre-Hearing Conference to determine Interveners for NFAT Review.

June 11, 2013 – The Panel issues Order 67/13 granting Intervener Status with respect to the NFAT Review to the following five applicants:

- Consumers' Association of Canada (Manitoba) Inc. (CAC);
- Green Action Centre (GAC);
- Manitoba Industrial Power Users Group (MIPUG);
- Manitoba Keewatinowi Okimakanak Inc. (MKO); and
- Manitoba Metis Federation (MMF).

The following four applicants were denied Intervener Status:

- Peguis First Nation;

- The Pimicikamak at Cross Lake;
- Kaweechiwasik Inninuuk; and
- Manitoba Public Interest Research Group.

July 15, 17, 2013 – Manitoba Hydro holds first NFAT Technical Conference.

August 9, 2013 – The Panel issues Order 91/13 dismissing applications by Pimicikamak and the Manitoba Public Interest Research Group to review and vary Order 67/13, which dismissed applications by the respective applicants to obtain Intervener status in NFAT Review.

August 9, 2013 – The Panel issues Order 92/13, which addresses a number of procedural issues arising out of Order 67/13. The Order provides preliminary approval of Interveners' consultants and expert witnesses, and draft budgets.

This order also defines the terms "macro environmental" and "socio-economic" for the purposes of the Review.

Macro environmental impact assessment is defined as: A critical analysis of the macro environmental impacts and benefits of Manitoba Hydro's Preferred Development Plan and alternative Plans. Specifically this refers to the collective macro-economic consequences of changes to air, and, water, flora and fauna, including the potential significance of these changes, their equitable distribution within and between present and future generations.

Socio-economic impact and benefits is defined as: A critical analysis of the socio-economic impacts and benefits of Manitoba Hydro's Preferred Development Plan and alternative Plans. Specifically, a high level summary of potential effects to people in Manitoba, especially Northern and Aboriginal communities, including such things as employment, training and business opportunities; infrastructure and services; personal family and community life; and resource use.

August 16, 2013 – Manitoba Hydro files its NFAT Business Case Submission with the PUB.

August 2013 – The Panel engages Independent Expert Consultants to assist the Panel in the NFAT Review.

September 4, 2013 – The Panel holds second Pre-Hearing Conference.

September 5-6, 2013 – Manitoba Hydro holds second Technical Conference.

September 2013 – The Scopes of Work for the Independent Expert Consultants are established.

September 30, 2013 – The Panel holds a “motion day” hearing to deal with a motion made by Manitoba Hydro with respect to First Round Information Requests and issues raised by counsel for the independent expert consultants .

October 4, 2013 – The Panel issues procedural Order 119/13 in respect of matters raised at the September 30, 2013 "motion day" hearing. The Order establishes a process to deal with Information Requests directed to Manitoba Hydro and issues raised by the Independent Expert Consultants.

October 21, 2013 – The Panel issues Order 126/13, an Erratum order in respect of Order 119/13.

October 21, 2013 – The Panel issues Order 127/13, which relates to procedural matters arising from the September 4, 2013 Pre-Hearing Conference, including establishing a communications protocol for the Independent Expert Consultants.

December 18, 2013 – By Order in Council 472/2013, the Government of Manitoba appoints Dr. Hugh Grant and Mr. Richard Bel to the Public Utilities Board for the purpose of participating in the NFAT Review.

February 27, 2014 – The Panel holds a Presenters day in Winnipeg to hear a number of organizations and individuals who wished to make their views on the Preferred Development Plan known to the Panel.

March 3, 2014 – The oral evidentiary phase of the NFAT Review hearings begins.

March 4, 2014 – The Panel issues Order 22/14, which partially grants Manitoba Hydro's motion to strike portions of the evidence of Whitfield Russell Associates provided on behalf of the Manitoba Métis Federation (MMF) on that grounds that the evidence is outside scope of the Terms of Reference for the NFAT Review.

April 9, 2014 – The Panel issues Order 35/14 granting the MMF's motion to review and vary Order 22/14 and accepting the revised redactions proposed by MMF to the evidence of Whitfield Russell Associates.

May 13, 2014 – The evidentiary portion of the NFAT Review hearings concludes.

May 14, 2014 - The Panel holds a Presenters day in Thompson, Manitoba to hear from a number of organizations and individuals who wished to make their views on the Preferred Development Plan known to the Panel.

May 20-26, 2014 – The Panel hears closing submissions from Interveners and Manitoba Hydro.

June 20, 2014 – The NFAT Review report is submitted to the Minister responsible for the administration of *The Public Utilities Board Act*, as required by the Terms of Reference.

APPENDIX 4 Independent Expert Consultant Scope of Work

Independent Expert Consultant	Scope of Work (High-Level Description)
Elenchus Research Associates Inc.	Load forecasting; Demand side management (DSM); energy efficiency
La Capra Associates, Inc.	Power resource planning, economic evaluation, business case and risk analysis, transmission economics, export contracts, financial modelling
EnerNex (as a subcontractor to La Capra Associates, Inc.)	Wind matters
Knight Piésold Ltd.	Construction management, capital costs
MNP LLP	Macro-environmental issues
MPA Morrison Park Advisors Inc.	Commercial evaluation of Preferred Development Plan
Potomac Economics, Inc.	Midcontinent Independent System Operator (MISO); export markets, prices and revenues
Power Engineers, Inc.	Transmission line construction and management
TyPlan Consulting Ltd.	Socio-economic impacts and benefits

SCOPES OF WORK: The detailed Scopes of Work for the Independent Expert Consultants can be found on the PUB website.

<http://www.pub.gov.mb.ca/nfat/index.html>

REPORTS: The reports prepared by the Independent Expert Consultants can be found on the PUB website.

<http://www.pub.gov.mb.ca/nfat/index.html>

APPENDIX 5 Interveners

By Order 67/13, the Public Utilities Board granted Intervener status to the Intervener Applicants named below. Each Intervener was approved with respect to the issues listed for the respective Intervener.

Consumers' Association of Canada (Manitoba) Inc. (CAC)

- Reliability of Manitoba Hydro's forecast relating to load, capital costs, export revenues, and enhanced transmission capacity
- Risk Assessments as detailed in CAC's written Application for Intervener Status
- Analytical consideration of alternatives to Manitoba Hydro's Preferred Development Plan (PDP) including risk diversification, energy efficiency and non-hydroelectric options such as natural gas and wind
- Sustainability of Manitoba Hydro's PDP and comparison to alternatives
- Rate impacts on Manitoba Hydro's domestic ratepayers – including those on fixed and low incomes
- Macro-Environmental Impacts of the PDP and alternatives
- Socio-Economic impacts and benefits of Manitoba Hydro's PDP – compared to alternatives – in regard to northern and aboriginal communities as well as all Manitobans

Green Action Centre (GAC)

- Forecasts and risks associated with domestic load, export commitments and export pricing
- Use of Demand Side Management and alternative energy initiatives
- Marginal costs of Manitoba Hydro's Preferred Development Plan ("PDP") and alternatives including DSM
- Alternatives to Manitoba Hydro's PDP together with integration into a diversified portfolio and consideration of such contributions to Risk Management.

Manitoba Industrial Power Users Group (MIPUG)

- Impact on domestic rates, including long term impacts
- Risks to domestic customers through Manitoba Hydro's investment in subsidiaries, export ventures and new Programs

- Alternatives to Manitoba Hydro's Preferred Development Plan including demand side management programs
- Risks including long-term financial and economic risks and the financial liability of Manitoba Hydro

Manitoba Keewatinowi Okimakanak Inc. (MKO)

- The socio-economic impacts and benefits of Manitoba Hydro's Preferred Development Plan ("PDP") and alternatives in respect of the MKO First Nations
- The impact of domestic electricity rates over time, with and without the PDP and with alternatives

Manitoba Métis Federation (MMF)

- The impact on domestic rates
- Financial and economic risks
- Socio-economic impacts and benefits of Manitoba Hydro's Preferred Development Plan ("PDP") and alternatives to Northern and Aboriginal communities
- Macro-environmental Impacts of the PDP compared to alternatives
- Whether the PDP is the highest level of overall socio-economic benefit to Manitoba

REPORTS: The reports prepared by Intervener experts can be found on the PUB website.

<http://www.pub.gov.mb.ca/nfat/index.html>

APPENDIX 6 Summary of Intervener Closing Submissions

For the completeness of the record, this Appendix provides a summary of the closing submissions of each Intervener. The Panel regrets any errors or omissions that may have occurred in summarizing Intervener submissions. The full submissions can be accessed at <http://www.pub.gov.mb.ca/nfat>.

Consumers' Association of Canada (Manitoba) Inc. (CAC)

The Consumers' Association of Canada (Manitoba) Inc. (CAC) submitted that the Preferred Development Plan has suffered painful evidentiary blows, and that the most recent economics make it untenable. In CAC's view, the business case was premised on certain expected capital costs, a robust U.S. economy, and carbon prices developing in the United States. However, export price projections are now significantly lower than they used to be, while the capital cost of the Preferred Development Plan has gone up. CAC called the availability of shale gas a "game changer." In addition, CAC stated that carbon pricing is still uncertain, the U.S. economy has experienced a paradigm shift, grid parity is a risk during the planning horizon, and both wind and solar energy have become more feasible. CAC submitted that Manitoba Hydro is a price taker in the U.S., and thus is exposed to the cost of alternative technologies and market rates, being unable to obtain pricing based on its own cost structure. According to CAC, this confluence of factors eviscerated the "decade of returns" previously envisioned by Manitoba Hydro.

CAC was critical of the presence of sunk costs in Manitoba Hydro's analyses, which make non-hydro alternatives less competitive than they would otherwise be. CAC further stated that the inclusion of Bipole III costs and the Gillam expansion, both of which form part of Manitoba Hydro's northern strategy, further harm such alternative plans.

CAC further noted that the changes to a number of factors in Manitoba Hydro's analysis, including changed capital costs and economics, the revelation that the most economically competitive plan, which would have had a 250 MW interconnection, was not viable, and the exclusion of certain updates from new analyses all led to "resource planning on the fly."

CAC concluded that Manitoba Hydro's analysis did not constitute good integrated resource planning. According to CAC, Manitoba Hydro's plan suffers from an overstatement of demand, and the failure to include demand side management (DSM)

as an integral element of resource planning constitutes a fatal flaw in Manitoba Hydro's business case. CAC noted that the rate of electricity demand growth in North America has been decreasing over the past decade and that there is the possibility of a zero-growth future. All of this creates risk when investing in a "merchant plant", i.e., a plant designed primarily for export.

CAC recommended that DSM Level 2 savings should be anticipated to extend beyond 2018, and that multi-year DSM targets should be imposed on Manitoba Hydro and reviewed by the Public Utilities Board on an annual basis.

CAC considered the impact of the Preferred Development Plan on ratepayers to be unacceptable, and states that electricity is an essential service and basic necessity for lower income consumers, who would have to pay an increasingly large percentage of their budget for electricity under the proposed rate increases. This issue is amplified for northern and aboriginal ratepayers who pay disproportionately large hydro bills. CAC stated that lower income customers face significant barriers in accessing DSM programs that could improve affordability, which means such programs should be straightforward for lower income ratepayers and, ideally, not involve a cost to the ratepayers. CAC recommended that a stakeholder consultation process be initiated to remove barriers, and Manitoba Hydro report on the issue in six months to one year.

CAC submitted that the Preferred Development Plan was not justified, and that no further funds should be spent on protecting a Conawapa in-service date without express authority of the Public Utilities Board following an updated consideration of the business case based on modern integrated resource practice. Otherwise, CAC submitted there were three feasible options:

1. Proceed with economic DSM; no build until domestic need date;
2. Proceed with economic DSM and have Manitoba Hydro return with updated information related to integrated resource planning, export opportunities, and a regional cumulative effects assessment; or
3. Proceed with economic DSM, Keeyask, and the 750 MW intertie with conditions.

Despite the fact that two of its expert witnesses spoke in favour of developing Keeyask, CAC submitted that the best option would be Option 2, which should be followed by a further review process. However, if the Panel approves Option 3, CAC recommended a phased approach, in which Manitoba Hydro, until 2018, would be required to expand its DSM program, provide annual cost reporting, and provide a rate impact mitigation strategy. In addition, CAC would like to see the regional cumulative effects assessment

reviewed by the Clean Environment Commission. In Phase II, after the construction of Keeyask, CAC would like to see Manitoba Hydro file an updated business case for any further generation based on a comprehensive integrated resource planning framework.

If Keeyask proceeds, CAC further suggested the implementation of a Green Energy Benefit to compensate ratepayers for the disproportionate share of risk borne by them. This benefit could either be directed to persons of modest means or made available to a broader spectrum of ratepayers.

Green Action Centre (GAC)

The Green Action Centre (GAC) supported the target set out in *TomorrowNow: Manitoba's Green Plan* to make Manitoba one of the most sustainable places to live on earth. GAC noted that rate impacts are just one consideration among many others for the NFAT Panel to take into account. Specifically, GAC submitted that the NFAT Panel ought to consider broader societal issues such as jobs and economic benefits, revenue flows to the Province from water rentals, taxes and the debt guarantee fee, and the impact of the Preferred Development Plan on greenhouse gas emissions both within and outside Manitoba.

GAC submitted that Manitoba Hydro's evidence was deficient in failing to treat Demand Side Management (DSM) as an alternative to new generation and wind as an alternative to northern dams. GAC stated that the evidence of La Capra Associates, Mr. Chernick, Mr. Dunskey and Mr. Harper suggests that Manitoba Hydro can offset all currently projected load growth with DSM measures. According to GAC, DSM reduces line losses and emissions, creates jobs, and has proved to be a dependable resource for other utilities.

Of particular concern to GAC was fuel choice. GAC stated that Manitoba Hydro has insufficiently addressed this matter. GAC pointed to what it calls market failures with respect to the installation of electric space and water heat for the convenience of builders and contractors rather than homeowners. In GAC's view, the issue of fuel choice extends to the projected new pipeline load. GAC stated that if the pipeline companies had to pay export market rates for electricity, there would be little benefit for them in choosing electric pumping stations.

GAC is critical of Manitoba Hydro's DSM Level 2 program, stating that other utilities manage to achieve sustained savings of 1.3% per year. In contrast, Manitoba Hydro's proposed program ramps up to 2.1% in the short term, but then decreases gradually to only 0.2% by 2028/29, even including conservation rates and customer generation, neither of which are usually counted in DSM savings. According to GAC, Manitoba

Hydro's 41% probability of new supply being required in 2023 could be significantly reduced with increased DSM and fuel switching. GAC further stated that additional load will not appear overnight, and if growth turns out higher than expected, Manitoba Hydro could add wind resources within two years at a lower cost and at less risk than Keeyask.

According to GAC, the levelized cost of energy (LCOE) of wind would be lower than the LCOE for Keeyask and Conawapa. GAC suggested that for purposes of estimating the capital cost of wind, Manitoba Hydro should use the U.S. Department of Energy's market report as a starting point and determine cost differences specifically between average costs and those expected in Manitoba. Manitoba Hydro should further consult with wind developers as to expected project life and take into account technological and costing trends. GAC further suggested developing several wind sites to a preliminary level so that in the case of supply shortfalls, wind projects could be brought into commercial operation in approximately two years.

GAC recommended that Manitoba Hydro should pursue aggressive DSM, including conservation rates and fuel switching, but acknowledged that vulnerable persons with a high energy burden will require bill mitigation through targeted retrofit and efficiency programs, special rate design and, in some, cases, discounted bills. On the issue of rate design, GAC stated that stakeholder consultation could provide a valuable benefit.

GAC supported the approval of Keeyask and 750 MW intertie, noting that the intertie is the most important asset in Manitoba Hydro's plan and provides economic imports as well as firming capability for wind and solar power. GAC submitted that no case has been made to approve Conawapa, and argued forcefully against new gas generation, especially for baseload. GAC stated that while using gas for space and water heating leads to greenhouse gas reductions, the opposite is true if gas is used to generate electricity.

GAC further submitted that Manitoba Hydro should implement integrated resource planning, including an evaluation of wind integrated and the identification of trigger events to revive Conawapa.

Manitoba Industrial Power Users Group (MIPUG)

The Manitoba Industrial Power Users Group (MIPUG) noted that under Manitoba Hydro's initial numbers, industry could pay an additional \$400 million in rates over the next 20 years compared to viable alternatives. MIPUG expressed frustration that the NFAT Review was made difficult by four factors, namely (1) the presence of over \$1.4 billion of sunk costs which would have to be written off with all non-Keeyask plans, (2)

the fact that the 250 MW transmission line option has effectively been dropped, (3) the absence of a broad resource planning review before the current project-specific review, and (4) the high rate impacts ratepayers are already bearing for Bipole III, a project without associated revenue benefits.

In MIPUG's view, plans that are focused on meeting domestic need rather than export opportunities remain credible, since with economic DSM the required in-service date for new generation could be pushed back to at least 2024. To that extent, MIPUG suggested a possible scenario in which a gas unit would be built before Keeyask, pushing Keeyask back to 2031 or later. MIPUG noted that all plans must consider that electric load forecasts may be reasonable over the short term, but significantly differ from the future reality over the medium to long term. It further observed that Manitoba Hydro's goal of a maximum 10% error over 10 years equates to approximately 3,000 GWh, which is similar to the output from Keeyask.

Nonetheless, MIPUG submitted that a K19/750 MW plan had significant benefits, among them cross-border transmission, the value of which had not been fully captured in the Manitoba Hydro's analysis. It suggested that K19/750 MW could in fact be the preferred plan, but only if mitigation measures were instituted. Specifically, MIPUG suggested that Manitoba Hydro should relax its financial standards such that it does not have to return to 75%/25% debt-to-equity and a 1.20 interest coverage ratio within the next 20 years. MIPUG pointed to several rate-design alternatives filed by Manitoba Hydro that would result in decreased retained earnings at the end of 20 years which, in MIPUG's view, would keep rate increases similar to the increases expected for an all-gas alternative, but would still allow Manitoba Hydro to absorb drought risk, which MIPUG noted does not exceed \$3.568 billion even under a high-export price scenario. MIPUG also suggests that transfers to the provincial government through capital taxes and water rental fees should be reduced during the period in which customers face upward pressure on rates. MIPUG stated that under the current scenario, the risk for the K19/750 MW plan is borne by ratepayers, while the Province of Manitoba would reap significant benefits without any negative downside risk.

MIPUG was supportive of DSM Level 2 if it is realistic and can be achieved without adverse rate impacts. In MIPUG's view, this would involve a focus on the Program Cost Administrator Test (PACT) and the Rate Impact Measure (RIM) test, and less reliance on the Total Resource Cost (TRC) test currently applied by Manitoba Hydro. The DSM program should also provide sufficient support for self-generation by industrial customers, as well as an encouragement of curtailable load to derive capacity benefits. MIPUG specifically took issue with Manitoba Hydro's cap on the Curtailable Service Program (CSP) and its closure to new entrants.

While MIPUG did not support a plan that involves Conawapa at this time, noting that it brings no benefits and substantial risks, MIPUG was supportive of “minimal” spending of \$100-\$150 million to protect a 2026 or 2031 Conawapa in-service date. MIPUG submitted that if Manitoba Hydro were to consider that the proposed U.S. 750 MW interconnection can be expanded to 1,100 MW in the future, the value of Conawapa energy could increase. Furthermore, Conawapa could provide a basis for Manitoba Hydro to be able to sell its stake in the 750 MW interconnection in the future.

MIPUG did not support a revision to Manitoba Hydro's import criteria without a detailed and thorough consideration of the risks from such a revision.

MMF

The Manitoba Métis Federation (MMF) submitted that while Manitoba Hydro consulted with Aboriginal communities and shared benefits with the Keeyask Cree Nations, Manitoba Hydro did not apply its proactive approach to partnership to the Métis community. For example, Manitoba Hydro's advisory group on employment only contained Aboriginal representation from the Keeyask Cree Nations despite Métis constituting a significant part of Manitoba Hydro's workforce. The MMF also criticized the fact that there are no adverse effects agreements with respect to transmission impacts, despite over \$200 million having been paid for adverse transmission impacts associated with Wuskwatim. In that context, the MMF stated that the assumption in Manitoba Hydro's Multiple-Account Benefits-Cost Analysis that residual impacts would be minimized through mitigation and compensation does not apply to the Métis community, since no compensation was provided to the Métis and mitigation of transmission impacts was not included. The MMF also stated that the cost of Section 35 consultation should have been included in costs, even if such consultation was outside the scope of the NFAT Terms of Reference.

With respect to environmental issues, the MMF cautioned that findings from the Clean Environment Commission and the Canadian Environmental Assessment Agency apply only to Keeyask, but not to Conawapa or other alternatives, and that a regional cumulative effects assessment had not yet been provided. The MMF further stated that information provided by Manitoba Hydro in the course of the NFAT Review did not deal with the collective impact of the Preferred Development Plan.

With respect to rate impacts, the MMF submitted that Manitoba Hydro should diversify its DSM and fuel switching strategy and expand education programs targeted to northern and aboriginal communities. For example, in the MMF's view, not enough

attention was paid to fuel switching to biomass, despite woodstoves being a viable source of heat for many aboriginal communities.

With respect to financial and economic risk, the MMF stated that the 78-year study period was too long and tends to favour high-risk hydro-centric plans requiring a large capital investment. The MMF submitted that lower rates in the long term at the cost of significant near-term rate increases would result in intergenerational inequity. In the MMF's view, the Preferred Development Plan was further dependent on the magnitude of future exports and future export prices, the latter of which have been declining over successive forecasts since 2009. The MMF also submitted that if the cost of Bipole III were to be added to the Preferred Development Plan, it would increase the in-service cost of Keeyask from approximately 10¢/kWh to 13¢/kWh, which would not recover the cost of Bipole III and Keeyask until the mid-2040s. The MMF further submitted that treating Bipole III as a sunk cost to be included in all development plans had the effect of biasing the analysis in favour of the Preferred Development Plan.

On the issue of transmission risk, the MMF stated that the deterministic standard applied by Manitoba Hydro to transmission risk could have been met by strengthening interconnections to the United States, and that any reliability benefits from Bipole III would drop with the addition of Keeyask and disappear completely with the addition of Conawapa. The MMF concluded that Manitoba Hydro is placing "too many eggs in one basket" by relying on the northern generation corridor and that greater emphasis should be placed on the need to improve import capability.

The MMF suggested that La Capra's No New Generation "Plan 17" remains an economic option, and that a U.S. 500 kV transmission line without further hydroelectric capacity would improve reliability and increase both the ability to export and import power. The MMF moreover argued that further consideration should be given to this plan, including pursuing additional diversity exchange agreements.

The MMF also submitted that wind could form part of an optimized plan to delay new hydro generation until 2030, which would delay the construction of any new hydro until after the completion of a regional cumulative effects assessment. In the MMF's view, wind as a resource not only provides for greater flexibility, but would allow communities to participate in small-scale renewable projects.

As a procedural recommendation, the MMF submitted that the NFAT Panel should recommend an amendment to existing legislation requiring Manitoba Hydro to undergo an NFAT before any major capital expenditure as a precondition to recovering its costs in rates.

Manitoba Keewatinowi Okimakanak Inc. (MKO)

Manitoba Keewatinowi Okimakanak Inc. (MKO) intervened on issues relating to the socio-economic impact of the Preferred Development Plan and alternatives on the MKO First Nations and the impact of domestic electricity rates over time. MKO's primary focus was the impact of rate increases on citizens of the MKO First Nations. MKO identified its member citizens as being Residential ratepayers and the First Nation governments to be General Service ratepayers, including the four communities receiving diesel-generated power.

In MKO's view, the planned rate increases tied to the Preferred Development Plan will have a disproportionate impact on the Residential and General Service ratepayers in the First Nations areas, as most citizens there are lower income customers and spend a higher proportion of their budget on electricity. Furthermore, for many, income to pay for electricity bills comes from the federal government. MKO noted that Aboriginal Affairs and Northern Development Canada (AANDC) funds electrical costs based on a cost reference manual and not based on actual costs. Of particular concern to MKO is the statistic that currently 86.3% of all Residential and General Service accounts in the MKO First Nations are in arrears, suggesting a significant existing issue with the ability of the MKO First Nations customers to pay the current electric rates. MKO cited several presenters who indicated in a presentation to the NFAT Panel that Manitoba Hydro will not deliver Power Smart programs to customers in arrears.

The MKO suggested that measures are required to mitigate the impact of rate increases on northern First Nations, including the establishment of objectives to make DSM programs available all First Nations customers. In that regard, the MKO sought a recommendation from the NFAT Panel that Manitoba Hydro be directed to regularly measure and report on the actual availability and penetration of Manitoba Hydro's lower income DSM programs to First Nation customers. No rate increase greater than the rate of inflation should apply to ratepayers in the MKO First Nations unless and until Manitoba Hydro or an independent DSM entity makes DSM and Power Smart universally accessible to all customers in the MKO First Nations, and universal penetration of these programs in the MKO First Nations can be confirmed.

The MKO also argued for several rate mitigation measures for MKO First Nations customers, submitting that while they currently pay the same level of rates as other customers, they do not share in the same level of provincial benefits as other ratepayers, with many of them having their income level determined by the Government of Canada. Furthermore, many of them could be classified as "Hydro Affected

Customers” since they reside in an area with significant existing hydro projects. MKO suggested six specific rate mitigation measures:

1. The removal of environmental mitigation costs from rates paid by Hydro Affected Customers, since these customers are directly affected by the environmental effects of the project;
2. An allocation of a greater share of net export revenue based on the recognition that a fundamental change in understanding has occurred since the time First Nations first entered into treaties and signed mitigation agreements, and the recognition that the generating stations located in the area are being used to create export revenue;
3. The creation of an “equivalent to gas” rate for the heat portion of the electricity bill, similarly to what is currently being provided to Manitoba Hydro employees working in the area, who pay a rate equivalent to the lowest average heating cost in Winnipeg. The MKO noted that natural gas service is not available to any of the MKO First Nations;
4. An allocation of net export revenue to reduce the cost of service in the four remaining Diesel communities that are not connected to the electric grid;
5. A removal of water rental fees from the bills of Hydro Affected Customers. In MKO's view, these represent an indirect provincial taxation from which First Nations should be exempt; and
6. The creation of a First Nation customer class, of which Hydro Affected Customers could be a sub-class.

Lastly, MKO noted that there is no reason why First Nations that have been affected by northern dams before the current benefit sharing model with the KCN was developed should not receive a portion of the benefits from past or current projects as well.

APPENDIX 7 Summary of Public Presentations

For the completeness of the record, this Appendix provides a summary public Presentations received by the Panel. The Panel regrets any errors or omissions that may have occurred in summarizing these Presentations. The full Presentations can be accessed at <http://www.pub.gov.mb.ca/nfat>.

Winnipeg Harvest

Donald Benham spoke to Winnipeg Harvest's perception on how Manitoba Hydro's plans are likely to affect lower income Manitobans. Mr. Benham noted Manitoba Hydro's current policy does not distinguish rates on ability to pay. It was also noted that the policy of cross-subsidization is already well-established in relation to urban-rural ratepayers. Based on this policy, rates are set to increase uniformly and lower income ratepayers are not able to absorb the increases. This results in more people taking money out of food budgets and greater reliance on food assistance from Winnipeg Harvest and its associated agencies.

Winnipeg Harvest then issued a proposal. The proposal recommends that the PUB raises rates by no more than one percent per year for lower income ratepayers. Ratepayers would apply to be designated as lower income ratepayers. Income levels for determining eligibility would be based on the 2012 Acceptable Living Level report. The Acceptable Living report produced by Winnipeg Harvest and the Social Planning Council of Winnipeg measures how much money is needed to buy basic necessities in Winnipeg.

It is also the position of Winnipeg Harvest that flooding and dams negatively affect the fishing, hunting and gathering of indigenous peoples in rural communities and their ability to provide their own food.

Bipole III Coalition

Dr. Garland Laliberte's presentation questioned Manitoba Hydro's load forecast upon which its preferred development plan relies. He stated that recent trends in both energy and peak load reveal a flattening of growth in Manitoba load that began in 2005/06, well before the 2008 recession. He further stated that this points to a similar flattening of demand in the region into which Manitoba seeks to export electricity and beyond. He proposed replacing Manitoba Hydro's load forecast with a moderate forecast that is more reflective of the trends outlined. The risk of proceeding with the preferred development is rates that escalate even more rapidly than projected. He raised the possibility of Manitoba Hydro becoming insolvent. He advocated a pause in the

implementation of any plan, a pause which would allow the utility to take advantage of the extended timeline that a more moderate load forecast would permit. Further, domestic load should be continually monitored, and there should be further reviews based on more credible load forecasts.

Manitoba Industrial Power Users Group

Mr. Bill Turner stated that the recent change in available lower-cost natural-gas-produced power in the U.S. is making it more difficult for some major Manitoba companies to be competitive in the export of finished goods. Given the relative importance of electricity to industry, both the actual price and the predictability of electrical costs are extremely important. The Manitoba Industrial Power Users Group asked the Board to take a long-term view and allow them to retain a competitive position in Manitoba and in North America. The Manitoba Industrial Power Users Group indicated the importance of its associated businesses to the Manitoba economy.

Mr. Turner stated that although the Manitoba Industrial Power Users Group is supportive of continuing hydro development, it has concerns with the current preferred development plan. Mr. Turner indicated that industrial users are eager participants in Demand Side Managements programs. The Manitoba Industrial Power Users Group supports expansion and exports to other markets by Manitoba Hydro, but not at the sake of loss of domestic power loads.

Mr. David Forsythe relayed further concerns industrial users have with the Preferred Development Plan, specifically with the risk borne by ratepayers. He indicated that if the assumptions of Manitoba Hydro are incorrect, ratepayers will face rapidly increasing costs, contrary to the interests of industrial users.

Interchurch Council on Hydropower

Mr. Will Braun provided the Board with concerns relating to the Preferred Development Plan. He indicated that the faltering of Wuskwatim is a key indicator of issues with the overall plan. Wuskwatim highlights the risk and unpredictability of Manitoba Hydro's forecasts. He further stated that the resulting rate increase cannot be afforded by residents of northern Manitoba. He also outlined a number of environmental issues associated with the project, including the macro environmental impacts of the Preferred Development Plan fuel source in relation to the Churchill River Diversion. In his opinion, Manitoba Hydro failed to properly consider Demand Side Management as an alternative to the Preferred Development Plan. He argued that this planning error is so fundamental it should stop the process.

Canadian Wind Energy Association

Mr. Tom Levy provided a letter that presented CanWEA's belief that wind energy will continue to make a valuable contribution to Manitoba's future electricity needs. Further, he stated that wind energy is increasingly cost-competitive, provides important economic benefits to rural communities and can serve as a valuable complement to hydroelectricity.

Elton Energy Co-operative

Mr. Dan Mazier submitted a letter highlighting considerations for future energy production. It stated that the cost per kWh of non-hydro renewable energy continues to be economically competitive compared to non-renewables and non-hydro renewable energy can serve as a valuable complement to hydroelectricity.

The Lake on the Pembina Committee

Mr. David Melvin appeared on behalf of The Lake on the Pembina Committee, which represents five rural municipal governments and numerous village and town councils in the Pembina valley area of southern Manitoba that is not currently served by natural gas. He suggested that there would be significant benefits to expand gas service to the area, as with the phase-out of coal, businesses and industry would have to switch to expensive hydroelectricity, while in southwestern Manitoba, gas is being flared off. He further suggested that southeastern Manitoba would be an excellent location for a gas generating plant, since existing transmission already exists in the area due to the St. Leon windfarm.

GEOptimize

Mr. Ed Lohrenz stated that the use of geothermal energy is a more cost-effective alternative to hydroelectricity. He further stated that geothermal energy is established and proven in Manitoba, and less expensive to implement than the proposed projects as well as better for the environment. In this analysis, he compared the energy projections associated with the Preferred Development Plan to possible production from increased geothermal development. He presented information showing the increasing use of geothermal energy in Canada and the United States, citing increased accessibility and improved installment training that reduce risk in implementation.

50 by 30

Mr. Daniel Lepp Friesen spoke to 50 by 30's proposed goal to increase Manitoba's renewable energy use from 30% to 50% by the year 2030. In implementing this plan, he

suggested utilizing renewable energy sources in combination with demand reduction programs. 50 by 30 would like to Panel to evaluate Manitoba Hydro's plan in the context of an overall energy policy in Manitoba, and suggests long-term, comprehensive planning prioritizing renewable energy sources.

Buller Center for Business

Mr. Bruce Duggan presented his concerns about Manitoba Hydro's Preferred Development Plan, in particular the capital expenditure forecast. He expressed concern with the debt financing approach the project would require and the fiscal stability of Manitoba Hydro and the province. He suggested delaying the project until Manitoba Hydro provides evidence that it has fully utilized Demand Side Management. He also suggested delaying the project until after Bipole III expenditures have peaked to reduce the pressure on Manitoba Hydro to raise debt.

Tim Sale

Mr. Sale expressed concern with Manitoba Hydro's Preferred Development Plan, and is of the opinion that the plan exposes Manitobans to unacceptable risks and major rate increases. He questioned Manitoba Hydro's past record of capital cost estimates. In his assessment he also considered the low cost of natural gas, the decreasing cost curve of alternative energy production methods, and unstable future interest rates. He advocated an assessment based on risk management. Mr. Sale believes Manitoba Hydro should prioritize its mandate to provide cost-effective power to Manitobans.

Prof. David G. Barber

Professor Barber of the Center for Earth Observation Science presented on climate change, including recent assessment reports, increasing global land-ocean temperatures, and reduction of sea ice caused by society's addiction to fossil fuels. He indicated that these changes could impact Manitoba infrastructure and agricultural crops and are already affecting the global economy through natural disasters. Professor Barber stated that climate change is a present issue that requires responsive planning.

Jackie Girardin

Ms. Girardin is concerned about electricity rate hikes proposed by Manitoba Hydro. She indicated that individuals who live in rural Manitoba only have the option of using electricity to heat their homes. She characterized the proposed rate increases as "outrageous" and states that increased electricity costs of this magnitude will put a significant financial strain on her and individuals in similar circumstances.

Ken Klassen

Mr. Klassen has over 30 years of experience focused on improving the energy and environmental performance of new and existing buildings and communities. He stated that the employment projections and comparisons of the Preferred Development Plan as compared to Demand Side Management are problematic. Mr. Klassen questioned the projected employment creation and the low number of permanent jobs created by the Preferred Plan. He indicated there were numerous employment advantages to using Demand Side Management.

Mr. Klassen indicated other benefits of using Demand Side Management. He stated energy efficiency was the lowest cost source of increased available electricity, and he believes that there has been a lack of consultation with local energy efficiency experts. He indicated there are a numerous energy efficiency measures that remain options.

Allan Ciekiewicz

Mr. Ciekiewicz presented his concerns with Manitoba Hydro's Preferred Development Plan, citing inaccuracies with its underlying predictions, projections and forecasts. He questioned the burden the Plan places on ratepayers for the purpose of supporting export markets. He questioned Manitoba Hydro's transparency. He argued that current production capabilities combined with Demand Side Management are sufficient to meet energy demands. He also addressed the possible risks associated with the Preferred Development Plan, specifically the possible repercussions of a severe drought. In addition, he questioned the planned rate increases in light of what he perceived to be Manitoba Hydro's excessive capital expenditures.

Dr. Peter Kulchyski

Dr. Kulchyski presented on hidden costs associated with the Keeyask and Conawapa projects. These hidden costs relate to potential aboriginal title and rights liabilities, and costs associated with continuing detrimental social impacts of these developments on local indigenous communities. He stated that outstanding or unfulfilled Treaty rights or claims can be considered contingent liabilities that have not been properly accounted for by Manitoba Hydro.

Dr. Kulchyski gave three examples of the liabilities potentially affecting the projects. They are a) the lack of signatures on Treaty 5 by Tataskweyak representatives; b) the non-surrender of water rights in Treaty 5; and c) the lack of constitutional amendments supporting the so-called implementation agreements associated with liabilities arising from obligations made in the Northern Flood Agreement. Dr. Kulchyski further stated

that problems associated with these agreements could lead to substantial claims by indigenous communities, the notion of which is reinforced by the Supreme Court's strong position on protecting Aboriginal and Treaty rights. He argued that Manitoba Hydro's development plans will only benefit the small professional class, and will not alleviate poverty in those communities but create further disparity.

Solange Garson, Carol Kobliski & Janie Duncan

Ms. Garson, Ms. Kobliski and Ms. Duncan all expressed concerns with the transparency and accountability of Manitoba Hydro's expenditures and relations with First Nations communities. They feel that Manitoba Hydro has not utilized funds appropriately, causing unnecessary expenses to be passed on to ratepayers and communities affected by hydro development. There was particular concern with expenses relating to legal and consulting costs spent in planning and negotiations. They are concerned that business entities meant to accumulate economic benefits for first nations communities have failed to do so. Ms. Duncan argued that the Preferred Development Plan should not go forward.

Lorna Kopelaw

Ms. Kopelaw advocated for the communities along routes 201, 202, 203 and 204. Ms. Kopelaw argued that Manitoba Hydro's plan was severely flawed. She stated the plan will damage the heritage of these communities, have negative financial impacts, damage the ecosystem, and threaten the health of these communities. In her opinion, the plan unfairly exploits these communities.

Pimicikamak Okimawin

Mr. David Muswaggon expressed his community's concerns regarding the development plan. Mr. Muswaggon expressed his people were not in support of Manitoba Hydro's project, both due to the escalating costs of hydroelectricity for consumers and the destruction of their homeland and heritage. He expressed the opinion that the current infrastructure is sufficient to support Manitoba's energy needs. He expressed concerns that the ecological and cultural costs have not been adequately addressed in energy development and planning. He encourages an assessment of the legality and fairness of the projects that reflects indigenous peoples as a sovereign indigenous nation with their own values and legal systems.

Mr. Darwin Paupanekis presented a historical background of the Pimicikamak people, including specifics about their historical lifestyle and connection to the land. Further, Mr. Paupanekis described the impact he believed continued development by Manitoba

Hydro would have on the land and lifestyles previously stated. His people do not believe Manitoba Hydro has properly considered the needs of northern Manitobans, and has failed to properly mitigate ongoing environmental concerns. In addition, he stated that the Province of Manitoba and Manitoba Hydro have failed to meet their obligations related to the Northern Flood Agreement and other Treaties.

Ms. Flora Jane Ross spoke to the difficulties faced in their community. She discussed problems with basic amenities, sickness, and education. To address these problems, she stated that it is important to be able to access and utilize their land for traditional purposes.

Mr. Mervin Garrick expressed his concern with the Province's history of compliance with the Northern Flood Agreement. He believes the spirit of the agreement has not been fulfilled. He cites issues relating to continued poverty, unemployment and environmental damage in his community.

Mr. Tommy Monias expressed his belief that Manitoba Hydro has utilized an imbalance in bargaining power in its relations with aboriginal people. He encouraged alternatives to hydroelectricity, such as biomass and wind.

Mr. George Ross expressed concern regarding the relationship between Pimicikamak and the Province. He highlighted differences observed between pre- and post-development of hydroelectric dams proximate to their community. He further expressed concern about high electricity rates.

Mr. Jeremy Ross presented his objection to development of new dams. In his opinion, the current electricity production is sufficient, and any further development is not worth the resulting difficulties faced by surrounding communities. He also objected to any increased rates for people in his community due to the increased financial strain that would result.

Mr. Darrell Settee expressed disapproval with Manitoba Hydro's projects in their entire form. He is concerned with the environmental and ecological impacts of the projects. He questions the value of the projects. He is also concerned with the loss of land with important cultural, traditional and spiritual significance.

Ms. Shelly Paupanekis spoke against any further hydro developments in the area, due the negative impacts they have on the land, waters, resources and recreation for those living in Cross Lake.

Mr. Jack Osborne objected to any further hydro developments at this point in time. He requests further consultation with First Nations people before further developments take place.

York Factory First Nation – Gordon Wastesicoot

Mr. Wastesicoot presented the views of York Factory First Nation in support of the Keeyask Project. The community heavily analyzed the benefits and costs of the project and decided in its favour. He further stated that the financial and employment benefits from the project would not otherwise be available, and he expressed hope that the project will improve the socio-economic conditions of the community. The community is optimistic that it can navigate any obstacles faced to reach a mutually satisfying result. Mr. Wastesicoot expressed concern with increasing rates and the financial strain faced by his community.

Gerhard Randel

Mr. Randel presented an alternative to bury Manitoba Hydro's overhead high voltage transmission lines. He suggested that burying the lines will have the benefit of reducing lost electricity in transmission due to electromagnetic fields. By failing to pursue this alternative, Mr. Randel argued that Manitoba Hydro has failed to follow its mandate to produce electricity in a cost-efficient way. He further stated that burying the transmission lines also reduces health, environmental and economic costs. He cited studies showing increased incidents of cancer resulting from living close to transmission lines. He also explored risks associated with maintaining overhead transmission lines.

Jason Cook

Mr. Cook presented his experience on the effects hydro development has had on traditional aboriginal lifestyles. He described the destruction of his homeland and the environment. He indicated that navigational waterways are no longer safe to travel. He requested that future plans include a full socio-economic analysis that includes the costs previously stated. He also requested that that resource development should be planned and implemented in a transparent, accountable and equitable manner.

Leona Massan

Ms. Massan expressed concern with the cost of hydroelectricity in Gillam, Manitoba, and its effect on the strained financial budget of its residents. She questioned the underutilization of northern residents in project employment. She also cited examples of environmental and ecological damages caused by hydroelectrically development in her community.

Manitoba Keewatinowi Okimakanak

Elder Flora Beardy expressed thoughts and concerns of the community of York Landing. She indicated that the proposed rate increases would result in hardship for many residents. She indicated the nature of how residents of northern communities address budgetary concerns to attempt to address their basic needs. She requested that Manitoba Hydro come to the community to inform and advise residents on Power Smart and low income programs to help reduce electricity bills.

Mr. Roger Ross spoke on behalf of the Manto Sipi Cree Nation, which is concerned about the potential impacts of proposed rate increases at approximately double the rate of inflation. He calls on Manitoba Hydro to do everything possible to reduce electricity bills paid by First Nations people. He further recommended that the qualification requirements for the Home Insulation Program should not exclude individuals in arrears on their electricity bills. He does not want increased electricity costs to result in a reduction in the level of community programs and services in northern Manitoba.

Mr. Michael Anderson reiterated the difficulty faced by the community in affording hydro bills. He also addressed the problem previously addressed in the qualifications for the Power Smart program. He argued that the inability of these individual to access the Power Smart program inhibits them from reducing or paying off those debts. He also argued that First Nations people affected by hydro developments should be provided a portion of the revenue generated by such developments, and articulates a number of related options. The recommendations by Mr. Anderson in the presentation session mirrored the closing submissions of MKO.

Fox Lake Cree Nation

Mr. Ralph Beardy presented the impacts of the Preferred Development Plan in Fox Lake from the perspective of a business owner. One major issue with local hydroelectric development in the town of Gillam is a greater demand for land, contrary to Fox Lake's plans, historical claims, treaty and aboriginal rights. He referenced Fox Lake's support of the Keeyask project. Fox Lake is hoping to reach a mutually beneficial agreement with Manitoba Hydro regarding Conawapa. He suggested that a future goal for the community should be to work with Manitoba Hydro and the provincial government to create opportunities in Fox Lake.

Mr. Conway Arthursen spoke to the need for Fox Lake's First Nations community to be allotted more reserve land in Gillam. The Fox Lake First Nation requested the support of Manitoba Hydro as a third party interest holder in attempting to obtain more reserve land.

Fawn Morales

Ms. Morales suggested the possibility of creating a lock port on the Nelson River to allow safer navigation by boat. She discussed the negative impacts the dam had on marine life on which her people have relied. She expressed concern with the reduction of boreal forests and the destruction of ecosystems due to hydro development.

Alberteene Spence

Ms. Spence stated that she did not support the Keeyask dam with the current management and projections. She is not in favour of the major risk the project places on Manitobans, in particular First Nations people in northern Manitoba. She supports further analysis on alternative forms of energy.

Tataskweyak First Nation

Elder Eunice Beardy expressed concerns about the damages related to dam development. In her opinion although Manitoba has consulted with first nations people on certain issues, they have failed to show commitment to those groups in the implementation stages. She is concerned the land and environment will deteriorate further in future generations.

Ms. Charlotte Wastesicoot stated her belief that Manitoba Hydro should focus on stakeholders within its mandate, mainly provide sufficient power for the people of Manitoba.

South Indian Lake

Ms. Shirley Ducharme presented on the socio-economic impacts of past hydroelectric developments on their community. She indicated that the biggest impact has been on the fishing and trapping industry. There have been few employment opportunities provided to individuals in impacted communities. Due to hydro development the community have been unable to pursue traditional activities. The compensation for these losses has not been sufficient.

Ms. Hilda Dysart and Leslie Dysart spoke to the environmental impact of hydro development and the resulting impact on traditional aboriginal lifestyles. The cost to First Nations communities in surrounding areas is not worth the addition of the new dams.

Nisichawayasihk Cree Nation

Mr. Marcel Moody disputed information brought forward by previous presenters regarding the implementation of the Northern Flood Agreement. He stated that the Northern Flood Agreement has had success in spurring economic development in his community. He further stated that certain critiques of the agreement and Manitoba Hydro were uninformed and inaccurate on the actual compensatory measures being implemented. In his opinion, the partnership between Manitoba Hydro and his community has been working.

Elders Jimmy Hunter-Spence and Joe Moose reiterated the working relationship the community has with Manitoba Hydro. They stated that the two parties have worked together to form a relationship established on mutual respect and trust.

APPENDIX 8 **Appearances**

Manitoba Hydro Witnesses

Scott Thomson, President & CEO, Manitoba Hydro

Load Forecasting Panel

Ed Wojczynski, Division Manager, Portfolio Projects Management, Manitoba Hydro
Lloyd Kuczek, Vice President, Customer Care & Energy Conservation, Manitoba Hydro
Lois Morrison, Division Manager, Consumer Marketing and Sales, Manitoba Hydro
Dale Friesen, Division Manager, Industrial & Commercial Solutions, Manitoba Hydro
Ian Page, Division Manager, Corporate Planning & Strategic Review, Manitoba Hydro
Ingrid Rohmund, Director, Energy Analysis and Planning, EnerNOC Inc.

Needs and Alternatives Panel

Joanne Flynn, Division Manager, Power Planning, Manitoba Hydro
Terry Miles, Manager, Resource Planning & Market Analysis Department, Manitoba Hydro
Bill Hamlin, Manager, Energy Policy & Analysis Department, Manitoba Hydro
David Cormie, Division Manager, Power Sales and Operations, Manitoba Hydro
Dave Bowen, Manager, Project Services Department, New Generation and Construction Division, Manitoba Hydro
David Jacobsen, Section Head, Interconnections & Grid Supply, Manitoba Hydro
Adam Borison, Director, Navigant Consulting Inc.
Dean Murphy, Principal, Brattle Group
Eric Swanson, Attorney, Winthrop & Weinstine, P.A.
Rene Roy, Director, Scientific Programme, Ouranos Consortium
Kristina Koenig, Hydrologic Studies Section Head, Water Resources Engineering Department, Manitoba Hydro

Finance Panel

Darren Rainkie, Vice President, Finance & Regulatory, Manitoba Hydro
Manfred Schulz, Corporate Treasurer, Manitoba Hydro
Liz Carriere, Manager, Financial Planning Department, Manitoba Hydro
Greg Barnlund, Division Manager, Rates & Regulatory Affairs, Manitoba Hydro

Socio-Economic Panel

Shawna Pachal, Division Manager, Power Projects Development Division, Manitoba Hydro

Jane Kidd-Hantscher, Partnership Implementation Supervisor, Manitoba Hydro

Marvin Shaffer, Consultant, Marvin Shaffer & Associates Ltd.

Karen Anderson, Director of Operations, Fox Lake Cree Nation Negotiations Office

Ted Bland, Senior Negotiator, York Factory Future Development

Norman Brandson, Consultant, N2B Environmental, Resource & Governance Consultancy and EarthWise Environmental Governance

Martina Saunders, Negotiator, York Factory Future Development

Victor Spence, Manager of Future Development, Tataskweyak Cree Nation

Independent Expert Consultants

Robert Sinclair, Vice President, Potomac Economics, Ltd.

David Patton, President, Potomac Economics, Ltd.

John Todd, President, Elenchus Research Associates

Russ Houldin, Associate, Elenchus Research Associates

Craig Sabine, Senior Manager, Energy and Utilities, MNP

Sarah Keyes, Consultant, Energy and Utilities, MNP

Dan Peaco, President, La Capra Associates

John Athas, Principal Consultant and Treasurer, La Capra Associates

Mary Neal, Consultant, La Capra Associates

Glenn Davidson, Senior Project Manager, Power Engineers

Brian Furumasu, Senior Project Manager, Power Engineers

Paul Arnold, Senior Project Manager, Power Engineers

Michael Robertson, Specialist Engineer and Project Manager, Knight Piésold

Boris Fichot, Senior Engineer, Knight Piésold

Russell Tyson, President, TyPlan

Pelino Colaiacovo, Managing Director, Morrison Park Advisors

Benjamin Kinder, Vice President, Morrison Park Advisors

Intervener Panels

Affordability Panel

Gio Robson, Certified Energy Advisor and President, prairieHOUSE Performance Inc.

Gloria Hartley

Dave Mouland

Albertine Mason

Jacqueline Salamisan
Darrell Settee
Richard Genaille

Elders and Traditional Land Users

Noah Massan
Robert Spence
Flora Beardy
Ila Disbrowe
Christine Massan
Jack Massan
Ivan Moose

Intervener Experts

Phillipe Dunskey, President, Dunskey Consulting Inc.
William Harper, Associate, Econalysis Consulting Services
Douglas Gotham, Director, State Utility Forecasting Group, Purdue University
Wayne Simpson, Head, Department of Economics, University of Manitoba
Harvey Stevens, Consultant
Melanie O'Gorman, Associate Professor, Department of Economics, University of Winnipeg
Jerry Buckland, Professor of International Development Studies and Dean, Menno Simons College
Marla Orenstein, Senior Partner, Habitat Health Impact Consulting
Kyrke Gaudreau, Sustainability Manager, University of Northern British Columbia
Robert Gibson, Professor and Associate Chair, Department of Environment and Resource Studies, University of Waterloo
Jill Gunn, Assistant Professor, Department of Geography and Planning, University of Saskatchewan
Roger Higgin, Principal, Sustainable Planning Associates Inc.
Paul Chernick, President, Resource Insight, Inc.
Wesley Stevens, Senior Associate, Power Advisory LLC
Patrick Bowman, Principal and Consultant, InterGroup Consultants, Ltd.
Rick Hendricks, Director, Camerado Energy Consulting Inc.
Whitfield Russell, President and Partner, Whitfield Russell Associates
Geneva Looker, Senior Associate, Whitfield Russell Associates

Legal Counsel and Representatives

Patti Ramage, Counsel, Manitoba Hydro
Marla Boyd, Counsel, Manitoba Hydro
Doug Bedford, Counsel, Manitoba Hydro
Helga Van Iderstine, Counsel, Manitoba Hydro
Jennifer Moroz, Counsel, Manitoba Hydro
Odette Fernandes, Counsel, Manitoba Hydro
Janet Mayor, Counsel, Manitoba Hydro
Jack London, Counsel, Keeyask Cree Nations Partners
Brad Regehr, Counsel, Keeyask Cree Nations Partners
Byron Williams, Counsel, CAC
Meghan Menzies, Counsel, CAC
Aimée Craft, Counsel, CAC
Joëlle Pastora Sala, CAC
William Gange, Counsel, GAC
Peter Miller, Advisor, GAC
Antoine Hacault, Counsel, MIPUG
George Orle, Counsel, MKO
Michael Anderson, Advisor, MKO
Jessica Saunders, Counsel, MMF
Corey Shefman, Counsel, MMF
Tony Marques, Counsel, MMF
Christian Monnin, Counsel, Independent Expert Consultants
Michael Weinstein, Counsel, Independent Expert Consultants
Bob Peters, Public Utilities Board Counsel, Fillmore Riley LLP
Sven Hombach, Public Utilities Board Counsel, Fillmore Riley LLP

Public Utilities Board Staff and Advisors

Hollis Singh, Executive Director, Public Utilities Board
Kurt Simonsen, Associate Secretary, Public Utilities Board
Josée Lemoine, Project Manager, NFAT Review, Public Utilities Board
Margaret Smith, Public Utilities Board Advisor
Bill Smith, Public Utilities Board Advisor
Brenda Bresch, Office Manager, Public Utilities Board
Nancy-Ann Cribbs, Administrative Assistant to the Public Utilities Board
Diana Villegas, Administrative Assistant to the Public Utilities Board
Larry Buhr, Public Utilities Board Advisor
Roger Cathcart, Public Utilities Board Advisor
Brady Ryall, Public Utilities Board Advisor

APPENDIX 9 Glossary of Terms

2x16 Power: Power delivered two days a week (during weekends) for 16 hours per day, from 6:00am to 11:00pm.

5x16 Power: Power delivered five days a week (during weekdays) for 16 hours per day, from 6:00am to 11:00pm.

Alternating current (AC): Electric current that reverses its direction of flow at regular intervals. This occurs 60 times each second and is referred to as a frequency of 60 cycle (Hertz). All utilities in North America use 60 Hertz.

Average Energy: The energy Manitoba Hydro can produce in any given year based on average water flows.

Base Load: The basic demand for electricity that is expected during all times.

Bilateral Contract: A contractual agreement between two market participants for the purchase or sale of capacity and/or energy.

Board Counsel: Legal counsel to the Public Utilities Board, who acted as counsel to the NFAT Panel.

Canadian Environmental Assessment Agency: The federal Canadian environmental assessment body.

Capacity: The amount of power that a piece of equipment, or a group of pieces of equipment acting together, can generate or transmit. For example, a transmission line may have a transfer capacity of 750 megawatts or a generating station may have a capacity to produce 1200 megawatts.

Carbon Price: A tax or surcharge levied by the government on electricity generated from sources that emit carbon dioxide (CO₂). The carbon price is specified in dollars per tonne of CO₂. Different generating stations produce different amounts of carbon dioxide per MWh of electricity output, with coal producing the greatest amount of CO₂ and combined cycle gas turbines producing about half of the emissions of coal per MWh.

Clean Environment Commission (CEC): Manitoba's environmental regulatory tribunal.

Combined Cycle Gas Turbine (CCGT): The combination of a gas turbine and a steam turbine in an electric generating plant. The waste heat from the gas turbine provides the heat energy for the steam turbine.

Conawapa Generating Station: A proposed new hydroelectric generating station with a capacity of 1,485 MW, producing 4,650 GWh of dependable energy per year and an average of 7,000 GWh per year.

Consumers' Association of Canada (Manitoba) Inc. (CAC): One of the five Interveners in the NFAT Review.

Congestion: Congestion occurs when there is inadequate transmission to deliver all of the lowest-cost power to the load.

Contingency or Operating Reserves: Available spare generation that must be kept available in the event of sudden generation or transmission outages.

Curtailed Load: A DSM load reduction program in which customers agree to a partial or complete power shut off for a limited period of time in exchange for lower electricity rates.

Demand Side Management (DSM): A targeted reduction in the demand for electricity through energy efficiency measures and updated codes and standards. DSM can reduce the requirement for new electricity generation and serve as a source of meeting demand in the same manner as new generation. Manitoba Hydro administers DSM through its Power Smart plan.

Dependable Energy: The energy that a generation station or electric system can produce under the lowest water flow conditions. Manitoba Hydro's total dependable energy is comprised of dependable energy from hydro generation, thermal generation, wind generation, and imports.

Discount Rate: A percentage rate by which a future revenue flow is discounted to derive the Net Present Value (NPV) of that flow of money.

Distributed Generation: Electricity generation located throughout the electrical distribution system, usually closer to load centres or downstream of the customer's meter. Distributed generation is usually comprised of smaller-scale generating facilities.

Diversity Agreements or Diversity Exchanges: Agreements that provide for the seasonal exchange of power between utilities during their respective peak load periods. When utilities have opposite peak load seasons, they can enter into diversity agreements to exchange power. For example, Manitoba's peak power load is in the winter, while Minnesota's peak power load is in the summer.

Energy: A quantity of power consumed over a period of time. Energy is expressed in kilowatt-hours (kWh), megawatt-hours (MWh) or gigawatt-hours (GWh). A 100-watt incandescent light bulb burning for 10 hours consumes one kWh (0.1 kW x 10 hrs).

Energy Information Agency (EIA): Part of the U.S. Department of Energy, the EIA creates forecasts for electricity and natural gas consumption, market prices, and supplies that are used by the electricity industry.

Expected Value: The probability-weighted NPV of the development plans calculated from the low, reference, and high estimates of energy prices, capital costs, and economic indicators/discount rates. Expected value is used in the economic analysis.

Firm Export: The guaranteed sale of a contracted amount of energy and/or capacity to utilities or customers located outside of Manitoba.

Firm Power: Capacity and energy that must be supplied to meet domestic demand or under certain export contracts. Firm power is guaranteed to be available when specified and can only be interrupted in emergencies or when the reliability of the power system is threatened.

Firm Transmission Service: Full path transmission service that has the highest priority and cannot be interrupted unless all lower priority levels of service have been interrupted.

Fracking or Hydraulic Fracturing: A technique for drilling and completing natural gas wells that, combined with horizontal drilling, produces greater amounts of gas from an individual well. Fracking has significantly increased the North American supply of natural gas.

Fuel Switching: The switch from one heating fuel source to another (e.g., gas to electricity or electricity to gas).

GHG: See Greenhouse Gas.

Gigawatt-Hour (GWh): A unit of electrical energy. A GWh is the amount of electrical energy produced by one gigawatt of power applied over one hour of time, or 1000 MW over one hour.

Green Action Centre (GAC): One of the five Interveners in the NFAT Review.

Greenhouse Gases (GHG): Gases that contribute to climate change because of they contribute to the greenhouse effect of the Earth's atmosphere by trapping thermal

radiation from the sun. For electricity generation, the most common greenhouse gas - and the one of greatest concern - is carbon dioxide, which is a product of the combustion of fossil fuels such as coal and natural gas.

Grid Parity: The point where distributed generation technologies such as solar photovoltaics can generate electricity for the same cost as buying electricity from the utility using its distribution grid.

Gross Firm Energy: The total annual non-curtable demand for energy in Manitoba.

Gross Total Peak: The highest demand for power to be expected in Manitoba in any specific year, measured at generation as opposed to at the meter. It typically occurs during the coldest winter day.

Hydraulic Fracturing: See Fracking.

Independent Export Consultant (IEC): Independent third-party experts retained by the NFAT Panel for purposes of the NFAT Review. IECs were represented by independent legal counsel and subject to cross-examination of their reports and testimony.

Integrated Financial Forecast (IFF): A 10- or 20-year financial forecast prepared by Manitoba Hydro on an annual basis that details expected revenues, expenses, financial ratios and rate increases.

Intervener: An organization with interest in the NFAT Review that was granted legal standing to appear and adduce evidence, cross-examine witnesses, and make closing submissions. The NFAT Panel granted Intervener status to five parties pursuant to the Public Utilities Board's Rules of Practice and Procedure.

Interconnections: Power lines that interconnect one electrical utility's power system with another. Interconnections facilitate the export and import of power.

Interruptible Energy: A supply of energy, which is subject to short- or long-term interruption with or without notice.

Keeyask General Civil Contract: The contract Manitoba Hydro awarded to construct the majority of the Keeyask generating station, including the rock excavation and concrete works.

Keeyask Generating Station: A proposed new hydroelectric generating station with a capacity of 695 MW, producing annual dependable energy of 3,000 GWh and average

annual energy of 4,400 GWh. Manitoba Hydro plans to have Keeyask constructed for a 2019 in-service date.

Kilowatt (kW): The unit of electrical power equivalent to 1000 watts (W).

Kilowatt-Hour (kWh): A unit by which electrical energy is measured. A kilowatt-hour is a unit of energy equivalent to one kilowatt (1000 watts) of power applied over one hour of time. For example, 10, 100 W light bulbs switched on for one hour would use one kilowatt-hour (1000 W one hour). The electrical energy used in homes and small businesses is usually measured in kilowatt-hours.

LCOE: See Levelized Cost of Energy.

Levelized Cost of Energy (LCOE): The cost of constructing and operating a generating resource over its life, including capital cost, fuel cost, and operations and maintenance cost.

Load: The total amount of demand electricity.

Load Serving Utility: an electric utility that supplies electricity to end use customers. Manitoba Hydro, Minnesota Power, and Wisconsin Public Service are all load serving utilities.

Locational Marginal Price (LMP): The MISO market price for energy at a certain location, taking into account transmission losses and congestion effects that depress the price from the System Marginal Price.

Long-Term Firm Exports: The sale of electricity to parties outside Manitoba where the quantity and price of the electricity are fixed over a long-term period.

Manitoba Industrial Power Users Group (MIPUG): One of the five Interveners in the NFAT Review.

Manitoba Keewatinowi Okimakanak Inc. (MKO): One of the five Interveners in the NFAT Review.

Manitoba Métis Federation (MMF): One of the five Interveners in the NFAT Review.

Megawatt (MW): The unit of electrical power equivalent to 1,000,000 watts (W).

Megawatt -Hour (MWh): A unit by which electrical energy is measured. One MWh is a unit of energy equivalent to one million watts of power applied over one hour of time.

Midcontinent Independent System Operator, Inc. (MISO): MISO is a U.S.-based independent, not-for-profit regional transmission organization responsible for maintaining reliable transmission of power in 15 U.S. states and the Canadian province of Manitoba.

Minnesota Public Utilities Commission (MPUC): A regulatory body responsible for the regulation of natural gas and electric utilities in the state of Minnesota. MPUC has oversight over and approves the construction of natural gas and electricity facilities such as electric power plants, transmission lines, wind power generation plants, and large natural gas and petroleum pipelines. Manitoba Hydro's interconnection with the U.S. requires MPUC approval.

MISO: See Midcontinent Independent System Operator, Inc.

MPUC: See Minnesota Public Utilities Commission.

Net Present Value (NPV): The present value of a future revenue and cost stream. NPV is calculated by taking an assumed revenue in each future year and applying a discount rate to account for the time value of money (e.g., \$100 ten years from now do not have the same value as \$100 today). The applicable discount rate is a matter of judgment and was a subject of debate in the NFAT. Frequently in the NFAT the NPV of development plans is referenced to the NPV of the All Gas plan (i.e. the All Gas plan NPV is set to zero and the NPVs of the other plans are adjusted accordingly)

Nominal Dollars: Future year dollars that include the effect of inflation (CPI increases) as opposed to real dollars which have the effects of inflation removed.

Off-Peak Period: The overnight and weekend hours in a week during which load is usually lower than the average weekly load. Overnight the hours are 5 weekdays x 8 hours/day plus weekends which are 2 days x 24 hours/day.

On-Peak Period: The weekday daytime hours during which load is usually highest: from 6:00 am to 11:00 pm, otherwise known as “5x16.”

Opportunity Energy: Available surplus energy that Manitoba Hydro sells into the MISO market at the prevailing spot market price, and for which it has not negotiated firm pricing arrangements through a bi-lateral contract.

Peak Load: Instantaneous maximum amount of electricity used. On an annual basis, peak load in MISO occurs during the summer air conditioning season, while peak load

in Manitoba occurs during the winter heating season. On a daily basis, peak load varies with the business cycle.

Person-Year: A person-year of employment is the equivalent of one full time job for one year. The number of hours assigned to a person-year vary. In the Keeyask environmental impact assessment, one person-year of employment is defined as 3,000 hours of work.⁵⁰⁸

Power: The flow of electricity at any given time. Power is expressed in watts (W), kilowatts (kW – 1,000 watts) or megawatts (MW – one million watts).

Real Dollars: Future year dollars that have the effects of inflation removed, as opposed to nominal dollars which include inflation effects.

Simple Cycle Gas Turbine (SCGT): A turbine powered by natural gas or fuel oil in an electric generation plant. The waste heat from the gas turbine is exhausted and not utilized.

Solar Photovoltaic Generation: The conversion of sunlight directly into electricity by incidence of sunlight on a semiconductor surface, also known as a solar panel. The amount of electricity generated is proportional to the size of the solar panel, and can range from roof-top units that generate electricity for a residential home to utility-scale arrays of solar panels that produce megawatts of electricity.

Surplus Energy: Energy not needed to meet Manitoba demand and which Manitoba Hydro is not contractually required to export.

System Marginal Price (SMP): The system-wide MISO market price for energy. SMPs do not take into losses or congestion that can depress the market prices at specific locations.

System Participation Sale: In the context of Manitoba Hydro, a contract through which Manitoba Hydro sells a defined amount of energy, from a defined portion of its installed generating capacity, to a named contractual counterparty. System Participation Sales do not include any generation reserve as required by counterparty's operating authority.

Terms of Reference: The terms of the Panel's mandate to conduct the NFAT Review, including definitions of items that are and are not in scope. The Terms of Reference were approved by Order in Council 128/2013 on April 17, 2013.

⁵⁰⁸ Transcript, p. 3898.

Voltage: The electric potential between two points in an electric connection, expressed in volts (V) or kilovolts (kV). A North American electrical outlet operates at 120 volts. High-voltage transmission usually operates at either 230 kV or 500 kV.

Water Flow: The flow of water through Manitoba Hydro's hydraulic basins and generating stations. It is expressed in cubic metres per second (m³/s).

Watt (W): The unit of measurement of electrical power.