MANITOBA PUBLIC UTILITIES BOARD
NFAT REVIEW OF KEEYASK AND CONAWAPA GS



KNIGHT PIESOLD INDEPENDENT EXPERT CONSULTANT REPORT (REDACTED)

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VA103-449/1-1
Rev 1
January 23, 2014

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Rev	Description	Date	Approved
A	Issued to the PUB in Draft form for review by MH for confidential material and factual inaccuracies	January 13, 2014	MJR
0	Issued to PUB (Redacted Report)	January 17, 2014	KDE
1	Issued to PUB (Redacted Report) Revised Table 8.1	January 23, 2014	SRM

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EXECUTIVE SUMMARY

Overview

Through the intermediary of the Manitoba Public Utilities Board (PUB), the Government of Manitoba is carrying out a public Needs For and Alternatives To (NFAT) review and assessment of Manitoba Hydro's (Hydro's) Proposed Development Plan (Plan) for the Keeyask and Conawapa Generating Stations (GSs) and their associated transmission facilities.

The PUB has engaged Knight Piésold Ltd. (KP) as an Independent Expert Consultant (IEC) to review the construction management and capital and operating costs for select resource options.

The following summarizes the KP findings as they correspond to the scope of work provided by the PUB on September 2, 2013:

Item 1: Capital and Operation and Maintenance Cost Estimates for Conawapa and Keeyask GS

KP has reviewed and assessed Hydro's Capital and Operation and Maintenance (O&M) cost estimates for the Conawapa and Keeyask Generating Stations. KP reviewed documentation and procedures provided by Hydro and held teleconference discussions with their New Generation Construction Division (NGCD) and found that the approach and methodologies used by Hydro are consistent with industry best practices. The resulting direct "overnight" capital costs are well documented and within the order of magnitude expected for the proposed developments. For both facilities the direct capital costs make up approximately 2/3 of the total cost.

KP found that the amount of contingency carried for the two generation projects could be considered insufficient depending on the use made of the capital cost estimates. The capital cost estimate probability distribution curves developed by Hydro can be readily used to calculate the appropriate contingency associated with the decision making context. Hydro have chosen a P50 estimate for their Base Costs but there are others who recommend a higher estimate to provide an adequate contingency for such large individual projects.

Given the described high likelihood of labour shortages the management reserve associated with labour is anticipated and therefore would likely be better included in the contingency. Furthermore the labour reserve apparently only address particular elements (not fully disclosed) and not a complete general labour shortage or a lack of productivity similar to that encountered at Wuskwatim.

Since the management reserve for escalation is indexed to a more aggregate blended escalation factor than CPI, this portion is also somewhat anticipated and could also therefore be integrated more directly into the cost estimate. Overall, the planned use of management reserves appears to be more appropriate for the Conawapa GS than for the Keeyask GS, mainly because it is further down the line and is presently not as well developed.

Anticipated Operation and Maintenance costs are deemed to be within industry norms and are documented.

The December 2013 Civil Contract Bid submissions will have a significant repercussion on the overall cost estimate and warrant being considered as part of the NFAT process. They should confirm not only the cost estimates, but also validate many of the assumptions surrounding the project execution strategy.

Item 2: Construction Indirect Costs for Conawapa and Keeyask GS

KP has reviewed and assessed Hydro's indirect cost estimates for the Conawapa and Keeyask Generating Station Projects (KGSP and CGSP). Generally the indirect costs are thought to be quite high, but not dissimilar to other Crown Corporations, and much of the overhead cost is related to the chosen contracting method and the remote location. The indirect costs were not documented with the same diligence as the direct cost estimate, perhaps in part because they were developed internally whereas the consulting design engineers provided most of the input to the direct cost estimates. KP would have liked to see more Hydro documentation of the indirect costs.

KP has also reviewed and assessed the information made available on the Keeyask Infrastructure Project (KIP). Given the advanced stage of this project (with many projects presently underway and many others already procured), the resulting capital costs should be considered a higher class of estimate and be considered more accurate. As the KIP has a more advanced level of project definition and is also a defined (lost) investment risk it should be presented on its own merits, separate from the KGSP.

Item 3: Construction Management, Schedule, and Contracting Plans for Conawapa and Keeyask GS

KP has reviewed select material construction management, schedule, and contracting plans for Conawapa GS and Keeyask GS. The overall approach follows well documented internal standards developed by Hydro's NGCD. The contracting method varies by project component but the principal civil works contracting strategy is an Early Contractor Involvement (ECI) Project Delivery Strategy.

Overall the project delivery strategy has been to transfer risk away from Contractors and to Hydro in order to better understand and share the risks and obtain a better contract price as a result. As a result, Hydro will bear the arduous task of managing and coordinating the integration to ensure compliance with their own internal standards. It is difficult to ascertain how much work this integration will take as well as if Hydro has adequate internal capabilities. Going to outside project management firms or engineering firms for this would add additional costs.

Again, the December 2013 Civil Contract Bid submissions warrant being considered as part of the NFAT process, as they should confirm the project execution strategy including the construction management, schedule and contracting plans.

Item 4: Capital and Operation and Maintenance Cost Estimates for Wind, Natural Gas Combined Cycle Gas Turbines, and Solar Facilities

KP reviewed the capital and O&M costs assumed by Hydro for wind, natural gas combined cycle gas turbines, and solar facilities. In contrast to the Keeyask and Conawapa hydro generating facilities, the wind, gas and solar facilities are at earlier stages of development, so less detail has been provided in preparation of the cost estimates. KP assessed the costs assumed by Hydro by reviewing recent industry assessments of project costs. This method of cost assessment is considered by KP to be valid for estimating costs for planning purposes.

For the wind projects, the costs were found to be valid for the time period in which the independent consultant's study was written (2010), but wind project costs have reduced in the interim and are expected to reduce further in the immediate future. As a result, KP believes that the NFAT assessment should incorporate more up to date cost estimates. The quoted anticipated O&M cost for wind projects is deemed appropriate, but would benefit from some sensitivity analyses.

For the natural gas project costs, appropriate cost estimates have been adopted for the combined cycle and industrial style simple cycle gas turbines (excluding transmission line and pipeline costs). Similar to wind project costs, the small reported range of natural gas project costs and the relatively lower uncertainty in project definition as compared with hydropower projects at a similar stage of development justifies KP's assessment. Again, the estimates would benefit from some sensitivity analyses.

The assumed capital costs for solar photovoltaic (PV) projects are deemed reasonable, but are subject to rapid change.

Item 5: Construction Management Plans, Schedule and Contracting Methods for Wind, Natural Gas Combined Cycle Gas Turbines and Solar Facilities

Very little to no information was developed or documented by Hydro concerning the construction management, schedule, or contracting plans associated with the planning stage wind, natural gas combined cycle gas turbines, and solar facility options.

Hydro have indicated an expected development and construction timeframe of approximately 3-5 years for a 65 MW wind project, 3-5 years for a natural gas facility and 3 years for a 20 MW solar power facility. The assumed development timelines for wind, gas and solar facilities are considered reasonable for the current level of definition for these facilities. More detailed development schedules and plans should be developed before these facilities are progressed further.

Items 6: Factors that Lead to Cost Increases over Successive Capital Expenditure Forecasts

Generally there has been a very consistent observation in Canada from coast to coast that hydropower is now being developed and engineered in a more rigorous way than in the past and that these projects are being subject to much increased environmental scrutiny. There have also been a decrease in the skilled labour pool and a significant increase in the number of competing projects in Northern Canada. Hydro and their engineering consultants have examined the causes behind the increases from year to year and have made a realistic appreciation of current trends in their cost estimating processes.

Item 7: Historical perspective of Construction Costs of Other Lower Nelson River GS

To the extent possible KP reviewed the information available. There have been significant material changes in the approach to large hydroelectric development since the construction of Limestone (1990), Long Spruce (1979), and Kettle (1974). The costs of the respective projects have been escalated and put in perspective.

Knight Piésold concurs with Hydro's statement that the cost of hydropower development in the past cannot be readily compared with the present and anticipated future.

Item 8: Justification for Increasing Direct and Indirect Costs

Overall, it is thought that Hydro is justified in increasing direct and indirect costs with respect to labour productivity and shortages, competition with other large civil projects in Canada, remote location, and northern and First Nation jobs as these difficulties have been evident over the past few years.

Item 9: High Level Assessment of the Construction Planning and Management of Construction Costs of Preferred Development Plan

At a high level, KP believes that the construction planning and management of the construction costs associated with Hydro's preferred development plan have been done in an appropriately detailed and professional manner. It is clear that much effort has been expended and continues to be expended by Hydro in an effort to ensure the successful development of the projects. KP does have reservations about some of the details, in particular some parts of the cost estimate process and the final results but these should largely be reconciled once the civil tender costs are known and the extra scope that has been assigned to KP is fulfilled.

The experience gained from the Wuskwatim project does not appear to have significantly changed the planning or contracting methodology used by Hydro, though there is evidence that the "lessons learned" have to a certain extent been incorporated in the final cost estimates. The cost estimate rates however do not incorporate the actual Wuskwatim productivity rates and Hydro has made the general assumption that labour conditions will not be as bad during the construction of Keeyask and Conawapa because they plan to offer better labour conditions.

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ABBREVIATIONS

AACE(I)....................Association for the Advancement of Cost Engineering (International)
BNA....................Burntwood Nelson Agreement
CCCT....................Combined Cycle Combustion Turbine
CCGT....................Combined Cycle Gas Turbine
CRC....................Cost Reimbursable Contract
DB....................Design Build
DBB....................Design Bid Build
ECI....................Early Contractor Involvement
EIS....................Environmental Impact Statement
EPCM....................Engineering, Procurement and Construction Management
FLCN....................Fox Lake Cree Nation
GCC....................General Civil Contract
GS....................Generating Station
IDB....................Integrated Design Build
IEC....................Independent Expert Consultant
IFF....................Integrated Financial Forecast
KCN....................Keeyask Cree Nation
KHLP....................Keeyask Hydropower Limited Partnership
KIP....................Keeyask Infrastructure Project
KGSP....................Keeyask Generating Station Project
NFAT....................Needs For and Alternatives To
NGCD....................Manitoba Hydro New Generation Construction Division
O&M....................Operations and Maintenance
Plan or PDP....................Proposed (or Preferred) Development Plan
PDS....................Project Delivery Strategy
PUB....................Manitoba Public Utilities Board
RP....................Recommended Practice (AACE International)
TCN....................Tataskweyak Cree Nation
TCSM....................Total Cost and Schedule Management
WLFN....................War Lake First Nation
YFFN....................York Factory First Nation

1 – INTRODUCTION

1.1 PURPOSE OF REPORT

1.1.1 Mandate

Through the intermediary of the Manitoba Public Utilities Board (PUB), the Government of Manitoba is carrying out a public Needs For and Alternatives to (NFAT) review and assessment of Manitoba Hydro's (MH's or Hydro's) Proposed Development Plan (Plan) for the Keeyask and Conawapa Generating Stations and their associated transmission facilities. The Terms of Reference for the NFAT review are attached in Appendix A and the location of the two projects is shown in Figure 1.1.

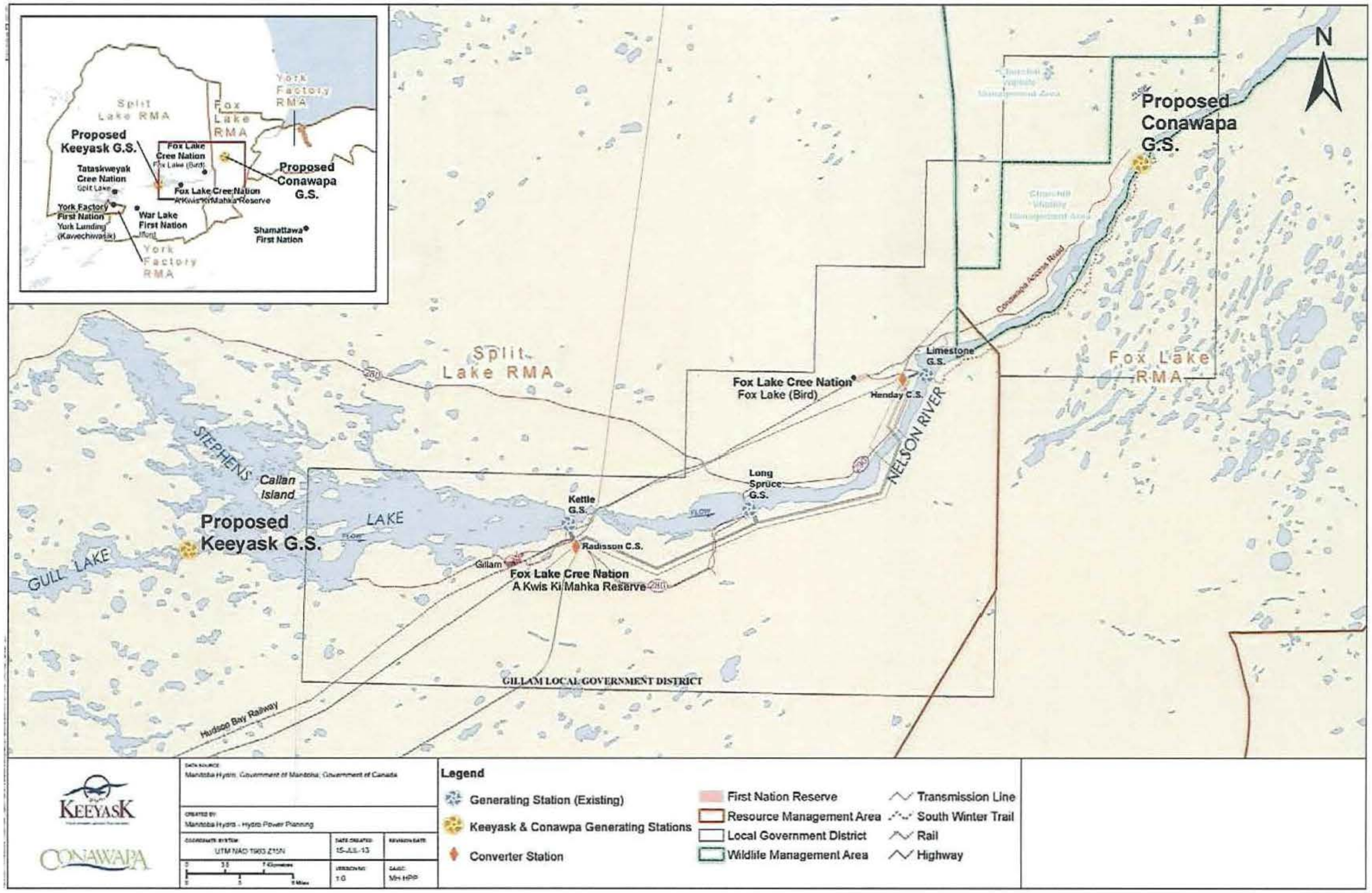
1.1.2 Independent Expert Responsibilities

The NFAT review and assessment has been undertaken by a number of Independent Expert Consultants (IECs), appointed by the PUB in accordance with their individual expertise. As one of the IECs, Knight Piésold Ltd. (KP) is responsible for the review and assessment of Hydro's construction management and cost estimates, as defined in the scope of work provided by the PUB on September 2, 2013 and attached as Appendix B. The report summarizes KP findings on the submissions filed by Hydro, the responses to Information Requests (IRs, both Confidential and Public) to Hydro, and other information deemed relevant to demonstrating to the PUB that the review was conducted with due diligence. The report makes recommendations but does not draw conclusions as to the needs for or alternatives to the Plan. This report will be filed as evidence on public record and KP will appear as a witness during the planned NFAT hearing.

1.1.3 About Knight Piésold Ltd.

Knight Piésold Ltd. is an employee-owned company, comprising consulting engineers, scientists, and technicians who provide engineering and environmental services. Founded in South Africa in 1921, Knight Piésold employs more than 850 staff in 30 offices located in 15 countries. Although each of these offices is integrated within Knight Piésold's global network, the company is committed to having a local presence. As such, each country office is set up as a local operating company that is run by local management, providing local employment and training. Knight Piésold has two Canadian offices, with a combined staff of over 200: one in Vancouver, BC and the other in North Bay, Ontario. This assignment has been undertaken by the Vancouver office.

Knight Piésold provides engineering and environmental services to the power, water resources, transportation, and construction sectors, among others. Knight Piésold has extensive experience with hydropower projects. Their accumulated experience covers a wide variety of designs, including installed capacities from 750 kW to 3,000 MW; surface and underground powerhouses; reservoirs; pumped storage; and run-of-river projects; and heads from 3 m to over 750 m.



NOTE:
(Source: MH NFAT Submission Map 2.1)

Figure 1.1 Location of Keeyask and Conawapa Projects

1.2 THE PREFERRED DEVELOPMENT PLAN

1.2.1 Intent

Hydro's Plan is envisioned to meet the growing provincial demand for electricity and make the most of opportunities to export power to US utilities. Hydro has stated that its Plan is being brought forward now to take advantage of the proposed Canada-USA interconnection and uncommon long-term firm export sale opportunities. 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 states that the Plan will provide important benefits to Manitobans and is reasonable concerning inherent uncertainties that exist over a reasonable range of future possible business cases, and that it is the best development option when compared to alternatives.

For more details on Manitoba Hydro's (Hydro's) governance and planning processes, KP was referred to a presentation to the PUB workshop dated May 31, 2010. To provide some context Hydro's system is composed of:

- 5,700 MW of Installed Capacity
- $14 Billion in Assets
- One-Third of revenues come from exports
- 548,000 electrical customers
- 267,000 natural gas customers, and
- 98% of energy is hydroelectric.

1.2.2 Manitoba Resource Options

Hydro utilised a staged screening process, which included evaluations of technical, environmental, socio-economic and economic characteristics, to hone in on the preferred resource supply options to meet its mandate. The contenders consisted of technologies suitable for utility-scale generation, including Demand Side Management (DSM, Power Smart), imports, wind, solar, biomass and natural gas, as well as hydro. Based on these evaluations certain resources such as solar, nuclear, coal and biomass were screened out.

Specific resource options were selected at the conclusion of the screening as suitable candidates to be included within individual development plans mainly because of their cost competitiveness and environmental attractiveness:

- Additional DSM
- Keeyask GS
- Conawapa GS
- Combined-Cycle natural Gas Turbines (CCGT), Simple-Cycle natural Gas Turbines (SCGT), and
- Wind Farms.

Hydro's Forecast and Recommendations

- Growth at 1.6% per year projected for next 20 years (including Demand Side Management)
- Need more power by 2023, and

- Preferred Development Plan includes the construction of 695 MW Keeyask and 1,485 MW Conawapa Generating Stations

1.2.3 Proposed Preferred Development Plan

Hydro's Preferred Development Plan includes the construction of the Conawapa and Keeyask Generating Stations on the Nelson River in northern Manitoba and the necessary domestic AC transmission lines.

Some of the details of the Preferred Development Plan are as follows:

- Keeyask Generating Station (KGS), 695 megawatts (MW), In-Service Date (ISD) of 2019
- Conawapa Generating Station (CGS), 1,485 MW, earliest ISD of 2026 (decisions on whether to construct Conawapa and timing will be made over the next few years)
- A domestic Alternating Current (AC) transmission line associated with Keeyask and Conawapa;
- Subject to US and Canadian regulatory approvals, 750 MW of additional transmission interconnection import/export capacity between Manitoba and Minnesota and Wisconsin with an ISD of 2020
- Estimated total cost $16.4 billion
- New major export sales with:
  - Minnesota Power (MP) — 250 MW (2020-2035), and
  - Wisconsin Public Service (WPS).

1.3 APPROACH

1.3.1 Perspectives

The completion of the scope of work was approached from two perspectives:

- First, to confirm to the public that the degree of skill, care, and diligence required was followed by Hydro for the costing work done to date, and to confirm that the costing work done meets utility best practices and procedures; and
- Second, to perform a summary review of the costs presented. Given the magnitude of the project under consideration the cost estimation could not be reproduced, but the cost breakdown and various elements were reviewed and the reasonableness of select elements were ascertained. For examples, the overall cost estimates for the turbine generators are in an appropriate bracket and the unit prices of excavation and concrete work are similar to what we may expect to see for comparable projects. In this review the team attempted to focus on the elements that may expose the projects to the greatest variance in cost.

1.3.2 Reporting and Outline

The PUB has asked KP to document the results of the company's reviews in two volumes of this report. In the first volume no confidential information is referenced. In a second volume, confidential material is referenced.

Except for Section 1, which highlights the report structure and particular aspects to bear in mind the rest of the reports are structured to address each of the PUB's questions to KP in turn as per Appendix B.

1.3.3 Material Reviewed and Information Requests

Knight Piésold reviewed Hydro's documentation submitted to the PUB, prepared Information Requests (IRs) to and reviewed responses from Hydro, and met and corresponded with Hydro's staff.

A complete list of the material provided by Hydro and the PUB used in this review can be found in Appendix C. Numerous procedures, feasibility reports, engineering assessments, and risk analyses were reviewed. Individual experts at Knight Piésold were assigned to review the project descriptions, contract documents, capital expenditure forecasts, specifications, standards, timelines, capacity, and capital and operating costs.

1.3.4 Limitations

The Capital Cost Estimate prepared by Hydro for the alternatives development were prepared as a "bottom up" estimate that considered construction productivity and schedules along with the cost of materials, equipment, and labour required for construction. An overall review of the estimating procedures was conducted and unit rates checked for consistency, but a detailed quantity takeoff, minute work breakdown structure and bottom up cost estimate was deemed to be outside of the scope of this review.

1.4 ITEMS NOT INCLUDED IN THE REVIEW THAT MAY WARRANT CONSIDERATION

1.4.1 Manitoba Hydro Professionalism

Throughout the process staff at Hydro was eager to help us with our task within their availability and be as generally open with Knight Piésold. The staff took pride and ownership of the work they have completed. Hydro staff was cautious as required around material deemed commercial sensitive and Knight Piésold is appreciative of the requirement.

1.4.2 Project Optimization from a Purely Economic Perspective

It is apparent that Hydro honed in on the proposed installed capacities and arrangements for the two generation projects through a lengthy planning process. Concessions have apparently been made during the facility design to get the project permitted and authorized, and to get public, union, and First Nations buy-in and approbation. Economic, environmental and social trade-offs were made to arrive at the final proposed configurations. KP has not reviewed the proposed projects from an optimization perspective. For example, there may have been project configurations that were less costly or more optimal, but less attractive from a social or environmental standpoint.

1.4.3 The Development of Large Hydropower Projects through Crown Corporations

There are obvious advantages and disadvantages of developing hydro projects through Crown Corporations. Hydro Crown Corporations tend to have very laborious administrations and exhaustive process requirements developed after years of managing their assets. They also have a legislated duty of reliability and accountability and act as custodians of the public resource.

Generally, it has been noted in the hydropower industry that while there are significant savings for developing small hydro through private ventures, large hydro does not necessarily benefit from independent private development. Nevertheless, there are overhead costs associated with developing projects through Crown Corporations. It is pointed out here because it can have a bearing on the cost and outlook on risk, but discussing the role of Crown Corporations is well outside the scope of the current report.

1.4.4 Capitalized Interest

KP has refrained from commenting on financing, interest on Capital and Capital interest that are the domain of other Independent experts

1.4.5 Gaps

Knight Piésold has provided it best effort in answering the PUBs queries in a timely manner as within the context of the NFAT procedures as the report deadline has drawn to a close and several facets could not be fully investigated with the New Generation Construction Division. These are:

- The methodology and numerical breakdown of the systemic risk calculations
- Contingency determination on the indirects, and
- A justification for not using the Hydro Escalation factor estimated.

2 – REVIEW OF CAPITAL AND O&M COSTS FOR CONAWAPA GS AND KEEYASK GS

2.1 SCOPE OF WORK

Question 1: "Review and assess Manitoba Hydro's capital and operation and maintenance (O&M) cost estimates for Conawapa GS and Keeyask GS, including the adequacy of management reserves for the projects."

2.1.1 Introduction

Knight Piésold has been asked by the PUB to review and assess Hydro's capital and operation and maintenance (O&M) cost estimates for Conawapa GS and Keeyask GS, including the adequacy of management reserves. Capital costs comprise Direct Costs and Indirect Costs. Note there is some overlap between Question 2 and Question 3 pertaining to the indirect costs and Question 4 pertaining to the contracting, scheduling and management aspects (Sections 3, 4 and 5 of this report respectively). Some general considerations pertaining to costs have been summarized in this section and will not be repeated in Section 3.Direct Costs

2.1.2 Direct Costs

Direct cost items are those directly attributable to the construction of the primary asset under construction (e.g. concrete costs, excavation costs, major equipment etc.). These costs are developed in accordance with the design, quantities and contract packaging established by the project definition.

The Direct Costs Include:

- River Management During Construction
- Earthfill Dams and Dykes
- Spillway and Transition Structures
- Powerhouse Complex (including Power Intakes)
- Miscellaneous Directs, and
- Escalation to Start of Construction (from date of estimate).

2.1.3 Indirect Costs

Indirect Costs are discussed in Section 3.

2.1.4 O&M Costs

O&M Costs are discussed in Section 2.15.

2.2 FIRST IMPRESSIONS ON VERY BROAD TERMS

Very broadly speaking, the investment costs of large hydropower plants such as Keeyask and Conawapa range anywhere from $2 million/MW installed to $10 million/MW installed. The proposed Keeyask and Conawapa facilities are approximately $9 million/MW and $7 million/MW respectively, including all the indirect costs and inflation. They are therefore high in the ballpark (compared to a more general figure of around $4 million/MW) but costs are very site-sensitive, and these two sites are not particularly favourable for hydropower development, situated as they are on large relatively flat rivers – the dams have to be long, the head across them is not high and they have to incorporate significant spillways. The other common comparative metric is an effective cost/benefit ratio where total cost is divided by the estimated average annual energy production. At 1.40 and 1.45 M$/GWh Keeyask and Conawapa are again at the high end of the typical range. Table 2.1 compares these metrics and other data for a number of large new Canadian hydro projects currently under consideration in various jurisdictions.

Table 2.1 High Level Comparison of Capital Cost Estimates

Name	Prov.	Proposed Installed Capacity (MW)	Estimated Average Annual Energy (GWh)	Total Estimated Capital Cost	M$ / MW	M$ / GWh	Source:
Muskrat Falls (*no Labrador Island Link)	NL	824	4,600	2.9 B$* 6.2 B$	3.5* 7.5	0.60* 1.35	Muskrat Falls Review
Site C	BC	1,100	5,100	7.9 B$	7.2	1.55	Site C information fact sheet.
Petit Mecatina Projects	QC	1,200	5,500	not available for review			
La Romaine	QC	1,550	8,000	6.5 B$	4.2	0.80	www.aecom.com
Keeyask	MB	695	4,400	6.2 B$	8.9	1.40	NFAT Filing
Conawapa	MB	1,485	7,000	10.2 B$	6.9	1.45	NFAT Filing
Wuskwatim	MB	200	1,520	1.78 B$	8.8	1.17	Actual Final

2.3 DISCUSSION OF CLASSIFICATION AND ACCURACY

2.3.1 General Purpose

Most of the NFAT aspects Knight Piésold was asked to provide input on involve a review of costs and the associated accuracy; with that regard it is particularly important to recognize the appropriate classification of the estimates and the respective uses made of said estimates. Typically the expected accuracy range of the capital cost estimate is commensurate with a project stage and decision making milestone; however as pointed out by the International Association for the Advancement of Cost Engineering (AACE) this is secondary to the maturity level of the project definition.

2.3.2 Recommended Practices

Hydro has adopted the recommended practices of the AACE for the production and presentation of its cost estimates. AACE Recommended Practice (RP) Nos. 17R-97 and 69R-12 are of particular relevance. Table 2.2 shows how the AACE highlights the importance of the maturity level of the project definition deliverables over the secondary characteristics.

Table 2.2 AACE International Recommended Practice No. 17R-97 - Generic Cost Estimate Classification Matrix

	Primary Characteristic	*Secondary Characteristic*			
ESTIMATE CLASS	**MATURITY LEVEL OF PROJECT DEFINITION DELIVERABLES** Expressed as % of complete definition	**END USAGE** Typical purpose of estimate	**METHODOLOGY** Typical estimating method	**EXPECTED ACCURACY RANGE** Typical +/- range relative to index of 1 (i.e. Class 1 estimate) [a]	**PREPARATION EFFORT** Typical degree of effort relative to least cost index of 1 [b]
Class 5	0% to 2%	Screening or feasibility	Stochastic (factors and/or models) or judgment	4 to 20	1
Class 4	1% to 15%	Concept study or feasibility	Primarily stochastic	3 to 12	2 to 4
Class 3	10% to 40%	Budget authorization or control	Mixed but primarily stochastic	2 to 6	3 to 10
Class 2	30% to 75%	Control or bid/tender	Primarily deterministic	1 to 3	5 to 20
Class 1	65% to 100%	Check estimate or bid/tender	Deterministic	1	10 to 100

NOTES:

[a] If the range index value of "1" represents +10/-5%, then an index value of 10 represents +100/-50%.
[b] If the cost index value of "1" represents 0.005% of project costs, then an index value of 100 represents 0.5%
[c] AACE International Recommended Practice No. 17R-97. COST ESTIMATE CLASSIFICATION SYSTEM. TCM Framework: 7.3 – Cost Estimating and Budgeting. Rev. November 29, 2011

2.3.3 Suggested Classification

Table 2.3 summarises the classification of the various Hydro estimates as provided by Hydro. However, it is KP's opinion that by default the maturity level of the definition deliverables of a generic wind farm, solar farm or gas plant will be higher than that of a generic building, manufacturing plant, or hydroelectric facility, since the large proportion of "off the shelf" equipment automatically provides a more mature definition. As such a wind farm, solar farm or gas plant should have a higher classification than given by Hydro despite the identical end usage of the estimate; as a result KP does not entirely agree with the classifications made by Hydro. In addition KP believes the Keeyask and Conawapa hydroelectric projects are at a higher definition level than Hydro indicates despite not have an improved level of accuracy.

Table 2.3 Estimate Classification for Manitoba's Resource Options

	Purpose of Estimate	AACE Class Per MH Statement in Appendix 7.2	KP Assessment of Maturity Level of Project Definition	KP AACE Classification
Keeyask Infrastructure Project (KIP)	Control	Class 3 (p. 45)	65% to 100%	Class 1
Keeyask Generating Station Project (KGSP)	Budgetary Approvals and Request for Proposals		30% to 75%	Class 2
Conawapa Generating Station Project (CGSP)	Budgetary Approvals	Class 3 (p. 55)	30% to 75%	Class 2
Gas Options	Comparative Resource	Class 4 (p. 178, 187)	10% to 40%	Class 3
Wind Power Options	Comparative Resource	Class 5 (p. 334)	10% to 40%	Class 3
Solar Power Options	Option Screening	Class 5 (p. 289)	1% to 15%	Class 4

2.3.4 Expected Accuracy Range

The expected accuracy range is an indication of the amount by which the closing project cost might vary from the estimated cost. Accuracy is traditionally expressed as a +/- percentage range around a "point" or best-guess estimate, with a stated level of confidence that the actual cost outcome would fall within this range (+/- measures are a useful simplification, given that actual cost outcomes have different frequency distributions for different types of projects).

Note that in Table 2.2, the values in the accuracy range column do not represent + or - percentages, but instead represent an index value relative to a best range index value of 1. If, for a particular industry, a Class 1 estimate has an accuracy range of +10/-5 percent, then a Class 5 estimate in that same industry may have an accuracy range of +100/-50 percent.

In addition to the maturity level of the project definition, estimate accuracy is also driven by other systemic risks such as:

- Level of non-familiar technology in the project.
- Complexity of the project.
- Quality of reference cost estimating data.
- Quality of assumptions used in preparing the estimate.

- Experience and skill level of the estimator.
- Estimating techniques employed.
- Time and level of effort budgeted to prepare the estimate.

Systemic risks such as these are often the primary driver of accuracy; however, project-specific risks (e.g. risk events) also drive the accuracy range.

2.4 KEEYASK G.S. AND CONAWAPA G.S. CAPITAL COST ESTIMATE GENERAL METHODOLOGY

The total cost to build a project (including the capital cost in constant dollars, plus price escalation between the date of the estimate and the date of actual expenditures, plus capitalized interest to reflect the opportunity cost of funds utilized or the cost of actual borrowings for the project, plus the transfer-in of pre-project design and study costs that have not otherwise been recovered through amortization) is referred to as the in-service cost.

Appendix 2.4 is the core section of the Manitoba Hydro NFAT Submission, presenting the development of the cost estimates for the proposed Keeyask and Conawapa GSs. The appendix states: *"The Point Estimate is the first step in the estimate development process."* However Knight Piésold considers that there are a few elements that should be considered prior to jumping into the Point Estimate, primarily the purpose of the estimate, the process, the project definition, the breakdown structure, and the data with which the estimate will be built.

Figure 2.1 illustrates Hydro's Cost Estimate Development Process as described in Appendix 2.4 of the Submission. After determination of the Point Estimate (including Direct and Indirect costs, a Contingency and a Management Reserve are added to create the Base Cost at a certain date. Interest and Escalation plus Money Spent-to-Date (incurred expenditures and interest) are then added to obtain the In-Service (i.e. total estimated final project) Cost which is also the Project Budget.

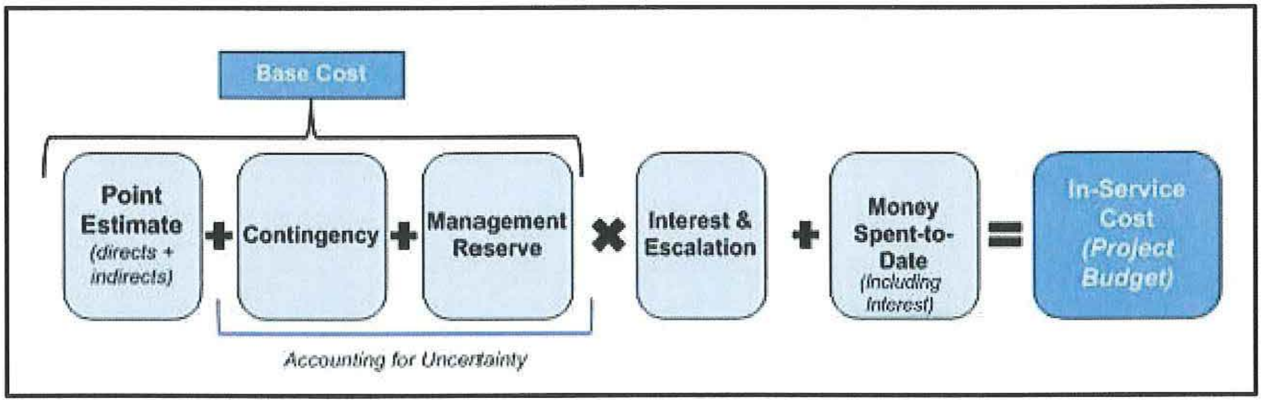


Figure 2.1 Manitoba Hydro's Cost Estimate Development Process

2.4.1 Purpose of Estimate

The Point Estimates for Keeyask and Conawapa are based on separate Cost Estimate Reports by KGS ACRES in 2009 and 2010 respectively. The development of the estimates was performed in association with defined Estimate Plans. The plans presented objectives, scope and methodologies on which the cost estimates were to be based. Copies of these key reports were reviewed in confidence by KP.

Identical cost estimating objectives and intended use were stated in the two reports.

2.4.1.1 Cost Estimating Objectives of the Cost Estimate by KGS ACRES

"(a) Incorporate the most recent design updates. A number of minor design changes have been implemented since the previous cost estimate was prepared by KGS ACRES in 2007. These changes were primarily associated with earthworks structures and with channel improvements/optimizations.

(b) Incorporate the most current contract packaging philosophies, some of which are based on the Wuskwatim contract packaging model.

(c) Incorporate changes to the estimating process that were made following the preparation of the previous estimate in 2007.

(d) Incorporate lessons learned from the tendered prices received for various contracts on the Wuskwatim GS project.

(e) Engage personnel from MH's Project Services Department in the cost estimating process, to provide them with a clear understanding of the basis for the estimate."

2.4.1.2 Intended Use of the Cost Estimate

"After appropriate contingencies to account for project risks have been assigned, it is intended that the estimate will be used by MH and KGS ACRES for the following purposes:

- *The estimated direct costs for the Principal Structures will be combined with MH's estimated indirect costs (referred to as MH's indirects) and will be used by MH in the economic evaluation of the project.*
- *The estimated costs and related resource information will be used to provide a basis for the development of updated workforce estimates.*
- *The estimated costs and resource information will be used as a basis for assessing design alternatives during the final design phase of the project."*

2.4.1.3 PUB vs. Manitoba Hydro End Use

It is important to note that the PUB and Manitoba Hydro are making different uses of the same cost estimate (with a specific level of project definition) and as a result may have a different perspective on risks and accounting for uncertainty which are built into the relevant contingency and reserves.

2.4.2 Definition of the Project Characteristics and Costs

The most pertinent description of each generating station is also found in the cost estimating reports. KP is of the opinion that both projects are at an advanced stage of project definition with well-established sets of engineered drawings and specifications. The Keeyask Project is described in Sections 2.5 and 2.6 and the Conawapa Project in Sections 2.7 and 2.8 below. The project characteristics and costs have been prepared by a reputable consulting engineering consortium (KGS ACRES) with suitable hydroelectric power development experience and they appear to be reasonable.

2.4.3 Direct Costs Work Breakdown Structure (WBS)

The Basis of Cost Estimate Reports include well-defined WBSs that appear to be inclusive of all direct cost considerations.

The direct costs for both generating stations have been broken down into 5 major components:

- River Management
- Earthfill Dams and Dykes
- Spillway, Walls and Transition Structures
- Powerhouse Complex, and
- Miscellaneous Directs.

The preparation of the direct cost estimate is also based on an approach to contract packaging that is further reviewed in Section 4. The selected contract packaging has a bearing on the selected WBS.

The methodologies and work breakdown structures provided represent just one possible approach to undertaking the defined work. There may be other approaches that contractors may adopt in completing their work; these will be considered during the tender and an Early Contractor Engagement process (see Section 4.)

2.4.4 Database

The cost estimates have been prepared using the active databases maintained by Hydro and utilized in their project cost estimates. These databases were utilized in the preparation of estimates from first principles (i.e. costing all the elements of materials, labour and equipment needed to construct each item of work).

2.4.4.1 Productivity

Generally productivity is based on the assumed construction equipment, construction methodology and labour force for the work. For example, for earthworks, productivity was calculated from first principles using Caterpillar developed software that incorporates these elements. KGS Acres reported that in general productivity in the 2009 and 2010 reports were assumed to be similar to that which has been achieved on the most recent Hydro northern hydroelectric generating station project (Limestone GS). In KP's discussions with the New Generation Construction Division of Hydro it appears that the productivity values have been compared and found comparable to other productivity rates being experienced in the construction industry at the time of the estimate.

One important aspect of the productivity rates assumed was that productivity rates would not be as low as the productivity rates experienced during the construction of the Wuskwatim facility.

2.4.4.2 Material Costs

Material costs are expressed in $/unit. Hydro states that construction material costs (e.g. cement, reinforcing steel, lumber and formwork components) are based on quotations from multiple suppliers.

2.4.4.3 Labour Costs

The labour cost ($/man-hour) database was developed for both craft and staff labour rates. A "craft" worker is an employee who is working 'on the tools'. Craft labour rates are governed by the Burntwood Nelson Agreement (BNA). Total labour rates include the base labour rate, overtime, employer paid benefits, employer paid burdens, shift premiums and Worker Compensation Board requirements.

Supervisory employees (e.g. superintendents, engineers, management) are termed 'staff' workers and are not included in the BNA. Wage rates for staff positions (administration and management) are based on information from Canadian Human Resources Websites, APEGM Salary Survey, and other similar sources and are adjusted to reflect the remoteness of the site.

2.4.4.4 Equipment Costs

Hydro's equipment costs database outlines the cost of equipment that will be used for the work. The equipment costs are established as $/hour rates and based on standard industry costs. Rates include equipment list price, maintenance costs, economic life, fuel consumption and resale price but not mobilization costs. Industry rates are then adjusted for exchange rates, mechanics' wage rates, sales tax, gas and diesel fuel rates, etc. to tailor them to the particular project. KP confirms that the equipment rates provided to KP are similar to those published in RS Means or Caterpillar publications.

2.4.5 Point Estimate

Hydro defines the Point Estimates as risk-free, escalation-free cost estimates based on an initial set of assumptions and current market conditions (i.e. overnight costs). Quantities used in the preparation of the estimates were based on design drawings and project parameters in 2010 for Conawapa and 2009 for Keeyask.

The direct cost estimates employed a combination of different estimating methods to develop the overall estimates for the scope of work described. The method involved:

- First principles and the databases described above were used to cost items under the General Civil Contractor scope or pertaining to earthworks and concrete structural work.
- Contractor indirect costs are included in the overall project direct costs and accounted for in the first principles estimate. Contractor indirects include items such as mobilization, supervisory staff costs, site facility costs and allowances for profit and overhead (including subcontractor profit associated with a specific list of subcontracts).
- The turbines, governors, generators and exciters were derived from manufactures quotations.
- Gates, stoplogs, trashracks, major mechanical equipment (cranes, elevators, HVAC) and major electrical equipment were derived from numerous fabricator quotations.
- Allowances and provisional sums.

KP has reviewed the Direct Estimate Cost Tables at a high level and found the indicated quantities and unit rates to be reasonable and appropriate to what can be expected.

2.5 KEEYASK GS PROJECT DEFINITION

2.5.1 Project Definition Documents

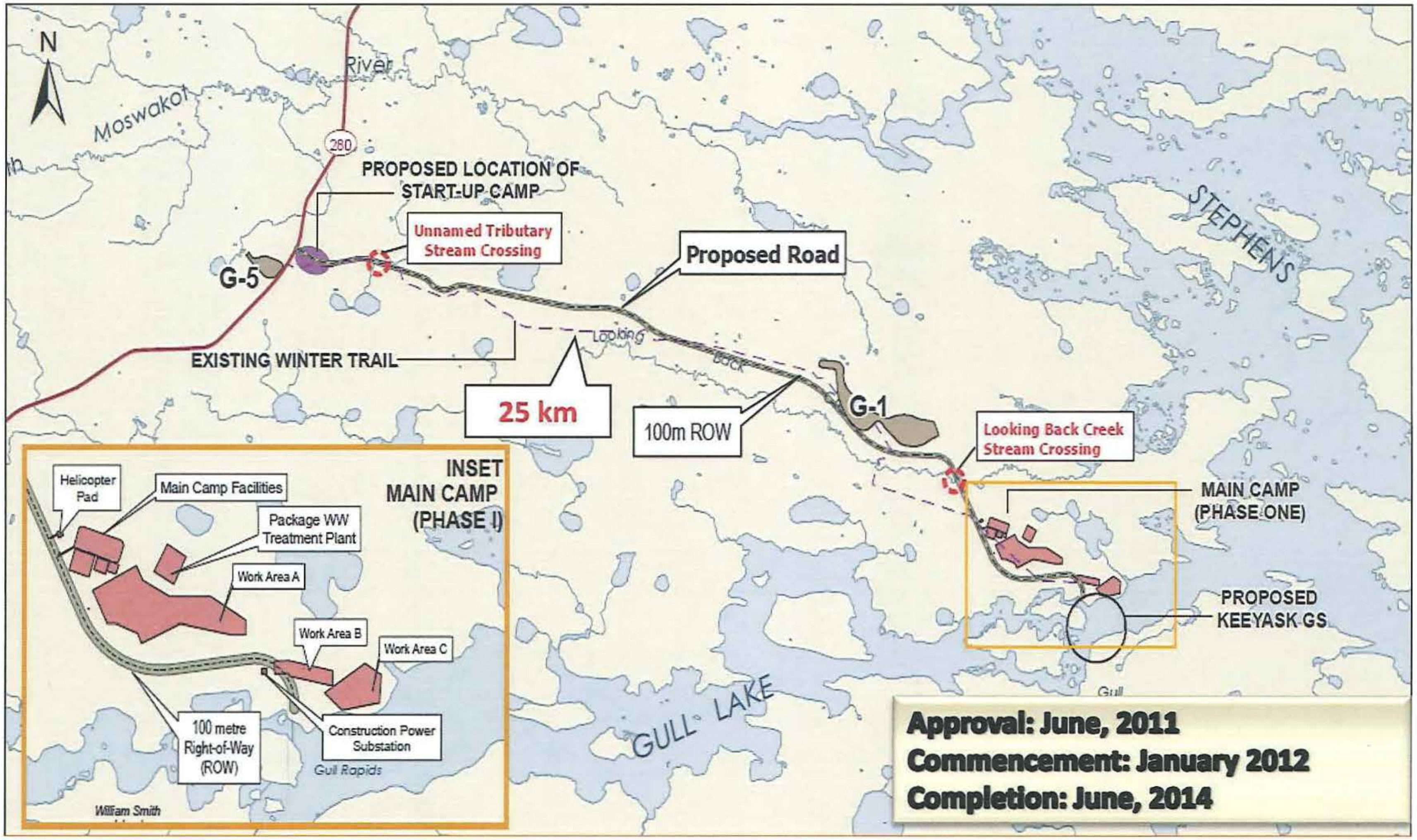
KP reviewed Hydro's Project Definition descriptions in Section 2.1 of the NFAT Submission as well as selected segments of the Environmental Impact Statement (EIS) and the Basis of Cost Estimate Report (December 2009).

2.5.2 The Keeyask Project

The Keeyask Project is a 695 MW hydroelectric project that is scheduled to take seven years to construct, with a total budgeted in-service cost estimate of $6.2 billion including interest and escalation based on a 2019/20 In-Service-Date (ISD). The overall development has been separated into two separate projects: the Keeyask Infrastructure Project (KIP, discussed in Section 3 and shown conceptually in Figure 2.2 and the Keeyask Generating Station Project (KGSP, shown conceptually in Figure 2.3. Hydro will own and operate the KIP, whereas the KGSP will be owned by a partnership between Hydro and four Keeyask Cree Nations (KCNs): Tataskweyak Cree Nation (TCN), War Lake First Nation (WLFN), York Factory First Nation (YFFN) and Fox Lake Cree Nation (FLCN). The Joint Keeyask Development Agreement addresses the KCNs' income-sharing, training, employment, business opportunities, and involvement in environmental and regulatory affairs.

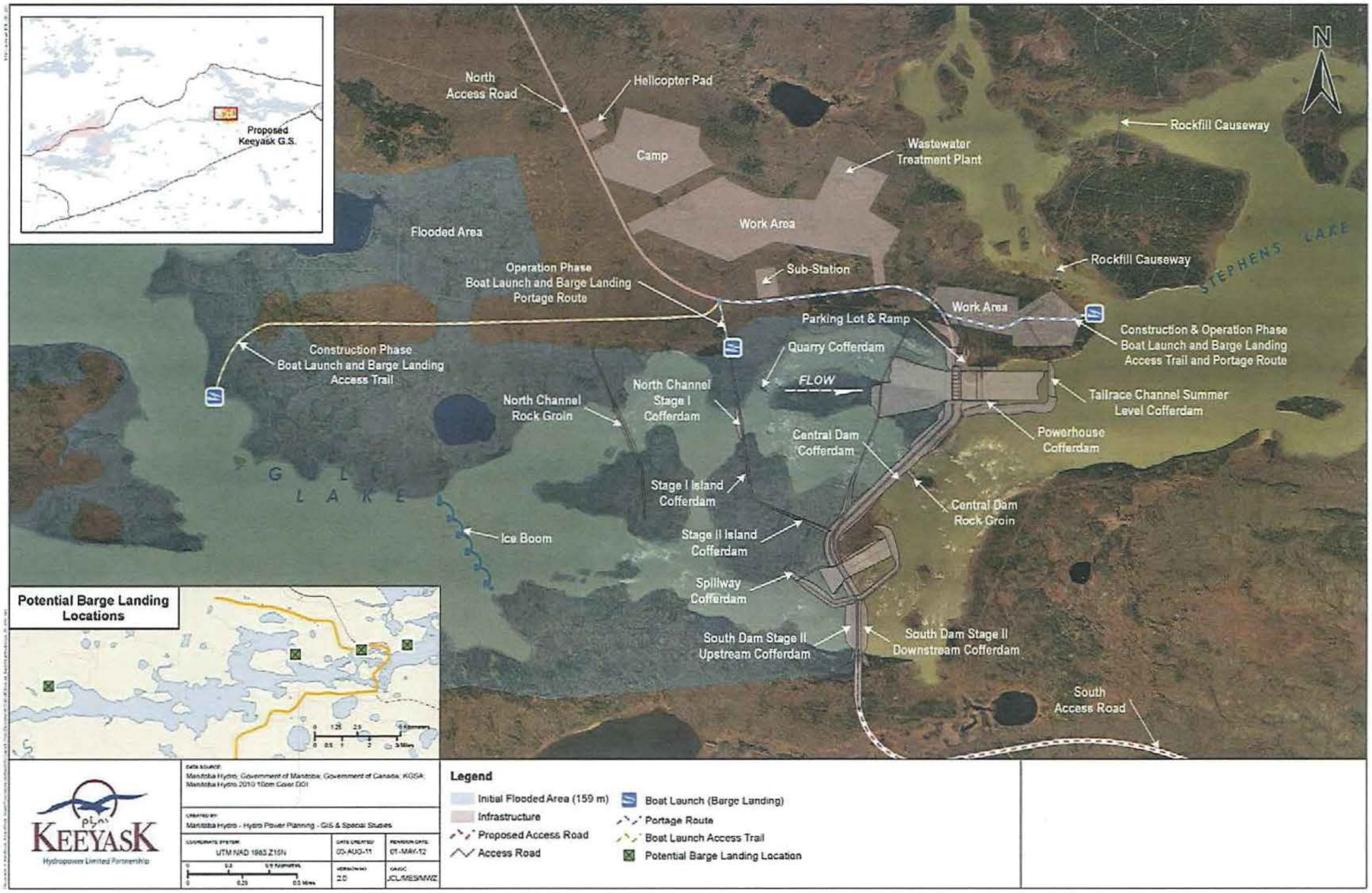
Construction of the KGSP includes the following major activities:

- The development of borrow area and quarries for construction material
- An ice boom
- A powerhouse complex on the north side of Gull Rapids with seven turbines and service bay
- A seven bay spillway on the south side of Gull Rapids
- Three dams across Gull Rapids (North, Central and South)
- Dykes on both the north and south sides of the reservoir
- A South Access road to Gillam
- Cofferdams to facilitate construction, and
- Increasing the Main Camp (Phase II) accommodations by 1,500 (a Phase I camp is provided as part of the KIP).



NOTE
(Source: MH NFAT Submission Map 2.2)

Figure 2.2 Keeyask Infrastructure Project



NOTE:
(Source: MH NFAT Submission Figure 2.3)

Figure 2.3 Keeyask Generating Station Project

2.5.3 Appreciation for the Project Layout

Overall the project layout and the proposed project staging are relatively complex but the plans are deemed appropriate for the large scale of the site. The general arrangement is unique compared to other Hydro projects in that the river closure is much more spread out than on past projects, with powerhouse and spillway separated by a dam, and the inclusion of extensive dykes. Typical Hydro construction methodology seems in the past to have followed a 2 stage diversion process whereas Keeyask will have multiple diversions and cofferdam stages for the construction of the various components.

2.6 KEEYASK GS COST ESTIMATE

The overnight cost of the KGSP was estimated by KGS Acres in 2009 as [redacted], broken down as shown in Table 2.4. The overnight cost is the cost of a construction project if no interest or escalation was incurred during construction, as if the project was completed "overnight."

The overnight cost of the CGSP was estimated by KGS Acres in 2010 as [redacted], broken down as shown in Table 2.4.

Table 2.4 Keeyask GS Reported Direct Cost Estimate by Major Works

	2009 M$[1]
River Management	[redacted]
Earthfill Dams and Dykes	[redacted]
Spillway, Walls and Transition Structures	[redacted]
Powerhouse Complex	[redacted]
Miscellaneous Directs	[redacted]
Total Estimated Direct Costs (without Contingency)	[redacted]

Source: [1] C.I.: KGS ACRES Ltd., June 1, 2010, Keeyask Generating Station – Final Design Phase – Basis of Cost Estimate Report – December 2009 Cost Estimate, Document No. H333175-7201-92-236-0001.

As a reality check, overall material quantities were provided by Hydro and KP used typical unit prices to produce an independent high level cost estimate, as shown in Table 2.5. The breakdown is completely different from that in Table 2.4 and affords some comfort that the cost estimate is in the correct ballpark.

Table 2.5 Keeyask GS Order of Magnitude Metric Cost Estimate

	Quantity[1]	Unit	Unit Cost[2] ($)		Cost ($)
Excavation					
Unclassified	3,100,000	m^3	20		62,000,000
Rock	2,000,000	m^3	100		200,000,000
Coffer Dam removal	600,000	m^3	20		12,000,000
Earth Fill	6,700,000	m^3	40		268,000,000
Concrete	400,000	m^3	1,200		480,000,000
Capacity (Generating Plant)	700	MW	500,000		350,000,000
					1,372,000,000
+20 % for miscellaneous items					274,400,000
					1,646,400,000

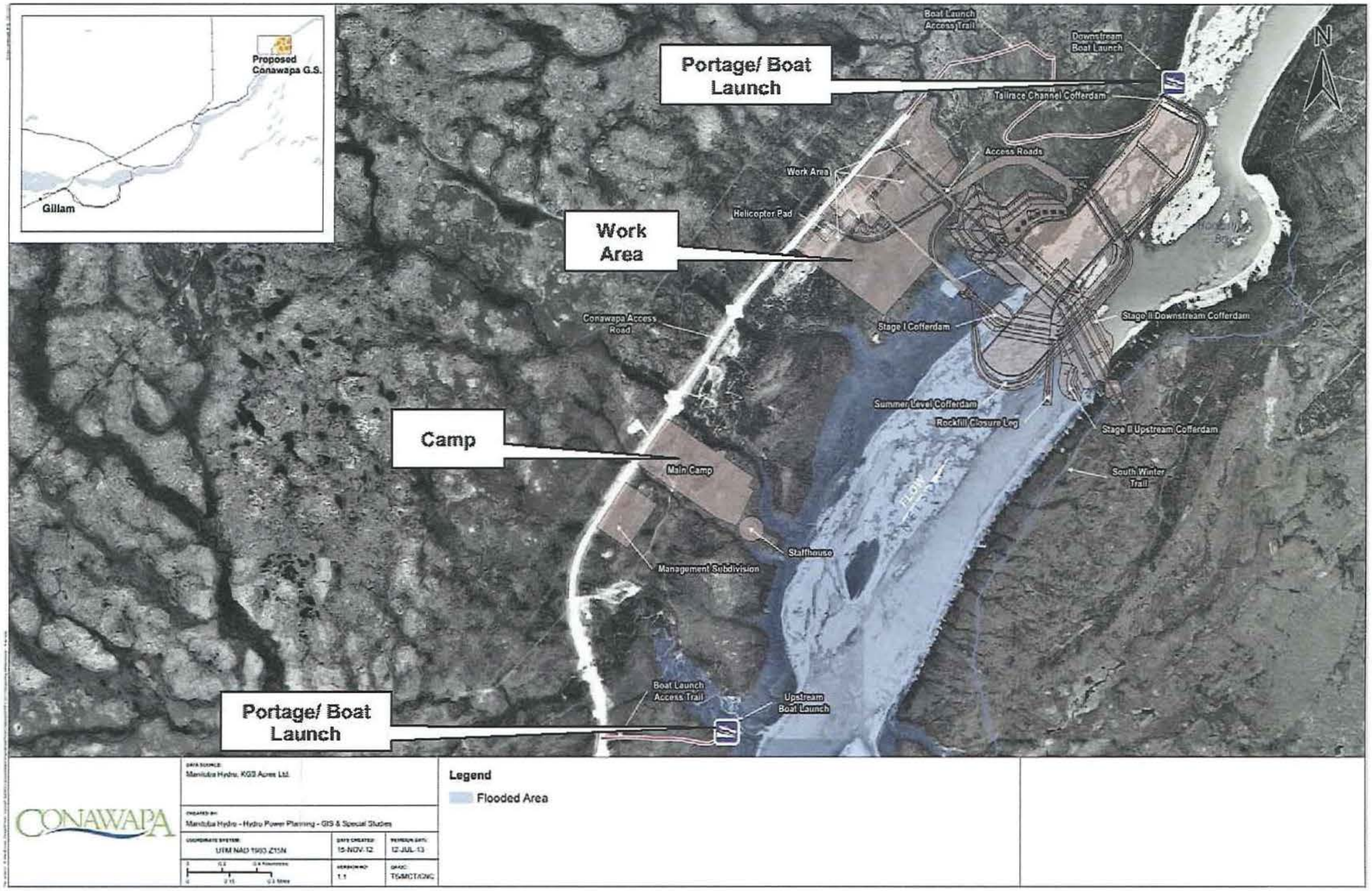
Source: [1] Environmental Impact Statement and Summary of Quantities provided by MH (white paper). [2] KP Generic Estimate.

2.7 CONAWAPA GS PROJECT DEFINITION

Unlike Keeyask, the Conawapa development comprises a single project, the Conawapa Generating Station Project (CGSP), shown conceptually in Figure 2.4. The project will produce 1,485 MW of power and is scheduled to take 10 years to construct, at a cost estimated at $10.2 Billion, including interest and escalation based on the earliest anticipated ISD of 2025/26.

The proposed layout and design of Conawapa GS are not presently as advanced as those for Keeyask but appear to be well defined and consistent with good industry practices. More specifically:

- The proposed general arrangements of the permanent works appear to be reasonable for the optimum development in terms of cost and construction duration.
- Based on the information provided, the design and construction is consistent with good engineering and construction practices, and should not pose any unusual risks for construction or operation of the facilities.
- The available studies have identified technical risks and appropriate risk mitigation strategies.



NOTE:
(Source: MH NFAT Submission Figure 2.7)

Figure 2.4 Conawapa Generating Station Project

2.8 CONAWAPA GS COST ESTIMATE

The overnight cost of the CGSP was estimated by KGS Acres in 2010 as [redacted], broken down as shown in Table 2.6.

Table 2.6 Direct Cost Estimate by Major Works

	2010 M$[1]
River Management	[redacted]
Earthfill Dams and Dykes	[redacted]
Spillway and Transition Structures	[redacted]
Powerhouse Complex	[redacted]
Miscellaneous Directs	[redacted]
Total Estimated Direct Costs (without Contingency)	[redacted]
Source: [1]KGS ACRES Ltd., October, 2011, Conawapa Generating Station – Stage IV Design – Basis of Cost Estimate Report – November 2010 Cost Estimate, Document Manitoba Hydro File 00192-04220-0114_00	

As a reality check, overall material quantities were provided by Manitoba and KP used typical unit prices to produce an independent high level cost estimate, as shown in Table 2.7. The breakdown is completely different from that in Table 2.6 and affords some comfort that the cost estimate is in the correct ballpark.

Table 2.7 Conawapa GS Order of Magnitude Metric Cost Estimate

	Quantity[1]	Unit	Unit Cost[2] ($)		Cost ($)
Excavation					
Unclassified	6,400,000	m^3	20		128,000,000
Rock	840,000	m^3	100		84,000,000
Coffer Dam removal	1,545,000	m^3	20		30,900,000
Earth Fill	9,050,000	m^3	40		362,000,000
Concrete	835,000	m^3	1,200		1,002,000,000
Capacity (Generating Plant)	1,500	MW	500,000		750,000,000
					2,356,900,000
+20 % for miscellaneous items					471,380,000
					2,828,280,000
Source: [1] Summary of Quantities provided by MH (white paper.) (2) KP Generic Metric.					

2.9 CONTINGENCY

2.9.1 Definitions

When estimating the cost of a project there is always uncertainty as to the precise content of all items in the estimate, how work will be performed, what work conditions will be like when the project is executed, what each item of work will end up costing and so on. These uncertainties are risks to the project. Some refer to these risks as "known-unknowns" because the estimator is aware of them but cannot precisely estimate them, even if, based on past experience, he can make some estimate of their probable costs.

AACE has defines contingency as:

"An amount added to an estimate to allow for items, conditions, or events for which the state, occurrence, or effect is uncertain and that experience shows will likely result, in aggregate, in additional costs. Typically estimated using statistical analysis or judgment based on past asset or project experience.

Contingency usually excludes:
1. *Major scope changes such as changes in end product specification, capacities, building sizes, and location of the asset or project;*
2. *Extraordinary events such as major strikes and natural disasters;*
3. *Management reserves; and*
4. *Escalation and currency effects".*

2.9.2 Methodology

At a high level the Hydro contingency development process involved the development of a contingency curve whereby the capital cost Point Estimate was expressed in terms of a probability of budget under- or over-run. An amount was then added to provide what is termed the P50 value i.e. there is an equal chance that the final cost would be higher or lower than the stated amount. The difference between the P50 value and the Point Estimate is defined as the project Contingency. According to Appendix 2.4, the contingency was developed using the AACE recognized Parametric and Expected Value Modeling method (RP's 40R-08, 42R-08, 44R-08.) Hydro applied this method internally with the help of an outside consultancy. In addition, KGS ACRES participated in meetings in April 2010 during which potential risks and uncertainties associated with the direct cost items were identified and discussed amongst members of the project team. They helped review the basis for selecting contingency and helped establish a basis for assessing contingency for project specific risks by applying an expected value approach.

The contingency estimate aggregates two types of risk:
- Systemic Risk, and
- Project Specific Risk.

Systemic risks are those that are inherent to the project development process and are not unique to the project. In general, as a project advances in development, systemic risks are reduced or develop into project specific risks. Items covered under these two risk categories are shown in Table 2.8. The project WBS was broken down into work packages, and grouped to allow for contingency development and the identification of work-package specific risks, while allowing for the systemic contingency risks to be evaluated.

Table 2.8 Systemic vs. Project Specific Risk

Systemic Risks evaluated through Parametric Estimating	Project Specific Risks evaluated using Expected Value
Process Definition	Weather
Project Definition	Site Subsurface Conditions
Project Management and Estimating Process	Delivery Delays
	Constructability
	Resource Availability
	Project Team Issues
	Quality Issues (e.g. rework)

2.9.2.1 Parametric Estimating

A parametric model is an equation developed based on empirical data that explicitly links risk drivers to cost change, and as such takes the quantified systemic risks as an input and produces expected cost. The development of a parametric model is a challenging aspect of the proposed project. The actual systemic risk ratings were those of the external risk expert and the Hydro team.

KP has an understanding and appreciation for systemic risks, but was not able to fully ascertain how these were quantified by Hydro with the material provided by them or through a review of RP 42R-08. KP has reviewed both the New Generation Construction Risk Management Procedure (RSK-001) and the Project Contingency Management Procedure (RSK-002), and the Keeyask Project Risk Register that follows these procedures which includes a probability of occurrence of particular risks and a monetary value associated with those risks.

2.9.2.1 Expected Value

KP has a better understanding and appreciation for how the project specific risks were determined through Expected Value Modeling. KP has not looked into this model in detail but it was discussed at some length during teleconferences with the New Generation Construction Division. The adopted process appears to be more akin to what KP would call a Monte Carlo simulation.

2.9.2.2 Monte Carlo Simulation

MCS is an advanced quantitative technique for analysing risk that provides a structured way of setting the contingency value in a project cost estimate. The output of MCS when applied to estimating project cost is a probability distribution for the total final cost of the project.

As noted by John K. Hollman in "The Monte-Carlo Challenge: A Better Approach" from a 2007 AACE International Transaction, Monte Carlo techniques for estimating contingency are noted to fail for three basic reasons:

- Users are not recognizing dependencies between model variables,
- They are not modeling the relationships of risk drivers to cost outcomes, and
- They fail to recognize the differences between systemic and project specific risks.

However, the Hydro approach is relatively new in attempting to address the Systemic and Specific risks in a distinct manner.

2.9.3 Selection of the P50

2.9.3.1 Manitoba Hydro Policy

In CAC/MH I-001, Hydro stated:

"In fall 2009, Manitoba Hydro adopted the approach to utilize cost estimates at a P50 confidence level and management reserves to establish cost estimates for major capital projects. This approach was developed as a result of an international review of electric and other industries."

2.9.3.2 Use of the P50 by Others

According to CAC/MH I-002b, BC Hydro uses P50 for establishing the contingency amounts for capital projects and refers to it as "Expected Cost Estimate". BC Hydro also uses the difference between the P90 and the P50 to calculate a component of the "Project Reserve" for budget authorizing purposes. Hydro Quebec uses P50 for establishing the contingency amount for new projects and P70 for rehabilitation projects.

2.9.3.3 Argument for the use of a lower probability of overrun

KP and Hydro have not been able to identify a standard that outlines the "correct" level of contingency to include. The level at which to fund a project is specific for each estimate user.

While a corporate contingency guideline of 50 percent probability of overrun for projects that are part of a total annual capital budget may be fine in incidences where numerous smaller capital projects make up this total annual budget and where cost variations on one project may be offset by those on another project, this may not be the case for large projects.

An article entitled *"Monte Carlo Analysis: Ten Years of Experience"* (from Cost Engineering, a publication of the American Association of Cost Engineers, Vol 43/No. 6 June 2001) states:

"The 50 percent probability guideline is not applied to very large projects or to strategic projects outside the annual capital budget. For these, the 10 percent to 20 percent probability of overrun is often acceptable. When applying MCA (Monte Carlo Analysis) to projects at a very preliminary stage, management usually requires a very low probability of overrun, possibly 5 percent. Some of the items, conditions, or events for which the state, occurrence, and/or effect is uncertain include, but are not limited to, planning and estimating errors and omissions, minor price fluctuations (other than general escalation), design developments and changes within the scope, and variations in market and environmental conditions. Contingency is generally included in most estimates, and is expected to be expended."

2.9.3.4 Contingency Amounts Associated with a lower probability of overrun

In KP/MH II-026a Hydro has provided the following contingency amounts for the Keeyask Project. This could be used to re-estimate the project contingency if the decision maker wanted less than a 50/50 chance of under-run or over-run on the project cost. If for example, it was deemed more prudent to use a P90 level rather than a P50, an extra contingency of $423 million would be added.

Table 2.9 Keeyask Contingency Amounts

P-Value	Contingency Amount
P50	$527 million
P80	$848 million
P90	$950 million
P95	$,1032 million

2.9.4 Reducing Contingency through Contracting Method

Contingency is the portion of project budget that is available to cover uncertainty in the project estimates. In essence, this uncertainty can be handled either within the contracts or outside them. For example, contracting lump sum tends to increase contract costs (as contractors need to include more margin in their overheads to cover the risks) but to reduce the level of contingency required (by Hydro) because the risks have already been covered. Recent KP experience has been that it is more appropriate and affordable to share risk between owner and contractor (i.e. not to use Lump Sum methods where there are significant construction risks); they therefore affirm Hydro's basic approach.

2.10 ESCALATION AND ESCALATION MANAGEMENT RESERVES

Since the Keeyask and Conawapa projects will not be complete until about 2022 and 2028, escalation is a major contributor to the project costs and can represent anywhere from 10 to 20% of the total project in-service cost, depending on the date of the base estimate and the escalation rates assumed. Escalation refers to cost changes which result from changes in price levels that are in turn driven by underlying economic conditions. It is driven by changes in productivity, technology, and market conditions, including high demand, labour and material shortages, profit margins, and other factors. It includes the effects of inflation, but is fundamentally different. Inflation refers to general changes in price levels caused by changes in the value of currency and other broader monetary impacts.

2.10.1 Consumer Price Index

Hydro's normal practice has been to assume that future costs will increase at a rate generally consistent with the CPI, using the future CPI levels targeted by the Bank of Canada. They escalate costs in the price of specific goods or services associated with hydro-electric generation projects and natural gas-fired generation projects through a process called 'real escalation', as it has been determined that they change in price differently than more general cost escalators like the CPI. One off the main driver of the projected cost increase between capital expenditure forecasts has been that CPI has been much lower than the actual escalation for the project.

In Table 3 of Appendix 2.4, escalation at CPI (1.9%) is calculated to convert the base dollar estimate to nominal dollars and is included in the "In-Service Cost". Assumed escalation amounts are shown in Table 2.10

Table 2.10 Escalation at Consumer Price Index Levels

	Escalation at Consumer Price Index Levels in Capital Expenditure Forecast 2012
Keeyask	0.42 B$
Conawapa	1.24 B$

2.10.2 Hydropower G.S Escalation Rate

Given changes in the economic climate, particularly volatility in commodity prices, skilled labour shortages, overall global economic uncertainty, globalization of the economy, just-in-time inventories, and shortened supply cycles a sophisticated approach to estimating escalation is presently required.

Over the last decade, while relevant commodity prices have shown significant volatility, the overall trend has seen them increase at a rate substantially greater than the CPI. It is not believed that the drivers behind this accelerated price escalation (as highlighted by Hydro) are expected to change. As such KP would employ an aggregate index that would yield a higher escalation; as such Hydro's escalation estimate appears to be underestimated.

2.10.3 Escalation Reserves

2.10.3.1 Manitoba Hydro Definition

"Escalation Reserve: is intended to cover the anticipated additional costs to the project associated with cost escalation greater than Canadian CPI. The reserve is based on the additional costs associated with a standard year-over-year escalation rate of 2.5%, compared to escalation following Canadian CPI. This standard rate was obtained by taking the approximate average escalation rate between the Canadian CPI and a composite escalation rate (or "basket" rate) of commodities typical of a hydroelectric generating station (e.g. steel, cement, construction labour, etc.). The composite escalation rate is developed by combining a number of individual market escalation indices (items such as construction labour, steel, cement, etc.), based on their estimated use in the construction of a generating station, to form a single composite rate."

The Process was illustrated in the repeated in Figure 2.5 below.

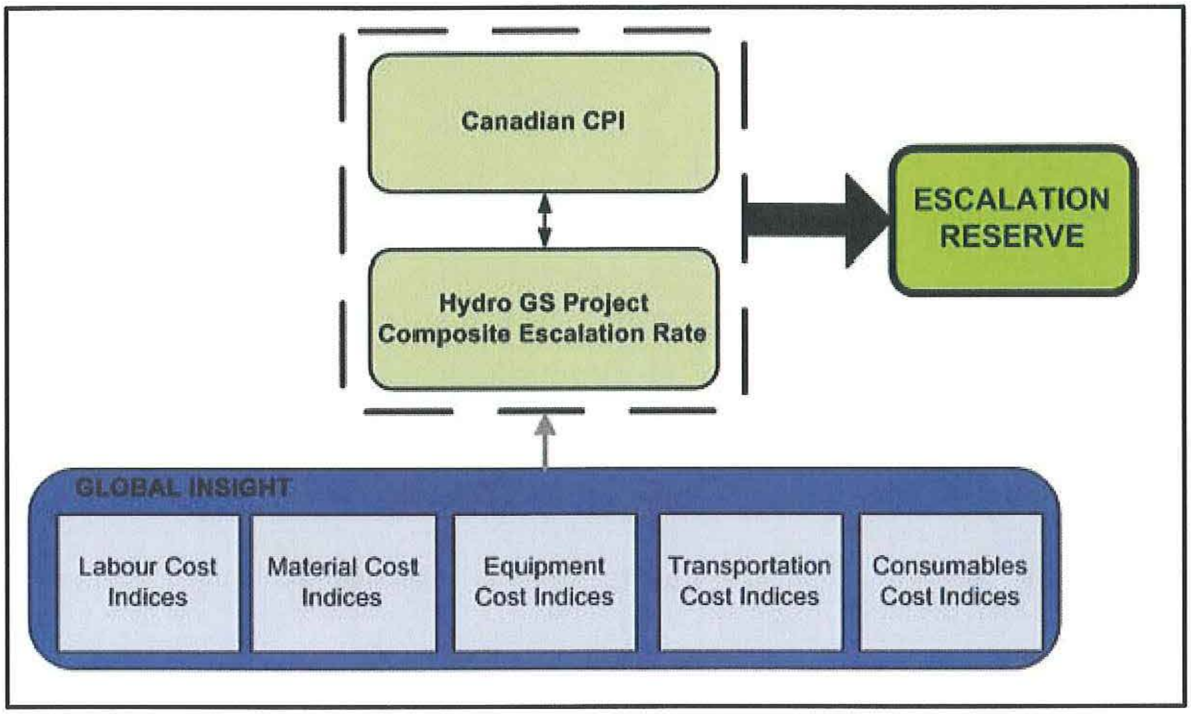


Figure 2.5 Development of the Escalation Reserve

2.10.3.2 Development of the Hydro GS Project Composite Escalation Rate

Hydro has obtained market indices and forecasts for the items that make up the composite escalation rate IHS Global Insight. IHS Global Insight provides comprehensive analysis of economic conditions and business and investment climates and has expertise in all major industries, with special emphasis and dedicated staff providing in-depth coverage in industries including construction, energy, steel and global commerce and transport.

Since the standard rate of 2.5% was the approximate average escalation rate between the Canadian CPI and the "basket" rate, it can be inferred that the "basket" rate is around 3.1%.

In Table 2.11 a rate of 2.5% has been compared to the Muskrat Falls Estimated Escalation rates developed by Nalcor using information by Global Insight. They represent roughly speaking a 3.4% annual escalation rate from 2010 to 2018.

Table 2.11 Comparison of Muskrat Falls Estimated Escalation to 2.5 % Escalation

Year	2010	2011	2012	2013	2014	2015	2016	2017	2018
Muskrat Falls Estimated Escalation [1]	1.00	1.02	1.05	1.11	1.16	1.20	1.23	1.26	1.30
Escalated at 2.5% Annually	1.00	1.03	1.05	1.08	1.10	1.13	1.16	1.19	1.22

NOTES:

1. http://www.pub.nf.ca/applications/MuskratFalls2011/files/exhibits/Exhibit3-Part2-CostEscalation.pdf

2.10.3.3 Composite Escalation Rate vs. Hydro GS Project Composite Escalation Rate

Not only was the Hydro GS Project Composite Escalation Rate not used to determine escalation but it was averaged with CPI to determine the management reserve. Manitoba Hydro did not provide an explanation for why these values were averaged or blended in a more particular ratio. In sum the escalation is less than what a Hydro GS Project Composite Escalation Rate would warrant and the Escalation and the Escalation Reserve combined are less than what the Hydro GS Project Composite Escalation Rate would indicate.

2.10.3.4 The need for contingency on escalation

As expressed by AACE (in RP's 40R-08) escalation and currency effects do not form part of the contingency estimates. Therefore one may want to allow for some measure of the risk and uncertainty to be accounted for as part of the in-service cost escalation estimate.

In CAC/MH I-001, Hydro stated: "The capital cost estimate (including contingency) contains no provision for uncertainty in future construction cost escalation or the potential need for major scope additions resulting from external requirements. The Project Management Reserve could capture these items and they would be added to the estimate. The need for, and quantum of the Project Management Reserve is determined by Manitoba Hydro senior executive."

Even if the cost estimate was escalated at the Hydro GS Project Composite Escalation Rate, it would not include an allowance for the uncertainty around the escalation factor which is believed to be the role of the Escalation management reserve. The determination would depend on the variability around the indices provided by Global Insight.

2.10.3.5 Adequacy of Escalation Reserve

It is not believed that the escalation amount and escalation reserve combined are sufficient to cover the escalation amount based on reasonable assumptions of escalation.

Of the $783 million increase in capital costs for Wuskwatim between the $988 million in CEF03 to $1.771 billion in CEF12, $47 million was attributed by Manitoba Hydro (in 2012/13 and 2013/14 Undertaking # 47, Transcript Page #2263 to the actual escalation in excess of original estimated inflation. In comparison $116 million escalation reserve is allotted to a project expected to cost $6.22 billion. This seems to indicate if a comparable escalation reserve had been put aside for Wuskwatim it would have been insufficient to cover the actual escalation.

Hydro has gone through the process of determining a Hydro GS Project Composite Escalation Rate, a cursory review indicates it is comparable to that used by Nalcor and yet it is not used directly to demine a reasonable level of anticipated escalation nor does it include any margin.

This lead KP to believe in the escalation Reserve is inadequate.

2.11 LABOUR MANAGEMENT RESERVE

Management reserve is intended to address major risk items not addressed through the normal scope of contingency and which magnitude warrants special consideration. In the case of Keeyask and Conawapa the risks not addressed through contingency are related to escalation and labour productivity. Escalation Reserve was discussed in Section 2.10.

Due to largely external factors related to the expected state of the Canadian construction labour market, the potential impact of limited labour availability and the resulting low productivity issues not captured in the P50 contingency in the Base Estimate, Manitoba Hydro has elected to include a Labour reserve. Both labour attraction and labour retention and the associated impacts to productivity are major concerns for Keeyask and Conawapa. The labour reserve represents potential additional costs associated with labour productivity and cumulative impacts.

2.11.1 What Facets of Labour Uncertainty are already covered by the Contingency

The contingency estimate already has some measures and contingency to deal with a degree of the labour availability and productivity issues. Based on what was experienced on Wuskwatim and what is considered within the control of the project team, Hydro listed the following as covered by the contingency estimate on Keeyask and Conawapa:

- Letter Of Agreements on Burntwood Nelson Agreement (BNA) wages
- Increased staff-to-craft ratio for the General Civil Contractor
- High quality camp accommodations
- Cost associated with increased turnarounds for craft workers compared to standard in BNA, and
- Significant adjustment to electrical and mechanical estimated costs.

It is not clear from the disclosure if there are any potential redundancies associated with the Labour Reserve Calculation.

2.11.2 Method

Manitoba Hydro has not disclosed the specifics as to how the Labour Reserve was calculated.

Chapter 15 of the Submission shows:

"The labour risk has been calculated based on a series of correlated and cumulative impacts that together act as a single major event. As a result, it is difficult to say what portion of this risk would apply at different probabilities. "

In essence Hydro has considered the labour risk is similar to a scope change in which, if that scope change occurred, the associated cost would be added to the estimate. The detail of the scenarios considered was not disclosed.

In Appendix 9.3 (p.34) it is stated:
"The labour reserve was derived by applying outcomes of the Wuskwatim process reviews to the labour components of the Keeyask and Conawapa estimates."

CAC/MH I-007 indicates that the Labour reserve for Keeyask was established from:

- Increase to direct and indirect labour costs due to lower than estimated Concrete Productivity
- Schedule - Cumulative Effects of Construction Delays on Critical Path, and
- Additional costs to work 7 days/week, 12 hour shifts on the General Civil Contract.

The specific values attributed to each cost are commercially sensitive and as such MH was not able to provide separate amounts for each item.

2.11.3 Mitigation Strategies

In Chapter 15 of the submission (p. 40), Manitoba Hydro has pointed out that a number of steps have been taken by Manitoba Hydro to mitigate labour risk and avoid drawing from the labour reserve. Some may argue that the High-Quality Construction Camp and Changes to Isolation Leaves and Travel aspects do not have a positive bearing on productivity but have become an actual requirement of doing work in remote location in Canada.

2.11.4 Adequacy of Labour Reserves

In all likelihood the Management Reserve does not represent the worst case scenario of a labour cost increase beyond those observed in the Alberta oil field or the worst of the Wuskwatim productivity rates, as a result it is difficult to determine the adequacy

However at a very high level it does appear in the correct order of magnitude, following this simplistic analysis:

According to information portrayed in the Environmental Impact Assessments and the Economic Models, Wages and Salaries represent very roughly 30% of the generating station costs. The difference between the Horizon Oil Sands Rates and the BNA and LOA Rate is very roughly 20% extra. Applying the total (30%x20%) 6% to the point estimate and contingency totals for Keeyask and Conawapa would result in an overnight 215 M$ for Keeyask and 318 M$ for Keeyask. Multiplying these by 1.4 for Keeyask and 1.7 for Conawapa to allow for escalation and interest would bring these totals to 300 M$ and 550 M$, which are very roughly comparable to the 380 M$ and 510 M$ included Labour Reserve. It is important to highlight that this crude assumption overlaps contingency inclusions and does not consider overall staffing changes or schedule delays included the actual Labour Reserve calculation.

It does lead KP to believe in the adequacy of the Labour Reserve.

2.11.5 Performance Measurement

One aspect of the use of Management Reserves is that it is outside of a system that would allow for Performance Measurement.

2.12 CAPITALIZED INTEREST AND INTEREST ON MH EQUITY

Knight Piésold feels that the calculation and determination of the capitalized interest and interest on MH Equity are better suited for discussions by other Independent Experts. They are included in the In-service Costs.

2.13 MONEY SPENT TO DATE

The money spent to date has been problematic in the review as it is ever evolving and falls outside of a clear project definition that would drive a point estimate.

In response to KP/MH I-015a, Hydro has provided a review of the Keeyask and Conawapa actual expenditures as well as the estimated interest on capital to carry the expenditures forward, as summarized in Table 2.12 It is noted that [redacted] of the Money Spent to Date relates [redacted] of the two facilities.

Table 2.12 Keeyask and Conawapa Actuals to March 2012

	Keeyask Actuals to March 31 2012	Conawapa Actuals to March 31 2012
Licensing and Planning	[redacted]	[redacted]
Infrastructure Upgrade	[redacted]	[redacted]
Generating Station Infrastructure		[redacted]
Generating Station	[redacted]	[redacted]
Transmission	[redacted]	
Interest on Capital	[redacted]	[redacted]
Total Money Spent to Date	[redacted]	[redacted]

Sunk costs were not included in Hydro's economic evaluations as they represented money already spent or commitments that cannot be changed relative to the decision point when choosing among plans. This creates some level of confusion as to what is included and not included in the project definition, and will create more confusion as the Keeyask Infrastructure Project progresses. KP does not recommend this practice as it obfuscates the cost estimate; strictly speaking the cost estimate should be associated with a specific project definition. The Money Spent to Date format also does not allow for an immediate measure of project performance on the money spent to date as compared to the anticipated costs.

2.14 SUMMARY OF CAPITAL COST ESTIMATES

Summary tables of the Total In-Service Cost estimates for the two projects are shown in Table 2.13 and Table 2.14. KP has reviewed a more detailed breakdown of these costs provided in confidence by Manitoba Hydro.

Table 2.13 Summary of Keeyask In-service Cost (CEF 2012)

	CEF 12/IFF12 Cost (Billions of Dollars)	Ratio of In-service Cost	
Point Estimate	3.21	51%	
Contingency	0.53	8%	
Management Reserve	0.50	8%	Base Cost = 4.24 B$
Capitalized Interest	0.88	14%	
Interest on MH Equity	0.20	3%	
Escalation at CPI	0.42	7%	
Money Spent to Date	0.50	8%	
Total In-service Cost	6.24	100%	

Table 2.14 Summary of Conawapa In-service Cost (CEF 2012)

	CEF 12/IFF12 (Billions of Dollars)	Ratio of In-service Cost	
Point Estimate	4.54	45%	Base Cost = 6.14 B$
Contingency	0.75	7%	
Management Reserve	0.85	8%	
Capitalized Interest	2.59	25%	
Interest on MH Equity	NA	NA	
Escalation at CPI	1.24	12%	
Money Spent to Date	0.23	2%	
Total In-service Cost	10.20	100%	

2.15 KEEYASK AND CONAWAPA OPERATIONS AND MAINTENANCE COSTS

2.15.1 Expected O&M Costs

The expected O&M Costs for Keeyask and Conawapa are shown in Table 2.15.

Table 2.15 O&M Costs for Keeyask G.S. and Conawapa G.S.

	Average Lifetime Fixed O&M Cost (2012$)/kW/year	Installed Capacity (MW)	Average Fixed O&M Cost (M 2012$)/year	Source:
Keeyask G.S.	17.86	695	12.4	Appendix 7.2 page 46
Conawapa G.S.	10.28	1,485	15.3	Appendix 7.2 page 56

2.15.2 Breakdown Structure

Operation and maintenance costs of the Keeyask and Conawapa projects were prepared by the Financial Planning (FP) and Resource Planning and Market Analysis (RPMA) groups at Hydro for the Power Planning Division. KP has been provided with a detailed breakdown of the anticipated costs, including fixed costs and costs associated with the upkeep of particular facility components according to their maintenance requirements.

2.15.2.1 Fixed Costs

Wages, salaries and benefits are based on estimated station equivalent full time employment by job classification. This includes salaries, northern allowance, overtime and benefits to which center costs associated with materials, travel, motor vehicles and purchased services are added.

The estimates also include:

- Provisions for employment opportunities and training of staff in Northern Manitoba during the initial operating phase of the GS
- Property and general liability insurance
- Partnership Expenses
- Internal administrative costs not captured elsewhere
- Internal labour, external consulting and internal and external disbursement costs for implementation of the Environmental Monitoring Program support for the Environmental Protection Plan
- Staff house at Conawapa
- Gilliam Services Cost associated with providing accommodations and support infrastructure in the town of Gilliam for Keeyask, and
- An Annual program to address water safety issues associated with affected waterways by collecting floating woody debris and the installation of various navigational marking aids to provide safe travel routes during open water and ice covered periods.

2.15.2.2 Capital Maintenance Costs

Capital Maintenance Costs represent less than 20% of the O&M costs and appear in later years of the life of the projects. Capital maintenance costs include scheduled:

- Upgrades of system controls used for operating and monitoring the turbine generator units and controls
- Inspection and adjustment of winding fastening mechanisms that maintain necessary tolerances
- Replacement of generator windings
- Replacement of turbine runners possibly due to cavitation damage
- Refurbishment of all working components of the intake gates, draft tube stop logs, spillway gates and spillway stop logs, and

The life cycles assumed by Hydro are commensurate with other hydropower projects.

3 – REVIEW OF CONSTRUCTION INDIRECT COSTS

3.1 SCOPE OF WORK

Question 2: "Review and assess Manitoba Hydro's construction indirect costs including access roads, campsites, and off-site mitigation costs for Conawapa GS and Keeyask GS"

3.2 METHODOLOGY

3.2.1 Definition of Indirects

The Point Estimate is made up of items termed Direct and Indirect Costs. Direct Costs of the Keeyask Generating Station Project (KGSP) and the Conawapa Generating Station Project (CGSP) are discussed in Section 2 and Indirect Costs in this section. Indirect costs are defined in Appendix 2.4 (p.5) to include all temporary and permanent items not directly associated with the primary structures but still required to successfully implement the project. Indirect Costs in the context of the final In-Service Cost include site infrastructure, site services, engineering and project management, environment and mitigation, general expenses and First Nation participation payments but excludes the related costs to date (or money spent). Indirect costs form approximately one third of the Point Estimate.

Note on Definitions:

- The Indirect Costs herein specifically exclude Contractor Indirects which are included in the Direct Costs.
- The Indirect Costs herein include Direct and Indirect Costs associated with the Keeyask Infrastructure Project (KIP).

Appendix 2.4 (p. 5) includes a figure breaking up the makeup of the indirect costs as follows:

- Pre-Construction Costs
  - Planning
  - Partnership
  - Licensing
- Site Infrastructure
  - Access Roads
  - Site Development
  - Camp Facilities
  - Sewer and Water systems
  - Temporary Power
- Site Services
  - Catering
  - Security
  - EMS
  - Camp Maintenance
- Engineering and Project Management
  - Site Office Costs
  - Head Office Costs
- Environmental & Mitigation Activities

- Environmental Monitoring Programs
    - Mitigation Costs
    - Adverse Effects
- General Expenses
    - Engineering Consultants
    - Travel Costs
    - Site Office Supplies
    - Insurance
    - General Safety
    - Site Tours, and
    - HPMA.

3.2.2 Project Definition

KP did not come across a clear project definition document inclusive of all indirects akin to the Basis of Cost Estimate reports used in the determination of the direct costs. KP has discussed and been witness to some of the calculations covering the Indirect Costs during teleconferences with Hydro but has not seen any complete references. The KP review would benefit from seeing such comprehensive documents.

3.2.2.1 KIP Project Definition

Hydro is utilizing the services of engineering consulting firms for various design aspects of the KIP. These firms are:

- AECOM, and
- Stantec.

Both these firms are large reputable engineering firms.

The KIP includes:

- The North Access Road to Provincial Road (PR) 280
- The temporary road camp
- The bridge at Looking Back Creek
- The 200 Person Start-up Camp
- The 500 Person Main Camp
- The preparation of Contractor and Manitoba Hydro work areas, and
- The construction power services.

Reminder: The NFAT economic analysis did not consider capital cost estimates associated with the KIP as they are considered sunk costs and common to all development plans.

3.2.2.2 Other Contract Documents

KP has reviewed the Request for Direct Negotiation Proposals or Proposals for:

- The North Access Road - Part A and Part B
- The North Access road Start Up Camp Site Development and Install
- The Design and Supply of Modular Buildings and Related Engineering Services
- The Supply and Installation of Bridge at Look Back Creek

- The Provision for Catering and Janitorial Services for Part 1, 2, and 3
- The Provision of Security Services for Part 1 and Part 2
- The Employee Retention and Support Services for Part 1 and Part 2
- The Provision of Emergency Medical and Ambulance Services for Part 1,
- The Design, Engineering, Manufacturing and Installation of the Construction Camp Facility, and
- The Worksite Area Site Development.

All these requests and proposals include a high level of project definition.

3.2.2.3 Conawapa Infrastructure Details

The Conawapa Project is at Stage 4 of development and although the project has not fully defined required infrastructure for construction, it is assumed MH will also establish separate projects for infrastructure and the generation project. Generally Conawapa support infrastructure includes:

- Access Road
- Portage/ Boat Launch
- Work Areas, and
- Camp.

Construction of Conawapa infrastructure is not scheduled to start until 2016.

3.2.3 Methodology

There are a substantial amount of indirect costs associated with remote mega-projects like Keeyask and Conawapa. The primary contributors of indirect costs are: camp/site infrastructure and services, site and office labour, and licensing costs. The share of indirect costs as a percentage of the total Point Estimate has increased over time. Indirect costs are estimated using various methods and are provided by multiple areas within Hydro. Some indirect costs are developed as first principles estimates, while the majority are based on vendor quotations and/or historical costs. Many of the indirect cost contracts have already been awarded and as such the costs are defined.

3.3 INDIRECT COST BREAKDOWN STRUCTURE

The indirect cost breakdown structure provided to KP is as follows (it did not match in all points the breakdown in Figure 3 of Appendix 2.4):

- Studies and Investigations
- Environmental & Mitigation
- Update to Licensing
- Construction Power
- Infrastructure
- Service Contracts
- MH Office and Labour
- Expenses & External Groups
- Environmental & Mitigation
- Labour and Material Provisions
- Training and Partnerships
- Preferentials, and

- Escalation to Fiscal Year.

3.4 INDIRECT COST BREAKDOWN

Tables 3.1 and 3.2 give Hydro's breakdown of the Indirect Costs. Note that this is prior to a change in the approach to contingency whereby contingency on Directs and Indirects were integrated into a single value.

Table 3.1 2009 Indirect Costs for Keeyask

Description	Total Point Estimate (M$)
Studies & Investigations	[redacted]
Environmental & Mitigation	[redacted]
Construction Power	[redacted]
Infrastructure	[redacted]
KIP	[redacted]
Service Contracts	[redacted]
MH Office and Labour	[redacted]
Expenses & External Groups	[redacted]
Labour and Material Provisions	[redacted]
Total Indirects without Contingency	[redacted]

Table 3.2 2010 Indirect Costs for Conawapa

Description	Total Estimate (M$)
Studies & Investigations	[redacted]
Environmental Items	[redacted]
Mitigation Items	[redacted]
Electrical Power & Communications	[redacted]
Roads & rail	[redacted]
Construction Camp Infrastructure	[redacted]
Service Contracts	[redacted]
MH Office & Site Labour	[redacted]
Expenses & External Groups	[redacted]
Labour & Material Provisions / Training & Partnership Costs	[redacted]
Total Indirects without Contingency:	[redacted]

4 – CONSTRUCTION MANAGEMENT, SCHEDULE AND CONTRACTING FOR KEEYASK AND CONAWAPA

4.1 SCOPE OF WORK

Question 3: "Review and assess Manitoba Hydro's construction management, schedule, and contracting plans for the design, engineering, procurement, construction, start up, commissioning, testing, and commercial operation of Conawapa GS and Keeyask GS"

4.2 IMPLEMENTATION OF THE PREFERRED DEVELOPMENT PLAN

Chapter 15 of the submission describes some of Hydro's approach to undertaking the Preferred Development Plan and managing the associated development risks. Management of these risks extend to construction management (including labour availability), the development schedule, and the contracting plans. The Cost Estimating Basis includes a breakdown of the contracting plans. As Keeyask is in the forefront of the Preferred Development Plan, more material is available detailing the implementation process for this project.

4.3 GENERAL ROLES AND RESPONSIBILITIES

4.3.1 Owner

In general an owner's role is to provide the overall direction and governance on a project. The Owner also has responsibility for overall performance of the project. Specific areas of project responsibility include: financial, regulatory, environmental, and stakeholder management.

KP does not believe that the systemic risks associated with the ownership structure, if any, can be out right identified or been incorporated into the project contingency. For example if projects delays occur due to decision delays associated of disagreement amongst Partnership members.

4.3.1.1 Keeyask Ownership Structure

While Hydro will purchase all energy produced at the Keeyask Generating Station, the Keeyask Hydropower Limited Partnership ("the Partnership") is the owner of the generation and infrastructure projects under terms outlined in the Joint Keeyask Development Agreement (JKDA) signed in 2009 by Manitoba Hydro and each of the four Keeyask Cree Nations. The management ownership roles of the overall project between Hydro and the Partnership have not been reviewed by KP.

Hydro will own and operate the Keeyask Outlet Transmission Project.

4.3.1.2 Conawapa Ownership Structure

The ownership structure for the Conawapa generation project has not been finalized, but Hydro has committed to providing early involvement and extensive consultations with First Nations in planning the project and providing a forum for addressing community issues and concerns. As with Wuskwatim and the proposed Keeyask Project, the focus of any benefits will be on income, training, employment and business opportunities providing opportunities for First Nations in the vicinity of the project to participate in the environmental assessment, monitoring, construction, and governance of the project.

Manitoba Hydro will own and operate the Conawapa Transmission Outlet Project.

4.3.2 Project Manager and Construction Manager

Hydro will act as the Project Manager and the Construction Manager in a role distinct from that of the Owner. In the envisaged strategy, the general partners will contract all the planning, construction and operation of the project to Hydro, and will contract with Hydro to provide all the debt financing required to construct the project.

The Project Manager and Construction Manager are responsible for the overall project costs, schedule and quality. Hydro will subcontract a majority of the services and supplies required to actually build the projects. Hydro intends to form separate contracts with the various contractors and has overall responsibility for interface management.

KP identifies interface management by Manitoba Hydro as one of the most important systemic risks associated with the implementation of the preferred development plan. KP has not been able to fully ascertain that these risks have been adequately captured in the Contingency calculation. In this regard, the Keeyask Project Risk Register did provide a measure of the costs associated with Hydro going to outside consultant resources to support Hydro in performing Construction Management.

KP further believes that alternate contracting strategies (e.g. LS contracts or PPPs) could reduce these risks but is well aware that these contracting strategies would result in higher direct costs.

4.3.3 Design Engineer

A single project designer is responsible for the majority of the project design. The selected design team is led by Hatch and includes SNC Lavalin and KGS ACRES. Internal Hydro resources provide design and define performance specifications for some of the specialized EPC contracts. The Design Engineer also plays a support role during construction. This strategy is similar to that employed by other Canadian Crown Corporations and is deemed suitable by KP for these projects.

4.3.4 Contractors and Vendors

Contractors and Vendors (GCC, T and G Contractor, etc.) are to carry out the actual construction and supply of equipment. Each contractor manages their own work with overall coordination between contractors to be managed Manitoba Hydro.

4.4 PROJECT EXECUTION PLAN

4.4.1 The Documented Plan

The New Generation Construction Division of Hydro has outlined a Project Execution Plan for the Keeyask Project. The draft document seen by KP acts as a high-level guideline to manage the KIP and the KGSP.

The document:

- Is a guideline of the means, methods, tools and techniques used by Hydro to manage the KIP and the KGSP,
- Serves as a record of the planning effort undertaken by the Hydro New Generation Construction Division (NGC) for the construction phase of the project, and

- Serves as a resource for staff to ensure the project is managed consistently.

KP is able to see that Hydro is following a specific overall process despite the Project Execution Plan presently being in draft form only.

4.4.2 Early Contractor Involvement Process

The General Civil Contract for the KGSP is to be executed using an Early Contractor Involvement (ECI) Process that is to begin imminently with the selection of the General Civil Contractor. The civil contractor involvement in the process two years before major construction begins offers the opportunity to:

- Ensure the contractor construction knowledge is incorporated into the design;
- Refine the delivery schedule;
- Secure the necessary labour; and
- Form alliances with Manitoba suppliers and sub-contractors.

According to Chapter 15 of the NFAT Submission (p.30): "To help reduce scheduling risk and potential interface issues, a number of contracts will be bundled with the GCC, including the Electrical and Mechanical Contract and excavation, cofferdams and draft tube forms. The reduction of interface risk was a lesson learned from the Wuskwatim project, which had several different contracts." To KP this approach is sound in principle, but KP has not investigated in detail which elements were to be addressed in the existing estimate and whether the relevant associated overhead was included in the cost estimate.

4.5 PROJECT MANAGEMENT AND CONSTRUCTION MANAGEMENT PROCEDURES

4.5.1 Developing Project and Construction Management Expertise within Manitoba Hydro

Hydro continues to develop in-house project and construction management expertise through work on the Wuskwatim, Pointe du Bois, Bi-Pole III and other on-going projects. The continual development of project and construction management expertise within Hydro has been identified as a critical success factor for the Keeyask project delivery strategy.

4.5.2 Manitoba Hydro Corporate Policies

The Project Execution Plan refers to a number of existing NGC corporate policies and standards, namely:

- Total Cost and Schedule Management (TCSM) Standard
- Monitor and Control of Engineering Consultants Standard
- Preparation of Project Dashboards and Trend Analysis Standard
- Project Change Authorization (PCA) Process
- Work Package Change Management - Project Change Authorization Process
- Consultant Communication Plans
- Division Plan for Managing the Consultants, and
- Engineering Work Package Scope Sheets (EWPSS).

Hydro has put a great deal of effort into developing project management and construction standards and processes but it is difficult to ascertain how efficiently these will be carried forward in practice.

During the teleconferences with NGC, KP has had an opportunity to look at some of these processes, as they were shown on the Hydro internal SharePoint System. More specifically KP has reviewed the NGC Procedures related to Risk Management and Project Contingency Management (Confidential Information.)

KP followed through the Risk Management Procedure Review with a Review of the Risk Register developed for the Keeyask Project, which demonstrated a level of follow-through on the procedure.

Maintaining Hydro staff will be critical to the maintenance and application of these developed standards.

4.6 CONTRACTING METHODS CONSIDERED

4.6.1 Fixed-Price Contract (FPC)

In a FPC, a contractor is paid a fixed amount regardless of actual costs. Such contracts go by such names as Engineer, Procure and Construct (EPC), Design-Build (DBC) or Lump Sum (LSC). They can be negotiated or competitively bid.

4.6.2 Cost Reimbursable Contract (CRC)

When reservations around contract performance do not allow costs to be estimated with sufficient accuracy to use a fixed-price contract, CRCs can be used. A CRC is one where a contractor is paid for all of its allowed expenses, usually to a set limit, plus additional payment to allow for a profit. A target price for the project is agreed through a negotiation or a tendering process.

The significance of specifying this type of contract, for the current estimate, is to recognize the conditions under which a realistic contractor's profit may be anticipated. For purposes of the current estimate, a specific profit was assumed for the General Civil Works Contract.

By assuming a reimbursable contract, as was implemented at Wuskwatim, Hydro presumes it will be accepting some of the cost risks in return for a contractor's lower but more stable profit margin.

4.6.3 Direct Negotiated Contract (DNC)

Specific DNCs have been entered into because of a preference by Hydro for particular contractors to undertake a specific work assignment. Hydro draws experience with this type of contracts from the Wuskwatim project, which had a number of DNC contracts. Since these contracts are not competitively bid, their value is closely related to the leverage held by Hydro and the diligence associated with the negotiation.

4.6.4 Unit Price Contract (UPC)

A UPC contract is one in which prices or rates are bid by the Contractor for each item of work laid out in a Schedule or Bill of Quantities. The schedule contains estimates of quantities provided by the Owner/Engineer for each item of work and the Tender Price is an aggregation of the products of the Owner/Engineer quantities and the Contractor's bid prices or rates. This is a traditional and well tested form of contract that fairly apportions risk and should result in an equitable outcome for both the Owner and the Engineer. The major downfall is that it does not allow contractor input to the design, thus voiding the opportunity to benefit from his construction experience.

4.6.5 Supply Only Contracts

In the instances were equipment is directly purchased by Hydro with supply only contracts (such as with the electrical equipment contracts), there is no assumed profit and overhead applied to the quoted price.

4.7 CONTRACTING STRATEGIES APPLIED

4.7.1 Contracting Assumptions

The approach to contract packaging for the KGSP and CGSP is similar to that undertaken by Hydro on the Wuskwatim project, and to some extent the previous Lower Nelson River projects. A list of the contracts associated with direct costs is shown in Table 4.1.

Table 4.1 Contract Type for Direct Cost Components

	Keeyask	Conawapa
Civil		
G.S.- General Civil Contract (subcontract assumptions apply)	CRC	L.S./U.P.
Limestone Quarry and Crusher and Haul		DNC
Stage I Coffer Dam	CRC	
Clearing Contract	DNC	
Forebay Clearing Contract		DNC
Forebay Improvement Contract	DNC	
Architectural and Painting Works	DNC	DNC
Ice Boom Contract	LS	
Electrical and Mechanical Contracts		
Major Mechanical Equipment Supply and Installation Contracts	LS	LS
Major Electrical Equipment Supply Contracts	LS	LS
Mechanical and Electrical Supply and Installation Contracts (subcontract assumptions apply)	LS	LS

4.7.2 Special Considerations

In contrast to previous projects on the Lower Nelson River, the General Civil Contractor for Keeyask and Conawapa will be required to provide cement and reinforcing steel.

An EPC model has been selected for the turbine and generators contract, with the contractor being responsible for design, manufacturing and installation. The performance specification is defined by

Hydro's design team. KP has reviewed the Turbine Generator tender documents for Keeyask and found them to conform to expectations and standards.

4.7.3 Existing Contracts

As of September, 2013, 29% of the 2012 $3.05 billion Point Estimate has been covered by contracts that have already been awarded. KP has been given some details of the various contracts (including copies of some of the actual contract documents) but this information is not all embracing and KP is presently unable to offer a comprehensive critique of actual versus budgeted capital costs, particularly with respect to contracts under the general heading of "infrastructure". KP anticipates that they will be able to make progress with this comparison when they receive answers to IR KP/MH II-027 and hold further discussions with Hydro (in pursuit of the addendum to the original appointment by the PUB).

4.8 SCHEDULE

The Preferred Development Plan includes an implementation schedule containing decision points. Schedules are also provided in the Basis of Cost Estimate documents. The schedules are consistent with the described developments and the anticipated work breakdown structures. They are not excessively aggressive and reflect are reasonable in the context of anticipated peak staffing requirements.

A more detailed and complete schedule for Keeyask was included with the Tender Package for the Keeyask General Civil Contract. The recent tenders submitted as part of this contract should validate the feasibility and reasonableness of the construction schedule.

The review of the provided schedule did not allow the ability to ascertain the slack if any left in the scheduling process to cover Hydro's process and procedures or any external owner requirements, such as reviews by themselves or independent engineers.

The Project Execution Plan for Keeyask states that the execution will follow the Hydro Cost and Schedule Standard (CSS) for schedule management.

4.9 KEEYASK GENERAL CIVIL CONTRACT (GCC) TENDERS

The Keeyask GCC is the largest contract on the Keeyask Project and is made up of a range of work packages including excavation, cofferdam construction, river management, dams, dykes, and electrical and mechanical works, as well as construction of the powerhouse and spillway structures.

It is KPs opinion that the Keeyask GCC tenders submitted to Hydro in December 2013 should serve as an important endorsement or otherwise of Hydro's construction management plan, schedule and contracting strategy. Most of all, KP believes that a review of these tenders will offer a lot more certainty and validation of the cost estimates. The review of these tenders was not previously considered as part of the NFAT process but is included in the recently awarded addendum to KP's scope.

In addition to the cost estimate, the tenders should offer [redacted] experienced major general civil contractors perspectives and buy-in of:

- The process selected by Hydro;
- The construction method and sequencing selected, including the package breakdowns selected;

- The construction timing, duration and diversion schedule considered;
- The material quantities estimated;
- The contractors ability to staff the construction under the constraints of the labour agreement terms (including the BNA)

In addition the contractors may offer innovative approaches to the construction not previously considered by Hydro or their Engineers.

5 – WIND, GAS AND SOLAR CAPITAL AND O&M COSTS

5.1 SCOPE OF WORK

Question 4: "Review and assess Manitoba Hydro's capital cost and O&M cost estimates for wind, natural gas combined cycle gas turbines, and solar facilities."

5.2 INDEPENDENT EXPERT ASSESSMENT APPROACH

Hydro has considered development scenarios that consider either wind or natural gas energy either in combination with hydropower, or without hydropower. For this reason, a reasonable level of confidence in the assumptions made by Hydro is required to provide an accurate portrayal of levelised cost of energy for future development scenarios. In developing their cost estimates for purposes of the NFAT, Hydro sought the input of two engineering consultants who specialise in wind energy and natural gas energy respectively. These two consultants are considered sufficiently experienced in the respective technologies that a reasonable level of accuracy from their reports would be anticipated. In order to verify whether the assumed costs are within the expected cost range, Knight Piésold reviewed publically available energy project reports from the past five years (2008-2013). These reports were viewed in comparison to the Hydro assumptions to determine whether any market or geographic trends may justify any adjustments to the NFAT costs. Knight Piésold did not undertake any independent cost modelling as a literature review was deemed sufficient given the current level of planning of both wind and natural gas facilities in Manitoba. Solar PV facilities were not included in any of the NFAT development plans, so the accuracy of the cost assumptions are not expected to be as critical. Nonetheless, the Manitoba PUB requested that KP review the capital and O&M costs for solar facilities. As for the natural gas and wind facilities, the assessment was undertaken through a review of the relevant literature.

5.3 WIND

5.3.1 Wind Energy Consultant's Report

Hydro engaged the services of GL Garrad Hassan (GL GH) to prepare a comprehensive design report on a potential "generic" wind farm of 150 MW to be installed in Manitoba. GL GH are an engineering consultant experienced in the design and construction of wind energy projects in North America and worldwide. Their report was undertaken in order to perform an evaluation of typical capital and operating costs for a wind farm that could be installed in southern Manitoba. This report was provided to KP in confidence, and so a short summary is provided below for the benefit of the readers of the current report.

A generic project was assumed in the GL GH report, with "standard" specifications and no major engineering challenges on site. In addition, the actual lengths of roads, cable trenches, and other site specific aspects were assumed based on "average" conditions. While these are likely subject to variation based on actual site conditions, the report also identified that the wind turbine/generator units may be approximately 75% of the total costs, and this cost assumes that the turbines use a cold weather package to suit Manitoba conditions (although a preferred turbine supplier has not been identified). Cost estimate for the turbine/generator units does not include a contingency, due to the relative certainty around wind turbine costs, with a 10-15% contingency carried on the Balance of Plant items only. In addition, there has been a reported slight reduction in turbine costs since the GL

GH report was written in 2011 (US DoE, 2013). Transmission line, interconnection and power compensation costs have not been included in the GL GH report, as these are assumed to be the responsibility of Hydro. GL GH indicated that they assumed costs based on their experience with similar projects in the prairies - given their level of experience wind energy projects, we expect that their cost estimate could be considered a Class 4 estimate based on the AACE cost estimating methodology.

The report also undertook a detailed assessment of currently available wind turbine technology and a preliminary assessment of the cost/benefit of installing taller turbine towers. While the taller tower may increase energy generation potential it comes at an increased cost, and would need to be considered further during project development. This was not considered in Hydro's assessment of project costs.

The wind energy assessment report compiled operating expenditure (OPEX) data based on 65 operating wind farms in North America. These were sorted by project installed capacity to determine estimate for OPEX for a project on a kWh basis. It is expected that there is a wide variation in O&M costs, and the level of preventive maintenance performed by the owner has a big impact on expected O&M cost through equipment downtime prevention. OPEX costs do not include turbine warranty fees (which cover maintenance for the warranty period), as these are usually included in the turbine supply contract. Sometimes the owner may choose to carry out maintenance directly to reduce costs, but having the Original Equipment Manufacturer (OEM) carry these costs can reduce maintenance and downtime risk. Costs were provided for scheduled maintenance only, with unscheduled maintenance (and downtime) excluded.

5.3.2 Capital Costs

Hydro considered a 65 MW "generic" wind farm for planning purposes in the NFAT, although information on a comparison 100 MW wind farm is also provided in Appendix 7.2 of the NFAT, the 65 MW facility is used for comparison and planning purposes in Manitoba Hydro's assessment. A wind farm size of 65 MW may be smaller than the current approximate average utility scale wind farm in North America, however little difference is reported in the approximate economies of scale between a wind farm of 65 MW and larger projects (US DoE, 2013). The NFAT report provides an approximate cost of $2,400/kW installed capital costs for the generic wind farm, which approximates to $156 million for the 65 MW wind farm ($2012). This results in a cost in 2014 dollar of $163 million as indicated on page 34 of Chapter 7 of the NFAT.

Hydro provided Knight Piésold with confidential explanatory documentation to outline the basis for their capital cost estimate. Manitoba Hydro primarily used a technical update report prepared by the Electrical Power Research Institute (EPRI). This report provided installation costs of wind farms in a number of locations in the United States in 2012, with the site in Michigan considered by Hydro to be most analogous to the expected installation costs in Manitoba. Their explanation indicated that a wind farm cost of [redacted]/kW is inclusive of transmission line upgrades, with a cost of [redacted] without transmission upgrades. A discrepancy was noticed by KP on page 333 of Appendix 7.2 of the NFAT where a cost of $2,400/kW "without transmission" whereas this should be the cost "with transmission". The cost basis used by Hydro compares [redacted] for their "base case" estimate for a 150 MW wind farm in southern

Manitoba (excluding transmission). Hydro indicated that they used the EPRI data to provide a more detailed cash-flow breakdown for the project development than was available from the GL GH report.

A number of independent industry studies were assessed by Knight Piésold in an attempt to corroborate the capital cost basis for potential wind energy projects. These studies have summarised wind energy project costs in North America in recent years and are considered to be reasonable basis for determining how realistic the Manitoba Hydro cost basis is in comparison to costs that would be expected for the actual construction of a wind project in the province. The Hydro base cost compares with the average project cost across the US of approximately $2,100 across the US in 2011 (NREL, 2013) and $2,000 in 2012 (US DoE, 2013). For projects above approximately 50 MW installed in 2012, the approximately cost is $1,900/kW, with little economy of scale benefit for larger projects (US DoE, 2013). A downward cost trend has occurred in recent years after a period of increasing project costs over the previous decade (). This downward trend is expected to be due to ongoing wind turbine cost reductions (US DoE, 2013) as turbine costs have fallen approximately 20-25% worldwide from 2008 to 2012 (REN21, 2013a). While we do not doubt the voracity of the GL GH report as being applicable for the time it was written, considering the downward cost trend, data sources can quickly become out of date, and thus we consider that the GL GH report may not be reflective of current costs in Manitoba. In addition, we consider the EPRI report reviewed by Manitoba Hydro to be less reflective of current costs than the more comprehensive DoE report which reported on a database of 118 projects installed in 2012, representing 72% of the capacity installed in that year (US DoE, 2013). This report indicates an approximately 15% reduction in project costs from in the last two years. By comparing the anticipated onshore wind costs between two Energy Information Administration reports, we see an approximately 13% reduction in project costs between 2009 (US EIA, 2010) and 2012 (US EIA, 2013). This does not correspond directly with the timeframe between the GL GH report and Hydro's cost basis, and is not based on as comprehensive an information source at the DoE report, but nevertheless corroborates the industry average cost reduction in wind project costs in recent years. On this basis, applying a [redacted] to the cost provided in the GL GH report would indicate an approximate "base case" of $1,800/kW (excluding transmission) for the 65 MW wind project in Manitoba.

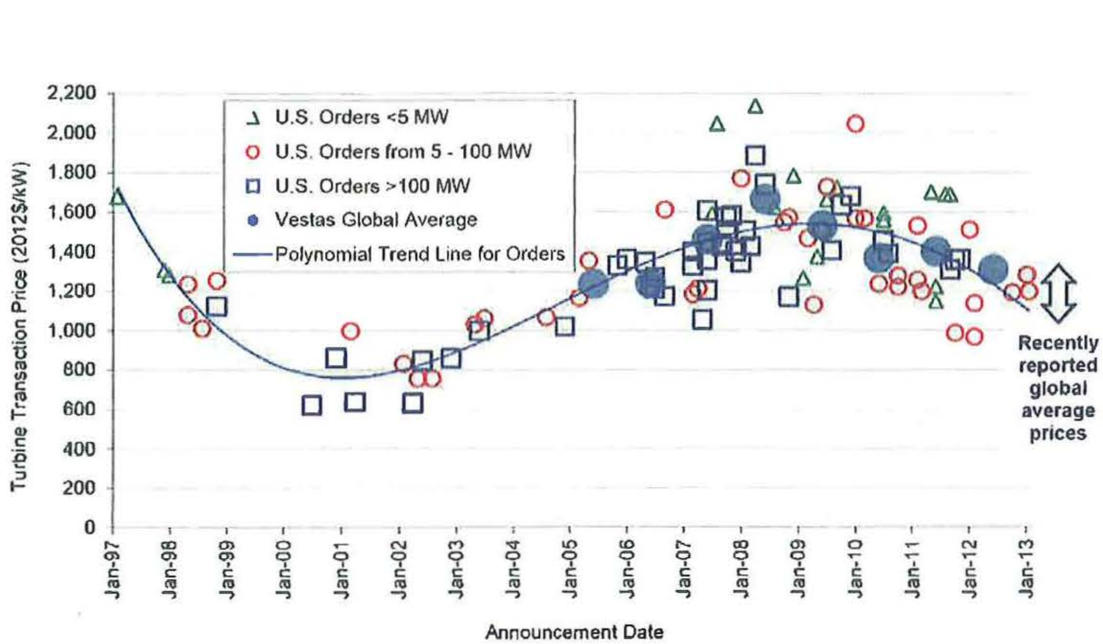


Figure 5.1 Wind Energy Project Cost Trends (US DoE, 2013).

It is apparent that project costs may differ by locality, with the "Interior" region of the US (adjacent to Manitoba) reporting average project costs of approximately $1760/kW and the lowest overall spread in costs (US DoE, 2013). Regional differences may be due to local transportation costs, siting and permitting requirements, constructability issues and types of turbine deployed in different regions. While there may be differences due to local environmental regulations, labour costs or other considerations between Minnesota, North Dakota and Southern Manitoba, these US States should nevertheless be considered the closest geographical comparison to Manitoba. On this basis, the expected "base case" capital costs rounded to the nearest $100/kW would be approximately $1,800/kW, which corresponds to the cost obtained by applying the expected [redacted] to reflect market changes since the GL GH report was written. Furthermore, there is some optimism among wind energy experts that further technological advances and cost reductions are possible (REN21, 2013b; IPCC, 2012). Considering this likelihood, and the fact that the data is based on projects installed in 2012 (that is, data that is already out of date), a base cost of $1,800/kW should be considered conservative.

While Hydro indicated in their explanatory documentation that they used an EPRI technical summary report as the basis for their capital cost estimate, we believe that the comprehensive report prepared by GL GH justifies use of a narrower accuracy range for the cost estimate (albeit that we recommend discounting the GL GH cost to reflect recent cost reductions). Hydro have indicated that they are considering wind to be a "Stage 1 – Inventory" resource. However, given the extensive experience in wind project development of GL GH, and the level of detail provided in their report, we would consider that the 65 MW wind farm may be considered "Stage 2 – Feasibility" or between Stage 1 and Stage 2. We suggest that the consideration of wind as a "Stage 1" resource, coupled with the AACE Class 5 estimate range (-50% to +100%) may result in a higher degree of uncertainty in the cost estimate than is likely to be the case. Assessing the variation in wind project costs in 2012 shows a maximum range of approximately -30% to +50% in the "Interior" region of the US (nearest to Manitoba), and approximately -25% to +30% for projects in the 50-100 MW capacity range (US DoE, 2013). This includes the lowest and highest outliers, and most projects seem to fall within a smaller cost range – although the DoE report does not provide the raw data, so an actual cost distribution cannot be determined. Based on the foregoing, a maximum cost estimate accuracy range of approximately -20% to +25% may be appropriate for wind energy planning.

5.3.3 Wind Capital Cost Conclusion

The NFAT assessment could consider a wind energy base cost of $1,800/kW for a total base cost of $117 million (excluding transmission) for the 65 MW wind energy projects, with a maximum cost accuracy range of -20% to +25%. This should be recognised as a conservative estimate, with continued cost reductions in the immediate future for wind energy projects considered likely.

Hydro should regularly review their long term development plan with respect to wind energy capital costs, as further cost reductions for wind energy will reduce the levelised cost of energy for wind energy, and likely make it a more cost effective energy resource if cost reductions continue.

5.3.4 Operation and Maintenance Costs

Hydro indicated in a confidential summary to Knight Piésold that their operating cost estimate was based on a report provided by the Energy Information Administration (EIA), and used a base cost of $39.55/kW per year. This report identified operating cost of approximately $39.55 for a "generic" wind farm in 2012 (US EIA, 2013). In comparison, the GL GH report prepared for Hydro provided a summary of 65 operating projects and found an approximate operating cost range of [redacted]/kW-year. Hydro also included a comparison to an Electric Power Research Institute (EPRI) technology guide ($2011). This indicated a range of approximately [redacted]/kW-year for 8 wind energy projects. Knight Piésold reviewed a US Department of Energy report indicating a range of operating costs of less than $5/MWh to over $20/MWh in 2012 and an average of approximately $10/MWh (US DoE, 2013). This equates to approximately $17 - $70/kW-year for a 40% capacity factor project and an average of approximately $34/kW-year. Other sources provide O&M cost estimates of $35/kW-year (NREL, 2013), $50/kW-year (E3, 2010) and $60/kW-year (Black and Veatch, 2012) . It is apparent that there is a wide variation in reported O&M costs for a wind energy project, and there is expected to be a great deal of uncertainty until a project is built and O&M contracts are set (although uncertainty around unscheduled outages remains). On the basis of the studies that were assessed, it does not appear that that the O&M costs for wind are outside of the range of expected O&M costs, however a wide range of reported costs are apparent.

5.3.5 Wind O&M Cost Conclusion

Use of an anticipated O&M cost for wind projects of $39.55/kW-year is appropriate, but sensitivity analysis should be carried out on O&M costs ranging from at least $35-$55 should be assessed in the development plan to determine the impact of much of the reported range of O&M costs for wind projects.

5.4 NATURAL GAS

5.4.1 Natural Gas-Fired Technology – Consultant's Report

A study of natural gas fired power generation technologies leading to recommendations on the generation technology options suitable to meet the requirements of a number of generation system development plans was prepared for Hydro by Gryphon International Engineering Services, Inc. (Gryphon), an engineering consultant experienced in the design and implementation of natural gas-fired power technologies. This report was provided in confidence to Knight Piésold and so a short review summary is provided below.

Gryphon reviewed the state of available gas turbine technology, including the offerings by major gas turbine equipment suppliers (GE, Rolls-Royce, Alstom, Pratt and Whitney, Siemens and Mitsubishi). Three broad technology types were considered including Combined Cycle Gas Turbine (CCGT) industrial style Simple Cycle Gas Turbine (SCGT) and aeroderivative SCGT. Aeroderivative turbines are based on aircraft engines, and are thus lightweight and able to respond quickly to variations in electrical demand. Industrial style SCGT units are heavier gas turbines developed specifically for industrial applications and are a cheaper but slightly slower to respond than aeroderivative units. Nonetheless, they are still well suited to peak load applications. Gas turbines can adopt CCGT technology to provide a more efficient system better suited to base load and intermediate load applications, by providing a heat recovery steam generator and steam turbine generator in lieu of discharging the hot exhaust gases from the gas turbine directly to the atmosphere. The summary of the current technology offerings provided by Gryphon is comprehensive and covers a broad range of the gas turbine market. For the purposes of cost estimates, the preferred GE units were used for each of the three options. The GE models chosen for the units were for CCGT – GE 7FA.05 (complete with steam generator and steam turbine), industrial type SCGT – GE 7FA.05 and aeroderivative SCGT – LM6000PH. These units were chosen over the alternatives due to larger fleet size and operating experience compared to units supplied by other suppliers.

The cost estimate for the gas turbine systems was based on output from GTPRO/PEACE software, as well as Gas Turbine World industry trade publication. These are considered "industry standard" resources, and are suitable tools for the current level of investigation. In addition, Gryphon obtained budgetary pricing of the major pieces of equipment from gas turbine suppliers, and recommended obtaining competitive pricing for the entire system at the time of purchase of a gas power plant. Gryphon indicated that the level of detail provided is sufficient for an AACE Class 4 estimate.

5.4.2 Capital Cost

Hydro has indicated an installed overnight capital cost (P_{50}) estimate of $427 million, $170 million and $75 million for the CCGT, industrial SCGT and aeroderivative SCGT respectively ($2014). Based on an installed project capacity of 308 MW, 209 MW and 47 MW, these costs equate to $1.30 million/MW, $0.77 million/MW and $1.51 million/MW respectively. These correspond approximately to the costs identified in the Natural Gas Technologies study by Gryphon, with the exclusion of the 20% contingency applied by Gryphon.

A number of independent industry studies were assessed by Knight Piésold in an attempt to corroborate the capital cost basis for potential natural gas power projects. These studies consist of either summaries of actual construction costs for projects that been built, or estimates for "generic" projects that have sought current industry-standard pricing for major components and materials, in a similar manner to the report prepared by Gryphon for Hydro. Reports that were assessed by Knight Piésold to corroborate the NFAT natural gas cost basis included the BC Hydro resource options update (BC Hydro, 2013), the Energy Information Administration report on capital costs for utility scale generating facilities (US EIA, 2013), a Congressional Research Service report prepared for the US Congress (Kaplan, 2008) and a cost report on multiple energy technologies (Black and Veatch, 2012). The data from these sources were compiled to provide a check on the legitimacy of the costs used in the NFAT.

No cost trend with respect to time was identified in the data assessed for the CCGT units, so grouping of the data based on the five year period (adjusted for CPI) was assumed to be valid for the current high-level assessment of the costs proposed for the NFAT. A total of 15 data points were available for comparison to the CCGT costs used by Hydro for the NFAT (Figure 5.2). The data indicate that there may be a slight economy of scale effect for larger combined cycle projects, although the data are insufficient to draw definitive conclusions. A further five data points were available for which CCGT capacity was not provided; combining with the 15 data points provided in Figure 5.2 yields a median project cost of $1.24 million/MW and an interquartile range of approximately $1.16-$1.35 million/MW. On the basis of the data available, there is no indication that the $1.3 million/MW (in 2014$) chosen for the NFAT assessment is outside of the expected range of costs for a potential CCGT facility.

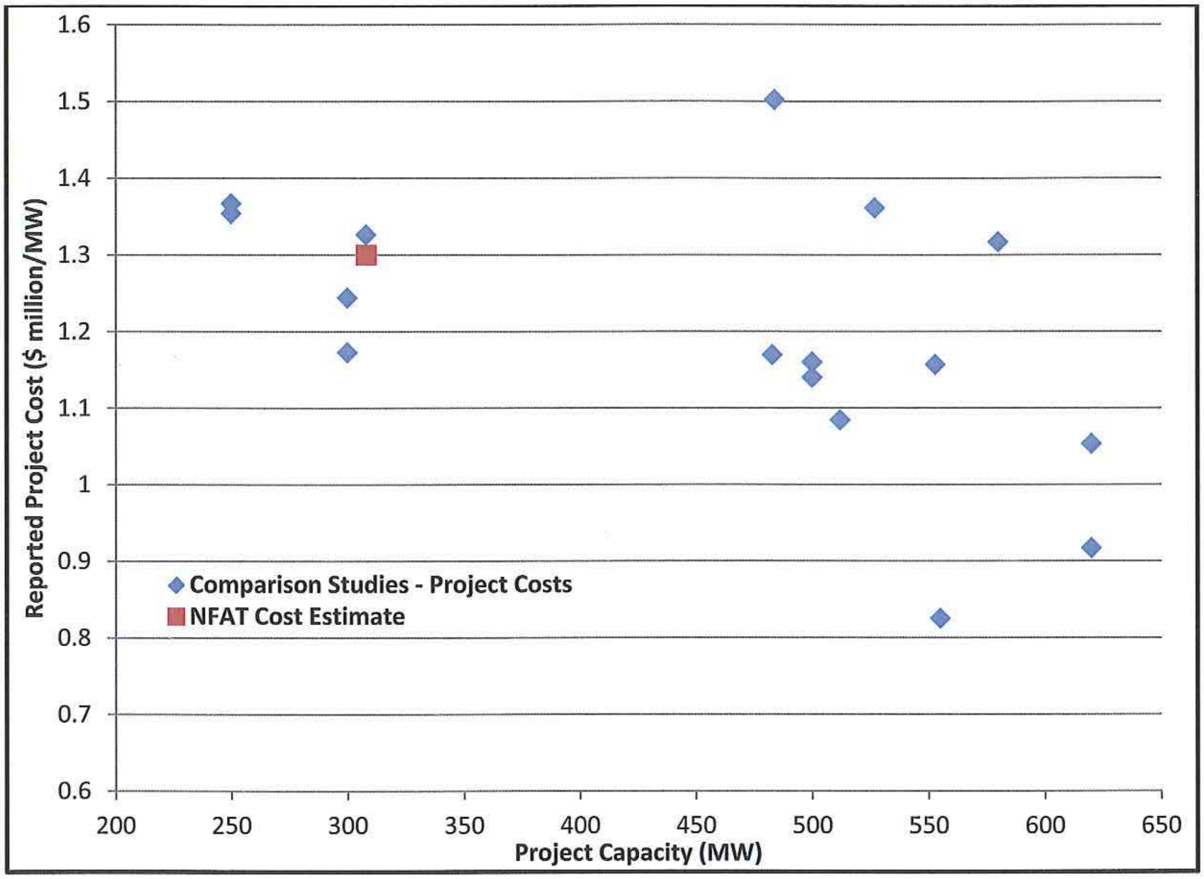


Figure 5.2 Comparison of Reported Combined Cycle Gas Turbine Capital Costs (adjusted to $2012) and the Cost Estimate Assumed by Manitoba Hydro for the NFAT (Kaplan, 2008; US EIA, 2010; E3, 2010; Black and Veatch, 2012; BC Hydro, 2013; NETL, 2013; US EIA, 2013).

For the SCGT facilities, fewer data points were available than for the CCGT facilities. A total of six data points were available, with a range of $0.68-$1.06 million/MW. The median of these six project costs was approximately $0.7 million/MW. For the aeroderivative units, costs between $0.86-1.48 million/MW. These costs are lower than the $1.51 million/MW assumed for the NFAT, however use of the larger 93 MW aeroderivative facility (cost of $126 million, excluding contingency) results in an installed cost of capacity of $1.36 million/MW. The capital costs assumed for the NFAT for the SCGT facilities is within the range of expected value based on the publically available studies that were examined. Due to the smaller dataset available for SCGT facilities than for the CCGT facilities, the confidence level of the comparison data for the SCGT facilities is lower.

Geographic variations in natural gas project costs have been reported (US EIA, 2010; US EIA, 2013), however we have not drawn conclusions from these data, as the two nearest US states to Manitoba show both a higher than average cost (Minnesota) and an approximately equal lower than average cost (North Dakota). Unlike the broader geographic regions identified for wind energy (US DoE, 2013), KP do not recommend application of the more localised (city-specific) geographic data available for natural gas projects in the US EIA reports to the situation in Manitoba.

Hydro have indicated that they consider natural gas to be a "Stage 2 – Feasibility" level resource, which appears appropriate given the level of detail provided in the consultant report to Hydro for natural gas technology. Based on this classification, the AACE cost estimate suggests an accuracy range between -15% to -30% on the low end and +20% to +50% at the high end. Given the narrow cost range reported in the literature that was reviewed, the tighter accuracy range seems more appropriate.

Hydro provided Knight Piésold with a summary of their assumptions for the development schedule of gas turbine facilities, which indicated that their intention is to build-out SCGT facilities primarily as peaking facilities, with plants to be built first at the existing Brandon (brownfield) site and then at a greenfield site near Winnipeg. The assumed cost of transmission upgrades are $9 million for each new plant at the Brandon facility, $70 million for the first greenfield facility, and $59 million for subsequent greenfield facilities. Pipeline costs were assumed to be $2 million for 1.6 km (16") at the greenfield facility, and $42 million for 27 km (24") to serve the brownfield facility at Brandon. These pipeline costs are in a similar range as to what would be expected for pipelines based on industry construction cost data provided by such publications as RS Means. Knight Piésold have not assessed the transmission line costs for these facilities.

5.4.3 Natural Gas Capital Cost Conclusion

Use of the natural gas capital costs previously assumed for the NFAT at $1.3 million/MW for the CCGT and $0.77 million/MW for the industrial style SCGT is appropriate (excluding transmission line and pipeline costs), with a recommended accuracy range of -15% to +20%.

5.4.4 Operation and Maintenance Costs

For the CCGT facility, Hydro indicated an expected fixed operating cost of $20/kW-year and variable (non-fuel) O&M costs of $3.50/kWh. Hydro indicated to Knight Piésold that they obtained fixed variable O&M costs from the Gryphon report, which in turn developed O&M costs from a literature review. Knight Piésold reviewed recent relevant literature and found reported fixed O&M costs of $6.30/kW-year (Black and Veatch, 2012), $8/kW-year (E3, 2010), $13/kW-year (US EIA, 2013) and $22/kW-year (NETL, 2013) for the CCGT technology and variable O&M costs of $4.90/kWh (E3, 2010), $3.27/kWh (US EIA, 2013) and $3.67/kWh (Black and Veatch, 2012). The assumed O&M costs are within the expected range based on the assessed literature, although there is a significant variation, particularly for the fixed costs.

For the SCGT facility, Hydro indicated expected fixed operating costs $16/kW-year and variable O&M (non-fuel) costs of $4/MWh. For the SCGT turbines costs of $7.30/kW-year (US EIA, 2013), $14/kW-year (E3, 2010) and $5.26/kW-year (Black and Veatch, 2012) are reported in the assessed literature, while reported variable costs usually include fuel costs, but $5/MWh is reported by one source (E3, 2010). The assumed fixed cost is slightly higher than the expected range based on the assessed literature, while the variable O&M costs are lower than reported in the literature reviewed by KP. There is a wide variation in reported costs, and determination of these costs is difficult.

Hydro have assumed a heat rate of 6,652 BTU/kWh for the CCGT, 9,906 BTU/kWh for the industrial SCGT and 9,475 BTU/kWh for the aeroderivative SCGT. This corresponds to reported heat ranges for CCGT facilities of approximately 6,466 – 7,050 BTU/kWh and 9,750-10,850 BTU/kWh for industrial style SCGT power plants (Black and Veatch, 2012; NETL, 2013; US EIA, 2013). These heat rates correspond to efficiency of approximately 51% for the combined cycle facility, and 36% for the simple cycle plant. These efficiencies are within the expected range for the technology, and are considered suitable for inclusion in the NFAT analysis. Further detail should be confirmed during future project assessment stages, particularly when assessing the proposed technology to be utilised in detail.

5.4.5 Natural Gas O&M Cost Conclusion

For the CCGT facility, consideration of a fixed O&M cost of \$20/kW-year and \$3.50/MWh is appropriate, but given the difficulty in determining O&M costs, a sensitivity considering the range \$6.30-\$22/kW-year should be undertaken to assess the potential impact of the wide range of reported fixed O&M costs on the outcome of the development plan.

For the SCGT facility, consideration of O&M costs should model the range of \$5.26-\$16/kW-year for fixed costs and \$4-\$5/MWh for variable costs to assess the potential impact of the wide range of reported fixed and variable O&M costs on the outcome of the development plan.

The heat rates stated by Hydro for the natural gas power plants are considered suitable for inclusion in the current NFAT development plan analysis.

5.5 SOLAR

5.5.1 Capital Costs

Capital Costs for Solar Energy are considered less critical for the current assessment (since it is not included in any of the NFAT development plans), but is a useful resource to consider due to current declines in cost. Although the levelised cost of energy is still higher than other energy sources, the capital cost has reduced by a factor of 10 over the last three decades (IPCC, 2012) and a 22% reduction has occurred in the last 3 years (US EIA, 2013). The NFAT assumes solar PV development would be on the basis of 20 MW facilities. Transmission costs are excluded from the base assumptions provided herein. A comparison of the capital costs are provided in Table 5.1.

Table 5.1 Capital Costs Assumed for the NFAT with Comparison Costs Obtained from Review of Recent Relevant Literature (Black and Veatch, 2012; US DoE, 2012; US EIA, 2013).

PV System Type	NFAT Cost (\$/kW)	Comparison Cost (\$/kW)
Fixed Tilt	3,750	3,400-4,300
Single-Axis Tracking	4,500	3,900-4,700
Dual-Axis Tracking	5,000	5,100-5,500

NOTE:
All costs assume a 77% DC to AC derating factor.

It is apparent that the assumed capital costs for the fixed tilt and single-axis tracking PV systems fall within the expected range based on the assessed literature, and the dual-axis tracking system is slightly lower than expected (but considered reasonable for the purposes of the current assessment).

The recent trend in solar PV costs has seen project costs reduce as more experience develops in the market (IPCC, 2012). Figure 5.3 shows the significant project cost improvements for utility scale projects, which are expected to continue. Figure 5.3 shows projected future cost reductions, with possible sources of cost reductions as the PV market continues to grow worldwide. Consideration of larger PV facilities may also yield economies of scale that would reduce overall project costs per installed capacity.

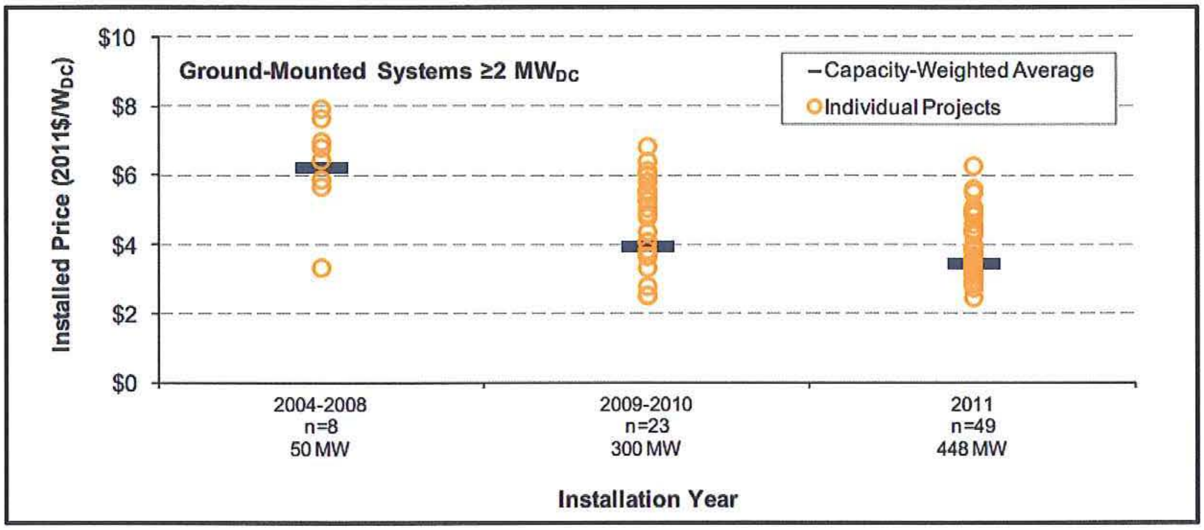


Figure 5.3 Recent Utility-scale Solar PV Cost Trends (US DoE, 2012).

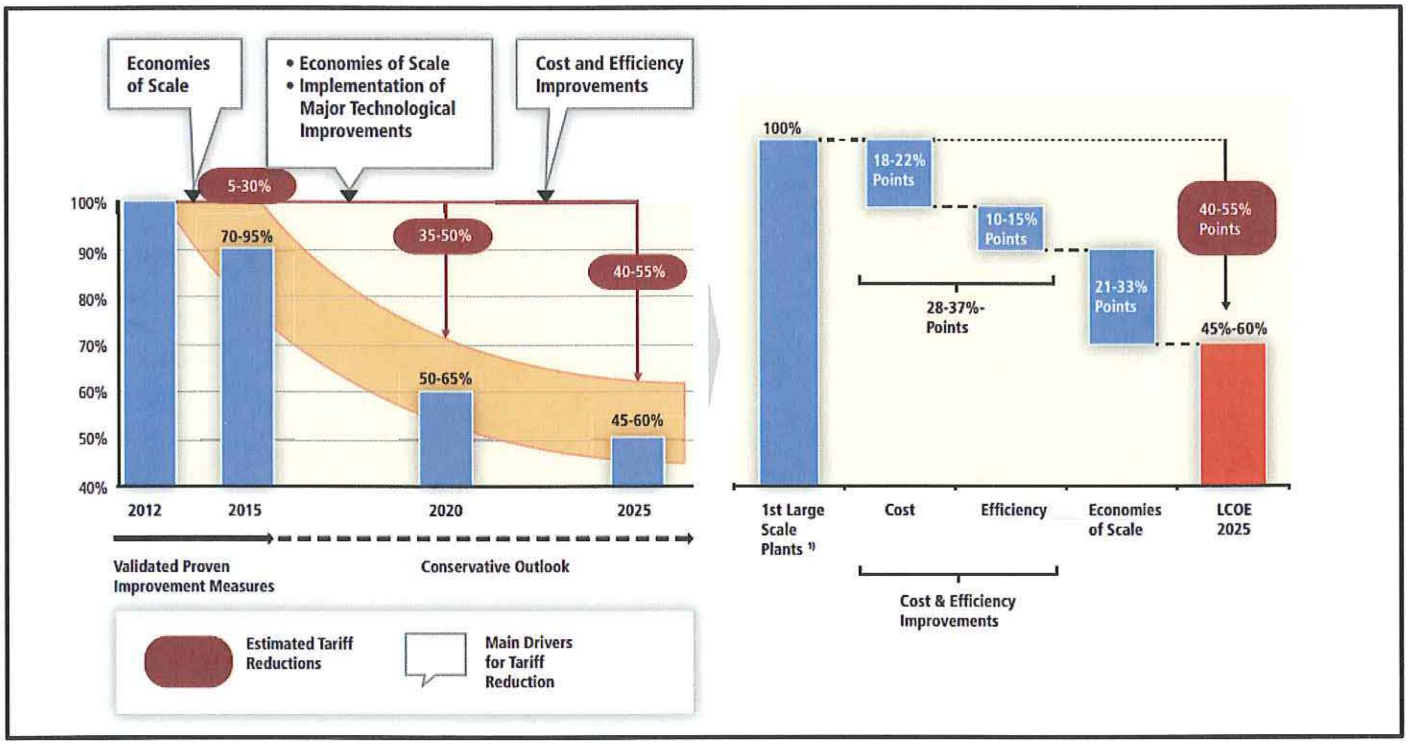


Figure 5.4 Project Future Cost Reductions for Solar PV Systems (IPCC, 2012).

Hydro has considered Solar PV to be a "Stage 1 – Inventory" resource for the purposes of the NFAT assessment. This is considered reasonable for this level of study, but we suggest that the lower end of the AACE cost estimating accuracy range for a Class 5 estimate (-20% to +30%) be utilised in lieu of Hydro's suggested cost accuracy range (-50% to +100%) primarily due to the rapid reductions in PV costs, but also due to the smaller range of reported costs in recent reports (US DoE, 2012). Constant assessment of current PV project prices would be a more prudent modelling strategy than projecting future costs using a wide cost estimate "bounds" as per the AACE cost accuracy range.

5.5.2 Solar Capital Cost Conclusion

The assumed capital costs for solar PV are reasonable, but are subject to rapid change. Hydro should continually review the current costs of PV technology during the implementation of their development plan, as projected future cost reductions may decrease the levelised cost of energy to a point that solar PV could be considered cost competitive for energy generation in Manitoba.

5.5.3 Operation and Maintenance Costs

Operation and Maintenance Costs are summarised in Table 5.2, and indicate that O&M costs are slightly lower than the expected range. As for the assessment of other technologies (wind and natural gas), the literature review reveals a wide range of expected O&M costs reported by different authors.

Table 5.2 O&M costs assumed for the NFAT with comparison costs obtained from review of recent relevant literature. Comparison studies sources: (Black and Veatch, 2012; US DoE, 2012; US EIA, 2013).

PV System Type	NFAT O&M Cost ($/kW-year)	Comparison O&M Cost ($/kW-year)
Fixed Tilt	19.70	22-50
Single-Axis Tracking	21.10	22-50
Dual-Axis Tracking	24.60	25-50

5.5.4 Solar O&M Conclusion

Any planning studies undertaken by Hydro that use solar PV as part of the development plan should include sensitivity analysis on O&M costs for the entire range of costs reported in the literature to determine the impact of varying O&M costs on levelised cost of energy.

6 – CONSTRUCTION MANAGEMENT, SCHEDULE AND CONTRACTING FOR WIND, GAS, AND SOLAR

6.1 SCOPE OF WORK

Question 5: "Review and assess Manitoba Hydro's construction management plans, schedule, and contracting methods for the design, engineering, procurement, construction, start up, commissioning, testing, and commercial operation for wind, natural gas combined cycle gas turbines, and solar facilities."

6.2 WIND

Hydro have assumed for the purposes of the NFAT analysis that wind power projects would be developed "in-house" by Hydro. This contrasts with the installed wind energy projects in Manitoba, which have been developed by Independent Power Producers (IPPs) with a long term power purchase agreement with Hydro. Hydro has indicated a time frame of approximately 3-5 years for the development and construction of a generic wind energy facility with an asset life of approximately 20 years. Based on Knight Piésold's understanding of the development of wind energy projects, an estimate of 3-5 years for development and construction of a 65 MW appears reasonable for planning studies. The report prepared by GL GH indicated a development and construction schedule of approximately 2 years, but this excluded wind resource assessments which would likely require at least one additional year (or more). No further detail was provided by Hydro, and may not be necessary for an early feasibility stage resource. More detailed plans would need to be developed should wind power be shown to be cost effective through either the current NFAT review process or through further reductions in capital costs in future years.

6.3 NATURAL GAS

Hydro have assumed for the purposes of the NFAT analysis that natural gas power projects would be developed by Hydro and constructed through a turnkey EPC contract. This would complement the two existing thermal energy facilities (Brandon and Selkirk) currently operated by Hydro. Alternative development/ownership/operations scenarios could be further assessed in future development of gas fired power options, but the assumption is sufficient for the current level of analysis. Hydro have indicated a time frame of approximately 3-5 years for the development and construction of a CCGT or industrial style SCGT facility and 3 years for the development and construction of an aeroderivative SCGT facility. The natural gas technologies report prepared by Gryphon indicated that a shorter timeframe may be likely, particularly for the SCGT facilities, which has fewer components and a shorter on-site construction period. It would appear that the delivery time of the major pieces of equipment is the key time constraint on the construction of a natural gas facility. We therefore consider a timeframe in the range of 2-4 years to be a suitable minimum for planning purposes (with the CCGT facilities being longer than the SCGT facilities). To allow for contingency due to the early stage of development, the timeframes considered by Hydro for the NFAT are considered reasonable for the purposes of the assessment. No further detail was provided by Hydro, although a preliminary schedule is provided by Gryphon in their natural gas technologies report. A more detailed schedule and development plan should be prepared by Hydro should natural gas facilities be considered a suitable energy option as a result of the current NFAT assessment, or as part of any future development plan.

6.4 SOLAR

Hydro have indicated an approximate development and construction timeframe of 3 years for the generic 20 MW solar facilities. Given the preliminary nature of the solar energy resource option, an assumption of a 3 year minimum development timeframe may be considered reasonable, although this may be able to be reduced if solar were to be developed as a key energy resource in Manitoba in future years. Hydro should prepare a more detailed development plan if solar energy cost reductions lead it being considered a suitable resource for development in Manitoba in later stages of the current development plan.

7 – CAPITAL EXPENDITURE FORECAST

7.1 SCOPE OF WORK

Question 6: "Review Manitoba Hydro's capital expenditure forecasts CEF 13/CEF 12/CEF 11/CEF 10/CEF 9 and explore any significant factors that led to cost increases over successive forecasts."

7.2 CAPITAL EXPENDITURE FORECAST

Hydro's Integrated Financial Forecast (IFF) is a projection of financial statements for the corporation. The Capital Expenditure Forecast (CEF), a portion of the IFF, incorporates the assumptions related to new long-term generation and transmission resources required, as well as expenditures required to sustain the existing infrastructure and to meet safety, regulatory and load growth requirements.

7.2.1 Successive Capital Expenditure Forecasts

The successive cost estimates for Keeyask and Conawapa as they appear in respective CEFs are as shown in Tables 7.1.

Table 7.1 Progression of Project Costs in $ Millions

Click here to enter text.	CEF09	CEF10	CEF11	CEF12	CEF13
Conawapa GS	6,325	7,771	7,771	10,192	10,492
Keeyask GS	4,592	5,637	5,637	6,220	6,220

7.3 MINOR FACTORS

7.3.1 No Updates to the Cost Estimate

In certain years the cost estimate was not updated to reflect the latest actual escalation rates or new considerations. The lack of difference actually reduces the level of contingency considered in certain instances.

7.3.2 Delay of In-Service Date

Variations in projected in-service dates adds project costs related to interest and escalation. The progression of anticipated in-service dates is shown in Table 7.2.

Table 7.2 Projected In-Service Dates

Click here to enter text.	CEF09	CEF10	CEF11	CEF12	CEF13
Conawapa GS	May 2022	May 2023	May 2024	May 2025	May 2026
Keeyask GS	Dec 2018	Nov 2019	Nov 2019	Nov 2019	Nov 2019

The Conawapa in-service date was deferred by one year from 2023/24 in CEF10 to 2024/25 in CEF11 with the total project cost maintained at $7.8 billion, effectively reducing the project contingency. However, when the in-service date was deferred one further year (to 2025/26) in

CEF12, the base estimate was increased and escalation and interest are, as a result, consistent with a 2 year deferral.

7.4 SIGNFICANT FACTORS

Two significant shifts have occurred in the cost estimates: one from CEF 09 to 10, the second from CEF 11 to CEF 12.

7.4.1 2009/2010 Updates from the 2007 Basis of Estimates

The CEF 09 to CEF10 shift is imputed to the updated cost estimates associated with the latest KGS ACRES Basis of Cost Estimate Reports. The tables in each of these reports include detailed differences between the previous Basis of Estimate Dated 2007 and the Updated estimates of 2009 or 2010. The updates included escalation to the new date using a single escalation factor provided by Hydro.

The major changes are identifies as:

- Updates to estimates for Turbine Generators
- Updated assumptions on Margin Calculations (changes in contracting strategy, additional use of subcontractors, GCC supply of cement and reinforcement, and all the associated mark-ups)
- Corrected gate guide unit rates
- Concrete length of shift and operator payment changes
- Corrections to mobilization
- Updates to estimates for reinforcing steel and cement, and
- Correction for office in directs.

Most of these new inclusions were based on the experience gained as Wuskwatim, and the bulk of the physical project description was unchanged.

7.4.2 Inclusion of the Management Reserve

Hydro 2012/13 and 2013/14 Electric General Rate Application Exhibit # 91 explains the cost escalation from CEF11 to CEF12 refiled as part of PUB/MH I-040. The details are copied over to Table 7.3 and Table 7.4 .

The factors described all appear justified namely:

- The inclusion of the management reserves
- Increased actual escalations, and
- Changing interest rates

The only aspect not readily verifiable was the amount allocated to increased adverse effects and regulatory and environmental costs related to sturgeon activities, First Nation activities and preparation of EIS.

Table 7.3 Keeyask Cost Differences from CEF11 to CEF12

Cost Breakdown	Increase (million $)	Explanation
Labour Management Reserve	384	Increase to reflect potential additional costs associated with higher risk in labour productivity
Escalation Management Reserve	116	Increase to reflect potential additional costs associated with higher risk in escalation
GS Actual Escalation	187	Base estimate revised 2009$ to 2012$ for actual escalation that has exceeded projected escalation
Infrastructure	17	Upgrade to camp accommodation for worker attraction and retention
Planning and Licensing	34	Increased adverse effects and regulatory and environmental costs related to sturgeon activities, First Nation activities and preparation of EIS
Transmission Lines	26	Increased detail in scope identifying number and type of towers required as well as addition of lines from G.S. to switching station
Transmission Stations	34	Increased detail in scope identifying breaker replacements and bank addition required
Interest and Other	-215	Decrease in interest rates partially offset by increase in costs
Total Increase	583	
Source: 2012/13 and 2013/14 Electric General Rate Application Exhibit #111, Undertaking # 46. And Refiled as part of PUB/MH I-040.		

Table 7.4 Conawapa Cost Differences from CEF11 to CEF12

Cost Breakdown	Increase (million $)	Explanation
Labour Management Reserve	510	Increase to reflect potential additional costs associated with higher risk in labour productivity
Escalation Management Reserve	337	Increase to reflect potential additional costs associated with higher risk in escalation
Base Estimate Increase	366	Removal of negative contingency due to deferral of in-service
GS Actual Escalation	150	Base estimate revised 2009$ to 2012$ for actual escalation that has exceeded projected escalation
Infrastructure	-59	Section of PR 280 upgrade no longer required due to re-routing through Keeyask G.S.
Contingency	166	Increased adverse effects and regulatory and environmental costs related to sturgeon activities, First Nation activities and preparation of EIS
Escalation	421	Increase mainly due to the 2-year in-service deferral
Interest	530	Increase due to addition of management reserves, higher costs and 2-year in-service deferral partially offset by decrease in interest capitalization rates
Total Increase	2,421	
Source: 2012/13 and 2013/14 Electric General Rate Application Exhibit #111, Undertaking # 46. And Refiled as part of PUB/MH I-040.		

8 – HISTORICAL PERSPECTIVE ON THE CONSTRUCTION COST COMPONENTS OF OTHER GENERATING STATIONS ON THE LOWER NELSON RIVER

8.1 SCOPE OF WORK

Question 7: "Provide a historical perspective on the construction cost components of other Lower Nelson River hydraulic generating stations (Limestone/Long Spruce/Kettle) and analyze the major components of direct cost, including:
(a) Spillways/dams/dikes;
(b) Powerhouses; and
(c) Turbines and generators;
and compare these to the Keeyask and Conawapa GS costs for these components."

8.2 ASSESSMENT

A meaningful assessment of historic Nelson River projects is not possible with the information made available. Hydro provided total project costs but specific component costs were not available. Publically available descriptions of Limestone, Long Spruce and Kettle were therefore referenced to provide a perspective on the construction history of each project. A breakdown of the costs was reflected in a rate case Capital Cost IR(s) 10 – MH Exhibit #68, but was not readily usable as presented without supporting information.

In the absence of specific component details, a Present Value analysis of each project was developed using published Hydro CPI values. However, these only go back to 1987 and therefore are only relevant to Limestone GS (1992). Long Spruce (1979) and Kettle (1973) were completed pre-1987, and may require use of Canadian CPI values. Realistically Present Value calculation is an over simplification and will offer no defendable conclusions when you consider changes in the labour market, environmental considerations and consultation, and other factors.

According to Hydro Undertaking # 47 (MH Exhibit #91) significant differences from the period in which the Limestone, Long Spruce and Kettle Generating Stations were developed and the period in which the Wuskwatim Generating Station was developed (and Keeyask and Conawapa will be developed) are:

- Hydro is engaged in a partnership framework,
- Significant increase in the degree of rigour required environmentally under the Canadian Environmental Assessment Act and The Environment Act (Manitoba) both of which came into existence after Limestone was completed. A related effect was that, because the legislation was new, there was no experience base among the federal and provincial regulators in Manitoba, which added another dimension to project scheduling.
- Labour costs and productivity.

8.3 LIMESTONE GS

Limestone Generating Station completed commissioning in 1992, ahead of schedule and below budget. Generally speaking, Limestone GS is most similar to Keeyask. Hydro attributes meeting the budget to lower interest rates and escalation costs. However construction of Limestone was suspended following completion of the cofferdam in 1978 and then restarted in 1985. It is unclear when and how the final project budget of $1.43 billion was prepared or revised. Based on these numbers, Limestone with a capacity of 1,340 MW equated to a cost of $1.07 million per MW at the time.

Using the same generic metrics as reported in section 2, with no financing cost, time, cost of money, etc. the overnight capital cost of the facility today would be around $2.2 billion (see Table 8.1). Escalating the $1.43 billion 1992 all-inclusive reported cost at a generic 2.5% for 11 years produces an estimated cost of approximately $1.88 billion which is less than what the project could be expected to cost today.

Table 8.1 Limestone GS Overnight Order of Magnitude Cost Estimate

	Quantity[1]	Unit	Unit Cost ($)		Cost ($)
Excavation (assuming 50/50 split of reported total quantity)					
Unclassified	1,600,000	m^3	20		32,000,000
Rock	1,600,000	m^3	100		160,000,000
Coffer Dam removal	3,500,000	m^3	20		70,000,000
Earth Fill	2,900,000	m^3	40		116,000,000
Concrete	650,000	m^3	1,200		780,000,000
Capacity (Generating Plant)	1,350	MW	500,000		675,000,000
					1,833,000,000
+20 % for miscellaneous items					471,380,000
					2,199,600,000

Source: (1) http://www.hydro.mb.ca/corporate/facilities/brochures/limestone_1107.pdf (2) KP Generic Metric.

8.4 LONG SPRUCE GS

Long Spruce Generating Station started with road construction in 1971, followed by cofferdam construction in 1973 and plant commissioning completed in 1979. No references to schedule or budget performance were made available. Long Spruce is a 1,010 MW plant which was constructed for $508 million i.e. for $503,000/MW which is roughly the unit price of the turbine generators units alone in today's terms. As such the cost cannot reflect the cost in today's terms.

8.5 KETTLE GS

Kettle Generating Station was commissioned in 1974 for $240 million. With a plant capacity of 1,220 MW this equates to $197,000 per MW. Escalating $197,000/MW at 2.5% for 35 years would equate to $470,000/MW which is roughly the unit price of the turbine generators units alone in today's terms. As such the cost cannot reflect the cost in today's terms.

9 – JUSTIFICATION FOR INCREASING COSTS

9.1 SCOPE OF WORK

Question 8: "Analyze Manitoba Hydro's justifications for increasing direct costs and for increasing indirect costs with respect to:

a. Labour productivity and shortages;
b. Competition with other large civil projects in Canada;
c. Remote location;
d. Northern and First Nation jobs; and
e. Other contractual hiring constraints."

9.2 LABOUR PRODUCTIVITY AND SHORTAGES

Labor productivity in the construction industry has been documented to have decreased since its peaks in the 70's. The biggest factor has generally been attributed to a reduction in skill level of the average worker. Other important factors include declines in the average number of employees per establishment, the capital-labor ratio, percentage union, and the average age of workers. Canada is experiencing at least a decade of labour shortages across the construction trades, with insulators and steamfitter-pipefitters among those in highest demand, according to reports from the Construction Sector Council.

Hydro imputed the lack of productivity to difficulties hiring staff, staff retention, and the use of inexperienced staff. Hydro has included additional costs to the direct and indirect cost estimation as a result of the lessons learned at Wuskwatim; they have adjusted the contracting methods, added staffing requirements and invested in better camp facilities in an attempt to cope with the low productivity experienced on Wuskwatim. The added costs appear to be prudent and reasonable.

9.3 COMPETITION WITH OTHER LARGE CIVIL PROJECTS IN CANADA

The upcoming demand for skilled construction labour on Hydro's upcoming projects is substantially greater than was experienced during Wuskwatim. At Wuskwatim, approximately 40% of the overall project workforce came from outside of Manitoba and 60% of the workforce for constructing the generating station structure came from out-of-province. As such, Hydro is certain it will have to compete for skilled construction labour as the Manitoba workforce is not expected to be sufficient to meet the demand. It has also been KP recent experience in British Columbia that contractors needed to bring in an eastern Canadian work force to complement the local work force for the construction of the local hydropower projects.

KP is also of the opinion that competing nationally for skilled construction labour will present a major challenge for Hydro. A review of the civil tender documents (due December 2013) will reveal how and what cost the large contractors believe they will be able to mobilize the crew required.

Hydro has related the difficulty strictly to the ability to offer competitive wages and a suitable camp environment.

9.4 REMOTE LOCATION

A large number of large industrial and engineering projects are located in remote northern communities. Since the project location is known, the associated impact on cost in either known or the uncertainty around the cost is identifiable in some form and accounted for in the contingency. The project location should not have a repercussion leading to an increase in the cost estimate; it should already be part of the cost estimate. This has been accounted for in 2009 updates with the changes related to staff rotations.

9.5 NORTHERN AND FIRST NATION JOBS

Remote northern large projects have always been a big part of Canada's non-residential construction outlook, but the proportions are expected to rise. Hydro, rightly, expects the skills shortage to be particularly acute all across northern Canada, where natural resource development and mining projects are projected to grow significantly through 2020.

9.6 OTHER CONTRACTUAL HIRING CONSTRAINTS

The Burntwood Nelson Agreement (BNA) sets out terms of employment for all "hands-on-the-tools" workers and employees (including aboriginal workers) who work on hydro construction projects in Northern Manitoba and contains many detailed provisions. It is the collective agreement between the Hydro Projects Management Association (HPMA), which represents Contractors, and the Allied Hydro Council of Manitoba, which represents Unions.

KP is not able to directly ascertain the impact of this agreement, but as often mentioned in this report, the tenders for the civil contract (which must comply with the BNA) will be telling of this possible significant hiring constraint.

9.7 KEEYASK GENERAL CIVIL CONTRACT TENDERS

In summary, it is KP's opinion that the Keeyask General Civil Contract tenders submitted to Hydro in December 2013 should confirm whether the large contractors believe they will be able to staff the construction project in a cost effective manner

10 – HIGH LEVEL ASSESSMENT

10.1 SCOPE OF WORK

Question 9: "Please provide a high level assessment of the construction planning and management of the construction costs of the new Preferred Development Plan projects, including the experience gained from the Wuskwatim project."

10.2 CONSTRUCTION PLANNING AND MANAGEMENT

This topic has been covered in sections 4.2, 4.3, and 4.4.

10.3 EXPERIENCE GAINED FROM WUSKWATIM

10.3.1 Cost Estimates

The recent updates to the Keeyask & Conawapa total project costs are the result of re-estimates that incorporate experiences from the Wuskwatim project. This includes updates to labour, material and equipment rates as well as updates to the assumed labour productivity.

As displayed in PUB/MH I-036a, the capital costs for Wuskwatim Project inclusive of transmission increased from $988 million in CEF03 to $1,771 million in CEF12 (a 79% increase). Undertaking # 47, refiled as PUB/MH I-038, provides an explanation of the escalation in construction costs for Wuskwatim from the initial estimate to the final actual costs (as shown in Table 10.1). In summary the construction phase of Wuskwatim witnessed lower than expected productivity rates and occurred during a period of international commodity escalation (direct cost escalation) and 3 year delay of the in-service date to June 2012 (indirect cost).

Table 10.1: Integration of Lessons Learned at Wuskwatim

Cost Breakdown	Increase in Wuskwatim Cost Estimate between 2003 and 2012 (M$)	Explanation for change by Manitoba Hydro In Undertaking # 47	KP Designated Implication for Keeyask and Conawapa
Pre-construction 2003 to 2006	224	Extended duration of federal and provincial approvals as well as PDA and NCN ratification resulting in the deferral of the construction start date, extended duration of construction, and the 3-year in-service date deferral.	Addressed through the separation of the KIP. Project definition for pre-construction work could still be refined.

General civil contract	178	Lower trade labour productivity, higher labour rates, increased bedrock overbreak, and increased engineering	Awareness of the issue, inclusion of different staffing requirements included. Similar Risks still exist, but are addressed in part (through Labour Management Reserve)
Turbines & generators	19	Higher labor rates, extra work, claims due to schedule delays.	Considered
Site preparation	32	Increased quantities (primarily rock) due to unknown site conditions, increased camp accommodations and operation and maintenance costs.	Remain
Catering	22	Higher camp occupancy and higher offsets required for work performed through a direct negotiated contract.	Addressed through projected increased staff requirements in the 2009 and 2010 estimates.
Electrical & Mechanical	38	Additions to scope of work and engineering, and contractor cost claims due to schedule and access delays.	Risk remains due to Hydro contracting technique.
Gates, Guides & Hoists	20	Extra work and contractor cost claims due to schedule delays.	Gate guides addressed in 2009 Estimate, marginal impact.
Staff house	30	Addition of staff house to meet staffing requirements	Addressed through projected increased staff requirements in the 2009 and 2010 estimates.
Transmission	109	Increases in market costs experienced for labour, materials and contracts partially offset by reductions in contingency, project management and contract costs nearing construction completion.	Not investigated but should be part of escalation.
Other	47	Actual escalation in excess of original estimated inflation and other cost increases	Predictable, low CPI still included in escalation rate, addressed partially with escalation reserve
Interest allocated to construction capital	64	Due to increases in costs and deferral of in-service date partially offset by lower interest rates	Justified
Total increase	783		

10.3.2 Access and First Nation Engagement

Advancing infrastructure work ahead of the generating station provides benefits to First Nations, such as increased and advanced employment, training and capacity-building opportunities, as well as reducing financial risks to the First Nation joint venture partners. This was pursued on Keeyask to avoid a repetition of the difficulties experienced with a First Nation joint venture partner at Wuskwatim. In addition there are benefits to the generation project by advancing the in-service date and reducing construction delay risks. Interestingly enough Knight Piésold has witnessed this approach undertaken successfully on a number of mining projects and Independent Power Producer hydro projects in British Columbia whereby local First Nations partners can be engaged up front in clearing and access road development, while the project developer takes needed time to engage the heavy civil contractor.

10.3.3 Changes to Construction Planning and Management as a Result of Wuskwatim Experience

Wuskwatim was originally bid as a Design Bid Build (or Unit Price) Contract in 2007 but only one bid was received which was too high to pursue. Four subsequent bids on a cost reimbursable type contract were received which included better prices. This experience drove the selection of the Keeyask and Conawapa contracting method.

The Wuskwatim Project was the first project in which Hydro engaged in a partnership framework, which required additional time to arrange and increased preferential costs.

Changes to construction planning and management as a result of the Wuskwatim experience are discussed in section 7 related to updates in the 2009 estimate that incorporate greater allowances for camp space requirements, staff turnover, and the inclusion of specifics to address concrete productivity. The inclusion of the management reserve is also the result of the Wuskwatim experience.

Evidence that process review results have been applied to the Keeyask and Conawapa Projects' planning, construction and cost estimating processes to realize improved project controls are:

- Contract framework - "target price" contracts are utilized to improve alignment with the prevailing market and to share cost escalation risk
- Market research into craft labour and heavy construction costs and productivity - findings include strategies for recruitment and retention by specific contract strategies for each work package, and
- Earlier scheduling for development arrangements, agreements and adverse effects - and careful management through integration of engineering, regulatory and procurement processes.

It was recognized that several of the underlying drivers for the increase in the estimate for the Wuskwatim project during construction may continue throughout much of the period during which Keeyask and Conawapa will be constructed, and that the rate of construction cost escalation will likely exceed the rate of increase in the CPI, this lessons learned appears only partially addressed.

Additionally, labour reserve funds have been included in the current estimates for Keeyask and Conawapa to address major risk items not addressed through the normal scope of contingency.

10.4 COST ESTIMATE APPRECIATION

A high-quality cost estimate satisfies four characteristics: it is credible, well-documented, accurate, and comprehensive.

10.4.1 Credibility

The direct point cost estimate is credible and has been prepared by a reputable engineering firm with a wealth of recognised hydropower expertise (KGS-ACRES Ltd.). The assumptions and estimates are realistic. They have been cross-checked by Hydro though they have not been reviewed through an independent cost estimate. In this regard the GCC Civil Tenders will add a degree of independence to the estimate. The level of confidence associated with the Point Estimate has been identified and a sensitivity analysis has been conducted (i.e. an examination of the effect of changing one variable relative to the cost estimate while all other variables are held constant in order to identify which variables most affect the cost estimate).

There is probably little that can sensibly be done to improve the present estimate until tenders are received for the works. The most significant of these is for the General Civil Works. Tenders for this contract have been received and MH is presently reviewing these, with the intent of selecting one contractor with whom they will work to finalise the scope of work and cost thereof. Even though the outcome of this process will presumably be some change in the overall cost estimate it should be possible to obtain greater confidence already, based on the tenders received.

10.4.2 Documentation

KP believes that the direct point estimate costs are well-documented and the supporting documentation includes a narrative explaining their development. The proposed layout and design of the generating stations appears to be well defined and consistent with good utility practices.

KP would have liked to see more of the documented information surrounding the indirect costs not related to infrastructure, and information related to the cost parametric and expected value contingency modelling method adopted by Hydro. The details behind the management labour reserve were also not made available.

The internal use of the sharepoint site and the obvious care to document internal standards reinforces the fact that the projects are well documented overall.

10.4.3 Accuracy

KP believe that the estimate is likely as accurate as can reasonably be achieved based on the assumptions given despite not fitting exactly with the AACE buckets relating level of project definition to accuracy.

10.4.4 Comprehensiveness

KP believes the estimate to be comprehensive. It accounts for perceivable possible costs associated with the project and is structured in sufficient detail to insure that costs are not omitted or duplicated. It has been formulated by an estimating team with a composition commensurate with the assignment.

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12 – CERTIFICATION

This report was prepared, reviewed and approved by the undersigned.

PROFESSIONAL PROVINCE OF BRITISH COLUMBIA B. S. FICHOT # 30575 ENGINEER

Prepared: Jan 24 2014

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24 Jan 2014.

Approved:

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APPENDIX A

TERMS OF REFERENCE FOR NFAT REVIEW

(Pages A-1 to A-26)

THE MANITOBA PUB UTILITIES BOARD
NEEDS FOR AND ALTERNATIVES TO REVIEW OF MANITOBA HYDRO'S PROPOSED PREFERRED DEVELOPMENT PLAN

REQUEST FOR QUALIFICATIONS
OF INDEPENDENT EXPERT CONSULTANTS

June 2013

CONTENTS

INTRODUCTION

The Manitoba Public Utilities Board (PUB) regulates a number of Manitoba public utilities:

- It regulates the rates charged by Manitoba Hydro (electrical utility), Manitoba Public Insurance (auto insurance), some gas or propane utilities (Centra Gas, Stittco, Swan Valley Gas Corp.) and all water and sewer utilities outside Winnipeg.
- It licenses owners and agents under The Cemeteries Act and funeral directors under The Prearranged Funeral Services Act.
- It supervises the construction and operation of natural gas and propane pipelines, and make sure that gas and propane are safely distributed to Manitoba consumers.
- It registers brokers of natural gas under the Public Utilities Board Act.

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 PUB to conduct the NFAT for the Keeyask and Conawapa Generating Stations and their associated transmission facilities. The Terms of Reference have been included in Appendix A.

PUB members assigned by the Chair to conduct the NFAT will constitute the NFAT Panel (Panel).

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 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. The estimated capital cost of Hydro's preferred development plan is in the order of $20 billion.

About 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, interveners, presenters 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.
2. An assessment as to whether the Plan is justified as superior to potential alternatives that could fulfill the need.

Scope of the Work

The Panel may engage the services of 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 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 as 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, to be held in Winnipeg between February 24, 2014 and May 2, 2014 and shall be available as a resource to legal counsel for registered interveners as deemed necessary by the PUB to prepare for the cross-examination of Hydro witnesses on Commercially Sensitive Information. As the Hearing draws nearer a schedule of events will be shared with all parties. A preliminary schedule of events has been included in Appendix B – Proposed Schedule of Events.

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 othenruise 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.

Scope of Independent Expert Consulting Services

Based on the terms of Reference for the NFAT review, the scope of the Panel's review and the scope of independent expert consultant services are very broad. The independent consultant(s) must have a high level of expertise in a number of specific disciplines. The selected consultants will be required to:

- Review the submissions of Manitoba Hydro (including confidential information), which will be filed no later than August 16, 2013.
- Critically examine the evidence provided by Hydro and other intervening parties.
- Work with intervening parties in the review of Hydro's evidence as deemed appropriate by the Panel.
- Assist the Panel in preparation of information requests to Manitoba Hydro and other registered interveners that may provide evidence.

- Serve as a technical resource to the Panel to provide advice and reports on issues that may transpire during the course of the review.
- Prepare reports on relevant matters to be filed as evidence on the public record.
- Provide testimony and be available for cross-examination on the issues.
- Work collaboratively with other consultants retained by the Panel as well Panel advisors and Public Utilities Board professional staff.

A more detailed Scope of Work and Deliverables will be identified once the expert independent consultants have been finalized. The independent consultant(s) will report to the Panel tasked with conducting the NFAT review. Reporting by the expert consultant(s) will be to the designated Panel project manager for the NFAT.

REQUIRED EXPERTISE

The Board recognizes that one consultant may not have the expertise to cover all the various issues and disciplines required to assist the Board in this review; therefore, the Board may enlist the services of two or more consultants to provide the expertise needed. Selected consultants are expected to cooperate with other selected consultants, PUB Advisors, PUB staff and Interveners as directed by the Panel. Once the consultants have been selected a more detailed assignment of expert areas and work requirements will be identified.

Independent Consultant Services are required for the following service categories. In your RFQ submission, you will be asked to complete a checklist demonstrating which service categories you are providing expertise in:

- Load forecasting
- Midwest Independent System Operator (MISO) Marketplace
- Demand Side Management and Energy Efficiency
- Power Resource Planning and Economic Evaluation
- Construction Management and Capital Costs
- Transmission Line Construction and Costing
- Environmental Issues
- Socio-Economic Analysis
- Business Development and Risk Assessment

LOAD FORECASTING

The examination of Manitoba Hydro's domestic load forecast will be an important component in the determination of future domestic loads, available energy and capacity for export, and the timeline for generation resources to meet domestic load demands and export commitments.

Load forecasting experience requirements include:

- Econometric and end-use forecasting
- Short and long-term domestic load forecast modeling
- Scenario planning for examination of variations to projected load forecasts from loss or gain of an industry, economic changes, technology changes and energy efficiency measures
- Probability analysis of projected load forecasts
- Retrospective load analysis
- Comparison of load forecast with similar markets
- Examination of peak demand and energy trends including seasonal variations in load forecasting
- Transmission and distribution losses under various loads and weather occurrences and the assignment of such losses to various customer classes
- Impacts on load forecasts resulting from potential fuel switching
- Incorporation of demand side management and energy efficiency measures
- Timelines for future generation assets to meet domestic load requirements and export commitments.

MIDWEST INDEPENDENT SYSTEM OPERATOR (MISO) MARKETPLACE

Manitoba Hydro currently exports significant surplus energy to the export marketplace. The fundamental premise behind the advancement of Manitoba Hydro's preferred development plan is to take advantage of opportunities in the export marketplace. The bulk of Hydro's exports go to the United States and largely to the MISO market. The consultant's knowledge of the energy market in the US, and in particular the MISO marketplace will be important in the assessment of the business case for the preferred development plan. Experience in energy price projections and future changes in the generation fleet in the MISO marketplace, will play an important role in the review of the overall business case of the preferred development plan.

MISO marketplace experience requirements include:

- MISO energy and capacity markets

- MISO energy and capacity resource mix, projected energy and capacity demands and generation options to meet such demands
- Projected energy and capacity generation stack for energy supply in MISO
- Role of imports into the MISO market and value of "clean" and "renewable" energy
- MISO market utility suppliers and their respective power resource plans
- MISO transmission tariffs
- MISO transmission constraints and transmission availability including transmission rights and the overall transmission marketplace
- Transmission costs and transmission cost allocation
- Impact of Upper Midwest state regulatory energy policy on Hydro's potential export markets
- Renewable energy market, renewable energy mandates, renewable energy credit trading
- MISO ancillary service market and financial impact on Hydro exports
- Generation costs for the MISO Power Resources, US EPA regulations and potential impacts to the MISO electricity market and changes to generation mix
- Analysis of MISO energy market prices in light of projected natural gas prices, generation options, transmission constraints, federal or state renewable energy mandates, ancillary services markets, renewable energy integration
- Allocation of renewable energy costs in rate base and impacts to wholesale energy pricing

Demand Side Management and Energy Efficiency

Demand Side Management (DSM) and Energy Efficiency (EE) programs have the potential to reduce domestic energy and capacity loads. Manitoba Hydro has developed a number of successful energy efficiency programs under the banner of "Power Smart" and has received a number of awards for their energy efficiency programming. Manitoba Hydro will have a new "Power Smart" plan available for consideration by the NFAT Panel for the purpose of this review. Manitoba Hydro's Power Smart program may impact resource development options in Manitoba as well as domestic revenues from energy sales.

Demand side management and energy efficiency expertise requirements include:

- Examination of technical, economic, and real DSM and EE opportunities
- Designing and implementing large utility scale DSM and EE programs at the residential, commercial and industrial levels.
- Knowledge of other North American DSM/EE programs implemented

- The use of Total Resource Cost (TRC) and Rate Impact Measure (RIM) evaluation tools as well as total societal costs and benefit analysis from DSM and EE opportunities
- Measuring actual DSM and EE savings
- Smart grid technologies for DSM
- Determining marginal costs for measuring DSM and EE programs.
- Managing DSM/EE lost opportunity revenues

Power Resource Planning and Economic Evaluation

The examination of Manitoba Hydro's preferred development plan, including alternative development plans, will play a key role in the Panel's mandate in the NFAT review of the resource plan options for Manitoba. The examination of power resource plans will involve a critical review of Manitoba Hydro's export sales contracts, projected opportunity sales, the examination of export contracts and opportunity sales, projected revenues, generation options and costs to meet domestic and export sales opportunities and the development of a business case for the various resource options.

Power Resource Planning and economic experience requirements include:

- Hydro power resource evaluation
- Production cost modeling and other relevant models used by Hydro such as "Splash", "Prism", or other models used in resource planning
- Reservoir operations for optimal value
- Developing power resource plans and alternatives
- Incorporating exports (bilateral contracts and opportunity market pricing) into power resource planning
- Practical role of merchant trading and energy imports
- Risk identification and evaluation
- Generation and integration costs of hydro, wind, natural gas "CCT" and DSM
- Climate change impacts
- Sensitivity analysis
- In-service cost analysis and rate impact evaluation
- Net present value analyses of hydro power and natural gas generation
- Internal rate of return analysis

Construction Management and Capital Costs

Manitoba Hydro is anticipating spending upwards of $20 billion in capital investments in their preferred development plan. Construction cost estimates and cost management must therefore be as thorough and accurate as possible.

Construction management expertise requirements include:

- Large hydro and transmission line capital cost estimating
- Capital and operating costs for other generation alternatives such as wind, combined cycle gas turbines, and solar
- Construction indirect costs including access roads, campsites, off-site mitigation costs
- Cost estimating risks and risk management practices
- Construction tendering practices
- Sensitivity analysis in construction cost estimates
- Construction cost indices

Transmission Line Construction and Management

Manitoba Hydro's preferred development plan includes new AC lines from the proposed northern generating stations to transfer energy south to loads in southern Manitoba. The preferred plan also includes a new Canada-U.S.A. transmission interconnection. In addition, Manitoba Hydro is constructing a new HVDC Bipole transmission line (known as Bipole III) for reliability purposes and to facilitate the transfer of additional power generated from the Keeyask and Conawapa generating stations south to DC converter stations outside of Winnipeg. Bipole III is not part of the preferred development plan and not subject to this review. The new northern AC lines proposed in the preferred development plan will provide additional capacity to complement existing and proposed HVDC transmission lines. These new transmission assets are needed to carry the additional generation capacity from northern generating stations to loads in Winnipeg as well as markets in the US. Transmission capacity requirements, costs, transmission cost allocation (between export and domestic customers) and possible "seams" issues between Manitoba and US jurisdictions will need to be understood.

Transmission line construction and management expertise required:

- Knowledge of AC and DC transmission technologies, loss characteristics, and possible HVDC/AC integration issues
- North American Electrical Reliability Corporation and requirements
- AC transmission costs for lines and substations

- Transmission regulation and approval requirements including approvals from state, provincial and federal agencies
- FERC, DOE and MISO requirements for international transmission line connections and seams issues
- MISO Transmission line cost allocation processes including incremental load methodologies
- Transmission ownership and rights

Environmental Issues

Manitoba Hydro proposes to sell "green" non-emitting clean renewable hydropower under its preferred development plan. The potential benefits of such power would be the move towards a "freedom from fossil fuels" economy in Manitoba as well as to offset potential fossil fuel emissions from production of electricity in the US or other Canadian markets. The environmental attributes from clean renewable hydropower will therefore need to be carefully examined in terms of their value to Manitoba Hydro, the citizens of Manitoba and the potential benefit to Manitoba Hydro customers for the preferred development plan as well as other alternatives.

Environmental expertise requirements include:

- Knowledge of federal, provincial and state regulations and policies for greenhouse gas emissions, renewable portfolio standards and emission requirements for existing and future generation technologies
- Carbon marketplace trading models and current carbon trading practices
- Measuring and calculating the economic value of carbon reducing technologies, including generation alternatives, fuel switching, clean energy exporting, energy efficiency measures and carbon off-set technologies
- Generation emissions for various technologies
- System reservoir operations and incremental reservoir carbon emissions
- Renewable energy credits and credit tracking

Socio-Economic Analysis

The expenditure of approximately $20 billion dollars on new hydro generation and transmission assets will have a significant economic impact to the Province of Manitoba, northern Manitoba communities, impacted First Nations as well as other jurisdictions in Canada and the US. The NFAT review requires the Panel examine what these specific socio-economic impacts are to northern and aboriginal communities as well as the benefits to Manitoba as a whole.

Socio-economic assessment experience requirements include:

- Economic impact assessment modelling to determine sector economic impacts, impacts to provincial GDP, long-term and short-term indirect and induced employment opportunities
- Determining gross provincial financial benefits by examining benefits and costs over the life of the projects
- Determining Canadian benefits
- Northern and aboriginal community-based impacts in terms of employment opportunities, incomes, community tax base, skills development and community business opportunities
- Community access improvements and related health, education and cultural benefits

Business Case Development and Risk Assessment

The expenditure of approximately $20 billion is a significant investment by Manitoba Hydro and the Province of Manitoba. The preferred development plan must demonstrate a clear business case and value proposition, not just to Manitoba Hydro, but also for the people of Manitoba. Such an investment must be critically examined to support advancement of the preferred development plan in light of possible alternatives. All project risks must be identified, quantified and managed to ensure such an investment will prove positive for the people of Manitoba. Given the preferred development involves construction of large hydro generation assets and transmission facilities over a number of years, possible risks include: future wholesale energy price changes, interest rate fluctuations, domestic load fluctuations, droughts, competing technologies, fuel prices, carbon pricing, government regulatory and policy changes, overall economic conditions, construction cost escalation etc. The successful consultant will be required to examine the business case for the preferred development plan and potential alternatives, including the examination and management of risks. The examination of the business case is expected to include inputs from other specialized disciplines such as load forecasting, construction management, export price variability in the MISO market, transmission line construction and management, power resource planning, environmental externalities and socio-economic considerations.

Business case analysis and risk management experience requirements include:

- Crown-owned utility operations
- Examination of business case for large complex energy construction and development projects, specifically large hydro projects
- Expertise in risk identification, quantification, mitigation and management

- Development of Power Resource Plans and Resource scenario modelling
- Flood and drought risks and optimal strategy
- Market value of clean energy from hydro power during various seasonal and peak or off-peak periods
- Future US versus Canadian export opportunities

REQUEST FOR QUALIFICATIONS (RFQ)

The qualification submission should describe your organization's qualifications and experience as it relates to any or each of the requirements describe in the previous pages. Please complete the checklist provided in Appendix C and include it at the beginning of your qualification(s) submission.

The Panel recognizes that not all consultants may have expertise in all the various disciples. The consultant should clearly indicate in their submission which of the specific disciplines they intend to provide services for. Any use of sub-consultants should be highlighted and the sub-consultant should also provide their qualifications as defined in the submission requirements.

SUBMISSION REQUIREMENTS

The Panel is requesting that the consultant qualification submissions be limited to the company's service offering for the required disciplines. The submission requirements include:

- A general description of the consulting services provided
- History of the consultant, ownership structure, number of employees, relevant client service market (industry, government, regulatory agencies, non-government agencies) and a description of where the consultant has provided such relevant services.
- Specific expertise in the disciplines defined above including representative projects and client contact references.
- Designation of the proposed project manager, senior advisors and project coordinators (if applicable) that would be used for the assignment
- Organizational chart of the proposed team
- Brief biographies of proposed professional staff highlighting their specific expertise in the various disciplines and any prior work with Hydro
- Resumes of proposed professional staff (included in an appendix)
- Consultant availability (refer to the proposed Schedule of Events in Appendix B).
- Charge-out rates for proposed professionals

TIMELINES

The PUB is available to respond to any questions you may have about the RFQ. The PUB would like to extend the opportunity to discuss the RFQ by conference call on June 20 and 21, 2013. Please contact the NFAT Project Manager to schedule a conference call.

The following timelines are provided:

- RFQ submission deadline (electronic submissions) — June 28, 2014
- Short List Interviews — July 2 – 10, 2013
- Contract Awards — July 12, 2013

CONSULTANT CONTRACT AWARD

The selection of consultants shall be in the absolute discretion of the Public Utilities Board. Participation by any consultant in this Request for Qualifications shall not give rise to an obligation by the Public Utilities Board to select any particular consultant or any consultant at all, nor to limit its selection of consultants to the parties who responded to this Request for Qualifications. The Public Utilities Board shall have the right issue further requests for qualifications if it deems it to be advisable to do so, and also retain an unlimited right invite individual consultants of the Public Utilities Board's choosing to submit qualifications.

The Panel will review all consultant submissions in response to this Request for Qualifications. The Panel will then meet with selected consultants if required. The consultant (or consultants) deemed successful will be asked to enter into a contractual arrangement to provide the necessary services to the Panel.

Contact Information

All inquiries should be made to

Josée Lemoine
NFAT Project Manager
Telephone: (204) 945-1009
Cellular: (204) 770-3811
Email : josee.lemoine@gov.mb.ca

Consultant Submissions should be made to:

The Manitoba Public Utilities Board
Room 400- 330 Portage Avenue
Winnipeg, Manitoba
R3C-0C4
Attention: Mr. Hollis Singh – Executive Director
publicutilities@gov.mb.ca.

APPENDIX A – TERMS OF REFERENCE

Appendix B – Proposed Schedule of Events

The following is a selection of the proposed scheduled events and may be subject to change.

RFQ Responses	June 28, 2013
Consultant Interviews	July 2 – 10, 2013
Independent Expert Selection	July 12, 2013
Technical Conferences	July 15 and 17, 2013
NFAT Filing by Manitoba Hydro	August 16, 2013
Pre Hearing Conference	September 4,2013
Round 1 IRs	September 6, 2013
Answers to Round 1 IRs	October 15, 2013
Round 2 IRs	November 19, 2013
IE Evidence Due	December 10, 2013
IRs on Evidence	December 17, 2013
Responses to IRs	January 10, 2014
Intervenor Evidence on IRs on Intervenor Evidence	January 27, 2014
Responses IRs	February 3, 2014
Manitoba Hydro Rebuttal	February 20, 2014
Hearing	February 24 – May 2, 2014

Appendix C – Qualification Submission Checklist

Complete the following checklist and include it at the front of your Request for Qualifications' submission.

Qualification	Submission YES or NO	Expert Consultant Name(s)
Load Forecasting		
Midwest Independent System Operator (MISO) Marketplace		
Demand Side Management and Energy Efficiency		
Power Resource Planning and Economic Evaluation		
Construction Management and Capital Costs		
Environmental Issues		
Socio-Economic Analysis		
Business Case Development and Risk Assessment		

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 Reduction 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 MH 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 COMMERCIALLY 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) review 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.

Knight Piésold
CONSULTING

APPENDIX B

SCOPE OF WORK FOR IEC NFAT REVIEW

(Pages B-1 to B-18)

SCOPE OF WORK FOR INDEPENDENT EXPERT CONSULTANTS
NFAT REVIEW
LAST UPDATED: AUGUST 28, 2013

ELENCHUS

Load Forecasting

1. From an energy demand perspective, comment on the extent to which Manitoba's Preferred Development Plan addresses the reliability and security requirements of Manitoba's electricity supply.

2. Review Manitoba Hydro's Load Forecast factors and comment on whether they are complete, reasonable and accurate.

3. Comment on the use of an econometric and end-use forecasting methodology.

4. Assess the reliability of Manitoba Hydro's short- and long-term domestic Load Forecast modelling.

5. Review the extent to which Manitoba Hydro has used appropriate scenario planning to examine the potential impact of changes in the industry, the Manitoba and Canadian economies, available technology (generation and loads) and energy efficiency measures (costs and cost effectiveness).

6. Comment on the appropriate use of probability analysis in projected Load Forecasts.

7. Comment on the extent to which retrospective load analysis provides confidence in the Load Forecast.

8. Review Manitoba Hydro's 2012 in 2013 load forecasts.

9. Compare Manitoba Hydro's 2012 and 2013 Load Forecasts with Manitoba Hydro's historical load forecasts back to 2008 with specific reference to:

   (a) Population growth (birthrates/immigration);

   (b) Changes in the number, size, and occupancy of residential dwellings;

   (c) A comparison of the Load Forecast with similar markets (i.e., are Manitoba Hydro's assumptions consistent with neighbouring jurisdictions); and

   (d) Peak demand and energy trends including seasonal variations in load forecasting.

10. Review Manitoba Hydro's weather adjustment methodology, with specific reference to:

   (a) Non-heating load;

   (b) Electric heating loads;

   (c) Commercial or mass-market consumption;

   (d) Distribution losses; and

   (e) Transmission losses.

11. Assess the consistency of transmission and distribution losses under various loads and weather occurrences and the assignment of such losses to customer classes.

12. Assess the impacts on Load Forecasts resulting from potential fuel switching, particularly in light of recent trends in the cost of natural gas.

13. Comment on price elasticity and the impact of electricity rate changes on demand.

14. Review and comment on Manitoba Hydro's historical and forecast growth in electric heating relative to natural gas heating in the context of electricity and natural gas pricing.

15. Review and comment on the extent to which Demand-Side Management and energy efficiency measures have been relied on as an alternative to generation.

16. Review and comment on the appropriateness of and uncertainty related to the timelines for future generation assets to meet domestic load requirements and export commitments.

17. Comment on the impact of global warming on the Load Forecast

18. Comment on the Load Forecast for industrial and commercial consumers.

19. Upon prior approval by the NFAT Panel, address any other issues that may be identified in reviewing Manitoba Hydro's evidence or are requested by the NFAT Panel.

DSM and Energy Efficiency

1. Review Manitoba Hydro's Demand-Side Management factors and comment on whether they are complete, reasonable and accurate.

2. Review Manitoba Hydro's assessment of technical, economic, and real Demand-Side Management and energy efficiency opportunities relative to other jurisdictions.

3. Review the extent to which Manitoba Hydro has designed and implemented large utility scale Demand-Side Management and energy efficiency programs at the residential, commercial and industrial levels in a manner consistent with other North American jurisdictions where such programs have been implemented;

4. Comment on the proper use of Total Resource Cost (TRC) and Rate Impact Measure (RIM) evaluation tools as well as a Total Societal Costs and benefit analysis from Demand-Side Management and energy efficiency opportunities.

5. Comment on Manitoba Hydro's approach to measuring actual Demand-Side Management and energy efficiency savings.

6. Comment on the appropriateness of Manitoba Hydro's adoption of smart grid technologies for Demand-Side Management.

7. Comment on Manitoba Hydro's approach to determining marginal costs for measuring Demand-Side Management and energy efficiency programs.

8. Comment on Manitoba Hydro's approach to managing Demand-Side Management and energy efficiency lost opportunity revenues.

9. Comment on the reasonableness, thoroughness and soundness of Manitoba Hydro's Demand-Side Management and conservation forecasts.

10. Comment on whether the preferred and alternative resource and conservation evaluations are complete, accurate, thorough, reasonable and sound.

11. Critically assess Manitoba Hydro's DSM Potential Study.

12. Perform independent stress testing of Demand-Side Management levels and an assessment of the reasonableness of Manitoba Hydro's stress testing of 1.5 and 4 times Demand-Side Management spending.

13. Examine Manitoba Hydro's current and potential use of Demand-Side Management in terms of:

    (a) System capacity dispatchability;

    (b) Dependable energy dispatchability;

    (c) Backup resources required;

    (d) Cost effectiveness;

    (e) CO_2 footprint;

    (f) The Role of the Curtailable Rate Program (Peak);

    (g) The Role of the Surplus Energy Program (Energy); and

    (h) The location of Demand-Side Management investments.

14. Identify the potential of Demand-Side Management or energy efficiency to defer new generation in Manitoba, including Keeyask G.S. and or Conawapa G.S. alone or in conjunction with other non-hydraulic resources.

15. Review and comment on the evidence with respect to Demand-Side Management arising from the last Manitoba Hydro General Rate Application, including the role of Demand-Side Management in deferral of Generation Investments put forth by the Consumer Association of Canada (Manitoba) Inc.'s expert witness.

16. Consult with other specialists as directed by the Board regarding the use of Demand-Side Management as a resource option.

17. Upon prior approval by the NFAT Panel, address any other issues that may be identified in reviewing Manitoba Hydro's evidence or are requested by the NFAT Panel.

POTOMAC ECONOMICS

MISO

1. Review the factors considered to arrive at Manitoba Hydro's export market expectations and comment on whether they are complete, reasonable and accurate.

2. Evaluate Manitoba Hydro's opportunity to export energy and capacity into the MISO market in the short term and long term.

3. Evaluate the factors that determine the transmission congestion patterns in MISO that can substantially increase or decrease energy prices for exports over the Manitoba Hydro interface and how MISO's proposed transmission expansion plans may influence energy pricing.

4. Review the energy revenues projected by Manitoba Hydro, benchmarked against your own forecast MISO energy prices in the short term and long term and address:

   (a) The range of retirement assumptions related to environmental regulations affecting coal-fired resources in MISO;

   (b) Alternative future market designs that could substantially affect the prevailing capacity and energy prices in MISO;

   (c) Revenues available via renewable energy credits or other opportunities related to "clean" energy; and

   (d) Other potentially relevant factors affecting Hydro's future export revenues, including:

      (i) Federal and State regulatory actions that could affect export opportunities;

      (ii) Environmental regulations affecting the resource mix in MISO;

      (iii) Transmission congestion and the future allocation of transmission investment costs; and

      (iv) Renewable energy mandates.

5. Review the capacity revenues projected by Manitoba Hydro, benchmarked against your own forecast of MISO capacity prices in the short term and long-term.

6. Review Manitoba Hydro Integrated Financial Forecasts (IFF) dating back to IFF09 and assess the reasonableness of Manitoba Hydro's derived average export prices projected at the time.

7. Compare Manitoba Hydro's historical export price assumptions to the National Energy Board (NEB) data filed by Manitoba.

8. Review the existing and projected MISO market energy supply mix and compare it to Manitoba Hydro's projections. Include a review of the impact of Entergy's and PJM's integration on the capacity and energy pricing in the MISO market.

9. Comparison of other adjacent RTO jurisdiction pricing with MISO.

10. Review Manitoba Hydro's unit export revenues against the natural gas price history and forecast; similarly review these relative to coal and wind.

11. Review Manitoba Hydro's export revenue forecasting process (include ICF's forecasts).

12. Provide a comparable natural gas price and MISO electricity market price history and forecast over 20/40/80 years.

13. Upon prior approval by the NFAT Panel, address any other issues that may be identified in reviewing Manitoba Hydro's evidence or are requested by the NFAT Panel.

KNIGHT PIÉSOLD CONSULTING

Construction Management and Capital Costs

1. Review and assess Manitoba Hydro's capital and operation & maintenance (O&M) cost estimates for Conawapa G.S. and Keeyask G.S., including the adequacy of management reserves for the projects.

2. Review and assess Manitoba Hydro's construction indirect costs including access roads, campsites, and off-site mitigation costs for Conawapa G.S. and Keeyask G.S.

3. Review and assess Manitoba Hydro's construction management, schedule, and contracting plans for the design, engineering, procurement, construction, start up, commissioning, testing, and commercial operation of Conawapa G.S. and Keeyask G.S.

4. Review and assess Manitoba Hydro's capital cost and O&M cost estimates for wind, natural gas combined cycle gas turbines, and solar facilities.

5. Review and assess Manitoba Hydro's construction management plans, schedule, and contracting methods for the design, engineering, procurement, construction, start up, commissioning, testing, and commercial operation for wind, natural gas combined cycle gas turbines, and solar facilities.

6. Review Manitoba Hydro's capital expenditure forecasts CEF 13/CEF 12/CEF 11/CEF 10/CEF 9 and explore any significant factors that led to cost increases over successive forecasts.

7. Provide a historical perspective on the construction cost components of other Lower Nelson River hydraulic generating stations (Limestone/Long Spruce/Kettle) and analyze the major components of direct cost, including:

    (a) Spillways/dams/dikes;

    (b) Powerhouses; and

    (c) Turbines and generators;

    and compare these to the Keeyask and Conawapa G.S. costs for these components.

8. Analyze Manitoba Hydro's justifications for increasing direct costs and for increasing indirect costs with respect to:

    (a) Labour productivity and shortages;

    (b) Competition with other large civil projects in Canada;

    (c) Remote location;

    (d) Northern and First Nation jobs; and

    (e) Other contractual hiring constraints.

9. Please provide a high level assessment of the construction planning and management of the construction costs of the new Preferred Development Plan projects, including the experience gained from the Wuskwatim project.

10. Upon prior approval by the NFAT Panel, address any other issues that may be identified in reviewing Manitoba Hydro's evidence or are requested by the NFAT Panel.

POWER ENGINEERS

Transmission Line Construction and Management

1. Review and assess the completeness and reasonableness of Manitoba Hydro's AC transmission line capital cost and O&M estimates including the adequacy of management reserves for the project.

2. Review and assess the completeness and reasonableness of Manitoba Hydro's AC transmission line construction indirect costs, including access roads, campsites, and off-site mitigation costs.

3. Review and assess Manitoba Hydro's construction management, schedule, and contracting plans for the design, engineering, procurement, construction, start up, commissioning, testing, and commercial operation of the AC transmission system.

4. Review and assess Manitoba Hydro's cost estimating risks and risk management practices, sensitivity analysis in construction cost estimates, contingencies, and construction cost indices for the AC transmission system.

5. Provide comparable estimates of costs for each of the foregoing new transmission projects, including Bipole III as suggested by Manitoba Hydro's NFAT filings.

6. Review and assess Manitoba Hydro's estimate for the cost of construction of U.S. transmission infrastructure to facilitate sales into MISO.

7. Review and assess the completeness and reasonableness of the technical aspects of Manitoba Hydro's existing and proposed AC & DC transmission system .

8. Define the average energy flow and transmission losses from Keeyask and Conawapa G.S. to Southern Manitoba for domestic load during peak and off-peak times with:

   (a) Bipoles I and II only; and

   (b) Bipoles I II and III.

9. Define the average energy flow and incremental transmission losses for exports into MISO during peak and off-peak time with:

   (a) Bipoles I and II plus AC to border; and

   (b) Bipoles I, II and III plus AC to border.

10. Provide an assessment of MISO transmission constraints that:

    (a) Require new interconnections; and/or

    (b) Require Manitoba Hydro's financial participation in US transmission project(s).

11. Provide an analysis and justification of Manitoba Hydro's need for additional North-South AC transmission when Conawapa comes on-line.

12. Review and assess Manitoba Hydro's technical need for the cost of construction of U.S. transmission infrastructure to facilitate sales into MISO.

13. Upon prior approval by the NFAT Panel, address any other issues that may be identified in reviewing Manitoba Hydro's evidence or are requested by the NFAT Panel.

LA CAPRA ASSOCIATES

Power Resource Planning and Economic Evaluation

1. From a supply perspective, assess the extent to which the Plan addresses the reliability and security requirements of Manitoba's electricity supply.

2. Assess whether Manitoba Hydro's approach to comparing generation sequences follows sound industry practice.

3. Review reservoir operations of Lake Winnipeg for optimal value.

4. Review Manitoba Hydro's NFAT filings with respect to the Lake Winnipeg and Upper Nelson River Water Regime change and the potential mitigation costs to the NFAT projects.

5. Review the potential global warming impacts on water supply/river flows/lake and reservoir evaporation.

6. Develop power resource plans and alternatives, including identifying other scenarios that could potentially compete on an economic basis with Manitoba Hydro's Preferred Development Plan.

7. Incorporate exports (bilateral contracts and opportunity market pricing) into power resource planning.

8. Evaluate the accuracy and completeness of Manitoba Hydro's export assumptions into MISO and other jurisdictions.

9. Comment on the practical role of merchant trading and energy imports.

10. Examine the No New Generation scenario and the potential for extended use of imports to meet Manitoba Hydro's domestic load requirements.

11. For all scenarios addressed, define the lower quartile, median and upper quartile impacts of natural gas supply pricing, coal pricing and wind pricing.

12. Address the relative generation and integration costs of hydro, wind, natural gas turbines (single-cycle and combined-cycle) and Demand-Side Management.

13. Assess the maximum deferral prospects for Keeyask G.S. and/or Conawapa G.S.

14. Comment on climate change impacts on energy supply and demand.

15. Test Manitoba Hydro's alternative scenarios and any new scenarios created for drought impacts.

16. Review and assess the reasonableness and completeness of Manitoba Hydro's sensitivity analysis of alternative development plans. Perform additional sensitivity analysis as required.

17. Analyse the In-service cost and rate impact on domestic customers of the Preferred Development Plan and alternatives.

18. Analyse the net and gross marginal cost of the Preferred Plan and Alternatives;

19. Analyse the net present value of hydro power and natural gas generation;

20. Assess the reasonableness of the Weighted Average Cost of Capital (WACC) approach, including consideration of different capital structures.

21. Analyse the Internal Rate of Return (IRR), including an evaluation against hurdle rates.

22. Review Manitoba Hydros IRRs against prior IRR values presented in public filings.

23. Upon prior approval by the NFAT Panel, address any other issues that may be identified in reviewing Manitoba Hydro's evidence or are requested by the NFAT Panel.

Business Case and Risk Assessment

1. Analyse the financial and economic risks of the Preferred Development Plan and export contracts and export opportunity revenues in relationship to alternative development strategies.

2. Assess whether the high-level summaries filed by Manitoba Hydro of net present value and internal rates of return reflect sound assumptions and calculations.

3. Enumerate any special consideration with respect to Crown-owned utility operations.

4. Address estimate uncertainties involving large complex hydro projects.

5. Examine and evaluate the treatment of risk in Manitoba Hydro's development of Power Resource Plans and resource scenario models. Incorporate expert opinions on flood and drought risks and optimal strategy.

6. Analyse the market value of clean energy from hydro power during various seasonal and peak or off-peak periods.

7. Address the future U.S. versus Canadian export opportunities.

8. Review Manitoba Hydro's filings and assess the accuracy, reasonableness and completeness of the relative values that Manitoba Hydro places on capital costs/energy supply.

9. Review the accuracy ,reasonableness and completeness of presented alternative scenarios including an assessment of key variables such as:

   (a) Time Frames [80 years];

   (b) Alternative Time Frames of 20/40 years;

   (c) Interest rates;

(d) Inflation;

(e) Discount rates;

(f) Present value calculations; and

(g) Internal rate of return calculations.

10. Review and compare the discount rate applied in the current analysis with prior discount rates used by Manitoba Hydro to assess consistency and reasonableness of the approach.

11. Review all significant scenarios employing other methodologies, including:

(a) in-service rate impacts; and

(b) the net present value of costs.

12. Within each scenario look for a clear business and value proposition for Manitoba ratepayers as well as Manitoba Hydro.

13. Test each scenario for potential risks, including:

(a) Lower export market prices;

(b) Higher interest rates;

(c) Lower or higher domestic load growth;

(d) Droughts;

(e) Competing technologies;

(f) Fuel price changes;

(g) Carbon pricing;

(h) Government and regulatory policy change;

(i) Construction cost escalator;

(j) Economic conditions;

(k) Infrastructure failure; and

(l) Any other major risks identified.

14. Upon prior approval by the NFAT Panel, address any other issues that may be identified in reviewing Manitoba Hydro's evidence or are requested by the NFAT Panel.

Transmission Economics

1. Review and assess the impact of Manitoba Hydro's transmission positions on Manitoba Hydro's assumptions as to export revenue.

2. Review and assess Manitoba Hydro's contemplated plan to partially fund U.S. transmission infrastructure and the financial benefits to be derived from such plan.

3. Upon prior approval by the NFAT Panel, address any other issues that may be identified in reviewing Manitoba Hydro's evidence or are requested by the NFAT Panel.

Review of Manitoba Hydro's Export Contracts

1. Review and assess Manitoba Hydro's export contracts with U.S. counterparties for:

   (a) Firm energy commitments;

   (b) Firm energy pricing;

   (c) Peak demand opportunity market sales;

   (d) Off-peak period opportunity market sales;

   (e) Adverse water clauses;

   (f) Drought relief;

   (g) Clean energy guarantees;

   (h) Treatment of environmental attributes; and

   (i) Any other commercial obligations in the contracts and the implications on Manitoba Hydro and its counterparties; and

2. Upon prior approval by the NFAT Panel, address any other issues that may be identified in reviewing Manitoba Hydro's evidence or are requested by the NFAT Panel.

Financial Modelling

1. Development a financial model that would have the flexibility to change basic assumptions on factors affecting costs to Manitoba Hydro and MISO utility competitive market alternatives. The model should be able to quickly determine the metrics evaluating the timing and type of resources that could be in the Manitoba Hydro Development Plan, and should meet the following requirements:

   (a) The model is expected to be set up within excel spreadsheets.

   (b) The model will not require detailed market simulation software to be used with each alternative business cases.

(c) The model is expected to be used by La Capra Associates staff to support its independent analysis and report as well as examine cases desired by the NFAT and Interveners.

(d) Model documentation will be prepared.

2. Upon prior approval by the NFAT Panel, address any other issues that may be identified in reviewing Manitoba Hydro's evidence or are requested by the NFAT Panel.

MNP

Macro Environmental Issues

1. Perform a critical analysis of the macro environmental impacts and benefits of Manitoba Hydro's Preferred Development Plan and alternative Plans, specifically, the collective macro-economic consequences of changes to air, water, flora and fauna, including the potential significance of these changes, their equitable distribution within and between present and future generations.

2. Review Manitoba Hydro's NFAT filing with a focus on macro-environmental factors that could impact the economics of the project and alternate scenarios, including:

    (a) Direct greenhouse gas emissions;

    (b) Indirect greenhouse gas emissions;

    (c) Global impacts of projects (including Bipole III);

    (d) MISO wind energy expansion; and

    (e) MISO energy mix shift away from coal.

3. Review Manitoba Hydro's NFAT filings with respect to the need and cost for a sturgeon fishway at either Keeyask G.S. or Conawapa G.S.

4. Review Manitoba Hydro's NFAT filings with respect to the Lake Winnipeg and Upper Nelson River Water Regime change and the potential mitigation costs to the NFAT projects.

5. Review the potential global warming impacts on water supply/river flows/lake and reservoir evaporation.

6. Upon prior approval by the NFAT Panel, address any other issues that may be identified in reviewing Manitoba Hydro's evidence or are requested by the NFAT Panel.

TYPLAN

Socio-economic

1. Perform a critical analysis of the socio-economic impacts and benefits of Manitoba Hydro's Preferred Development Plan and alternative Plans, This should include examination of potential effects to the people of 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, including:

   (a) Economic Impact assessment modelling to determine sector economic impacts to provincial GDP, long term and short term induced employment opportunities;

   (b) Determining gross provincial financial benefits by examining benefits and costs over the life of the project;

   (c) Determining Canadian benefits;

   (d) Northern and aboriginal community-based impacts in terms of employment opportunities, incomes, community tax base, skills development and community business opportunities; and

   (e) Community access improvements and related health, education and cultural benefits.

2. Consider the economic displacement impacts and effects on consumer spending to the extent consumers will face increased electricity rates as a result of the Preferred Development Plan.

3. Identify and evaluate the socio-economic impact of five key alternative scenarios, and provide a comparison table between the Preferred Development Plan and such scenarios.

4. Provide a high-level analysis on how other Canadian jurisdictions maximize provincial economic benefits from the development of large-scale resource projects and assess if the Preferred Plan provides the highest level of socio-economic benefit to Manitobans

5. Upon prior approval by the NFAT Panel, address any other issues that may be identified in reviewing Manitoba Hydro's evidence or are requested by the NFAT Panel.

MORRISON PARK ADVISORS

Commercial Evaluation of Manitoba Hydro's Preferred Development Plan

1. Analyse Manitoba Hydro's Preferred Development plan from a commercial perspective, including:

   (a) Consideration of the overall costs, risks and benefits being assumed by Manitoba Hydro in the pursuit of the Plan, particularly in light of potential alternatives to the Plan which could satisfy provincial and ratepayer objectives (commercial reasonableness of the Plan);

   (b) Consideration of the costs assumed, risks taken, and compensating benefits expected for each relevant stakeholder of Manitoba Hydro, including ratepayers, the Government of Manitoba, Manitoba taxpayers, and others (relative commercial reasonableness of the Plan for various stakeholders);

   (c) Consideration of commercial risks being assumed by Manitoba Hydro as part of its export agreements, and specifically how these risks relate to the risks being taken by Manitoba ratepayers in the event that export agreements do not perform according to optimal scenarios (commercial reasonableness of the export aspects of the Plan in relation to the domestic services portions); and

   (d) Consideration of specific financial impacts and risks being assumed as part of the Plan by the Government of Manitoba and the taxpayers of Manitoba, as they relate to the Province's credit rating, borrowing capacity, potential impact on other budgetary priorities, credit availability, and credit rates in the future.

APPENDIX C

LIST OF MATERIAL

(Pages C-1 to C-24)

Appendix C: List of Material Available for Review for NFAT - Independent Expert - Knight Piésold Ltd.

M:\1\03\00449\01\A\Report\2 - Knight Piesold Expert Review Report (Redacted)\Rev 0\Appendix C- List of Material\[NFAT Review - List of Material Available for Review for Report.xlsx]List

Confidentiality	Document Index	Document Title	Summary or Notes	Key Terms	Relevance to KP Scope
PUB Material					
F	Presentation to Independent Experts by Fillmore Riley	September 4,2013			Some
F	Knight Piésold Expert Scopes of Work			Scope of Work	High
F	Presentation to Independent Experts by LAB and Cathcart Advisors	Independent Expert Consultant Briefing by L.A.B. and Cathcart Advisors September 4,2013			Some
NFAT Process					
F	Terms of Reference			Terms of Reference	High
F	Order in Council				Low
F	Board Orders				Low
F	Panel Members				Low
F	Public Notices				Low
F	Participation by the Public				Low
F	Pre-Hearing Conferences				Low
F	Pre-Hearing Conference May 16, 2013	Transcript dated May 16, 2013			Low
F	Pre-Hearing Conference May 16, 2013	Manitoba Hydro Presentation			Low
F	Pre-Hearing Conference Sept 4, 2013	Pre-Hearing Transcripts September 4, 2013			Low
F	Intervener Applications				Low
Technical Conferences					
F	Technical Conference -- July 15 and 17, 2013	Agenda			Low
F		July 15, 2013 Transcript			Low
F		July 17, 2013 Transcript			Low
F	PowerPoint Presentations	1. Overview of Manitoba Hydro's System			Some
F		2.Overview of MISO Market			Low
F		3.MISO Tariff			Low
F		4.Export Contracts Fundamental To Preferred Plan			Low
F		5.Review of Manitoba Hydro Supply and Demand Tables			Low
F		6.Discussion of Manitoba Hydro's Load Forecast			Low
F		7.NFAT Project Descriptions			High
F		8.Capital Cost Estimates for Keeyask and Conawapa Generating Stations			High
F		9.NFAT Selection of Development Plans			High
F		10.Overview of Confidential vs. Non-Confidential Information			Some
F	Technical Conference -- Sept 5 and Sept 6, 2013	Agenda			Low
F		September 5, 2013 Transcript			Low
F		September 6, 2013 Transcript			Low
F	PowerPoint Presentations	1a Electrical Load Forecast			Low
F		1b Demand Side Management			Low
F		2a MISO Marketplace Export Sales and U.S. Interconnection Update			Low
F		2b Long-term Export Prices			Low
F		3 Power Resource Planning Alternatives and Economic Evaluations			High
F		4a Financial Evaluation of Development Plans			Some
F		4b Business Case and Risk Assessment			Some
F		5 Capital Cost Estimates for Keeyask and Conawapa			High
F		6 Macro-Environmental and Socio-Economic Considerations			Low

Manitoba Hydro Filings - Submission by Manitoba Hydro			
F	MH Submission - Introduction	Introduction	Some
F	MH Submission - Overview	Overview	Some
F	MH Submission - Executive Summary	Executive Summary	Some
F	MH Submission - Table of Contents	Table of Contents	Low
F	MH Submission - Acronyms and Abbreviations	Acronyms and Abbreviations	Low
F	MH Submission - Glossary	Glossary	Low
F	MH Submission - Chapter 1	Introduction	Some
F	MH Submission - Chapter 2	Manitoba Hydro's Preferred Development Plan Facilities	Some
F	MH Submission - Chapter 3	Trends and Factors Influencing North American Electricity Supply	Some
F	MH Submission - Chapter 4	The Need for New Resources	Some
F	MH Submission - Chapter 5	The Manitoba Hydro System, Interconnections and Export Markets	Some
F	MH Submission - Chapter 6	The Window of Opportunity	Some
F	MH Submission - Chapter 7	Screening of Manitoba Resource Options	Some
F	MH Submission - Chapter 8	Determination and Description of Development Plans	Some
F	MH Submission - Chapter 9	Economic Evaluations - Reference Scenario	Some
F	MH Submission - Chapter 10	Economic Uncertainty Analysis - Probabilistic Analysis and Sensitivities	Some
F	MH Submission - Chapter 11	Financial Evaluation of Development Plans	Some
F	MH Submission - Chapter 12	Economic Evaluations - 2013 Update On Selected Development Plans	Some
F	MH Submission - Chapter 13	Integrated Comparisons of Development Plans - Multiple Account Analysis	Some
F	MH Submission - Chapter 14	Conclusions	Some
F	MH Submission - Chapter 15	Implementation and Risk Management Plan for Preferred Development Plan	Some
F	MH Submission - Appendix A	Integrated Financial Forecast (IFF 2012)	High
F	MH Submission - Appendix B	Manitoba Hydro 2011/12 Power Resource Plan	Some
F	MH Submission - Appendix C	2012 Electric Load Forecast	Low
F	MH Submission - Appendix D	2013 Electric Load Forecast	Low
F	MH Submission - Appendix E	2013-2016 Power Smart Plan	Low
F	MH Submission - Appendix F	Economic Outlook 2012–2033	Low
F	MH Submission - Appendix G	Economic Outlook 2013–2034	Low
F	MH Submission - Appendix H	Corporate Strategic Plan 2012–2013	Some
F	MH Submission - Appendix I	Manitoba Hydro Electric Board Annual Report (2011/2012)	Some
F	MH Submission - Appendix J	10/11 Sustainable Development Report	Some
F	MH Submission - Appendix K	Manitoba Hydro Climate Change Report Fiscal Year 2012–2013	Low
F	MH Submission - Appendix 1.1	TOR and OIC	
F	MH Submission - Appendix 2.1	Lake Sturgeon: Mitigation and Enhancement	Low
F	MH Submission - Appendix 2.2	Joint Keeyask Development Agreement - Benefits Summary	Some
F	MH Submission - Appendix 2.3	Economic Impact Assessment	Some
F	MH Submission - Appendix 2.4	Developing the Keeyask and Conawapa Capital Cost Estimates	High
F	MH Submission - Appendix 3.1	Long-Term Price Forecast for Manitoba Hydro's Export Market in MISO - The Brattle Group	Low
F	MH Submission - Appendix 4.1	Manitoba Hydro Generation Planning Criteria	Some
F	MH Submission - Appendix 4.2	Manitoba Hydro Supply and Demand Tables	Low
F	MH Submission - Appendix 4.3	Demand Side Management Potential Study	Low
F	MH Submission - Appendix 5.1	MISO Corporate Fact Sheet July 2012	Low
F	MH Submission - Appendix 5.2	MISO Market Products, Operation and Locational Marginal Pricing	Low
F	MH Submission - Appendix 5.3	Electricity Market Overview for Manitoba Hydro's Export Market in MISO	Low

	MH Submission - Appendix 6.1	Summary of Terms and Conditions of Export Contracts			
F					Low
F	MH Submission - Appendix 7.1	Emerging Energy Technology Review			Some
	MH Submission - Appendix 7.2	Range of Resource Options			Some
	MH Submission - Appendix 7.3	Life Cycle Greenhouse Gas Assessment Overview			Low
	MH Submission - Appendix 7.4	Capacity Value of Wind Resources			Some
	MH Submission - Appendix 9.1	High Level Development Plan Comparison Table			High
	MH Submission - Appendix 9.2	Description of SPLASH Model			Some
	MH Submission - Appendix 9.3	Economic Evaluation Documentation			Some
	MH Submission - Appendix 11.1	Net Capital Expenditures			High
	MH Submission - Appendix 11.2	Projected Escalation, Interest and Exchange Rates			High
	MH Submission - Appendix 11.3	Average Unit Revenue/Cost			High
	MH Submission - Appendix 11.4	Pro Forma Financial Statements - Volume 1 of 2			Some
	MH Submission - Appendix 11.4	Pro Forma Financial Statements - Volume 2 of 2			Some
	MH Submission - Appendix 11.5	Enlarged Figures 11.1 — 11.7			Some
	MH Submission - Appendix 13.1	NFAT Reliability Evaluation			Some
	MH Submission - Appendix 14.1	Sustainable Development and Clean Energy			Some
	MH Submission - Appendix 15.1	Keeyask Aboriginal Partnership Business Risks			Some
Information Requests - Round 1					
F	Round 1 cover letter dated November 8, 2013				Low
F	Consumers Association of Canada (CAC) Responses	CAC/MH I-001	corporate policy/standard, fall 2009, for major capital projects	Keeyask and Conawapa Capital Cost, P50	High
F		CAC/MH I-002a	P50 level addresses the majority of uncertainty	Keeyask and Conawapa Capital Cost, P50	High
F		CAC/MH I-002b	P values used by other Canadian utilities with hydro-electric facilities	Keeyask and Conawapa Capital Cost, P50	High
F		CAC/MH I-003a	$4.1 Base Dollar cost for Keeyask in 2012 dollars	Keeyask Cost	High
F		CAC/MH I-003b	NFAT economic analysis did not consider capital cost estimates associated with KIP	Keeyask Cost	Some
F		CAC/MH I-004	Appendix 11.2	Interest and escalation rates	Low
F		CAC/MH I-005	Escalation reserve	Keeyask and Conawapa Capital Cost, escalation reserve	High
F		CAC/MH I-006	schedule that sets out the derivation of the $0.12 B Escalation Reserve	Keeyask Capital Cost, escalation reserve	High
F		CAC/MH I-007	a schedule that sets out the derivation of the $0.38 Labour Reserve for Keeyask	Keeyask Capital Cost, labour reserve	High
F		CAC/MH I-008	$0.2 B for "Interest on MH Equity"	Keeyask Capital Cost, interest on equity	High
F		CAC/MH I-009	equity ownership arrangement	Conawapa Capital Cost, interest on equity	High
F		CAC/MH I-010	$3.7 B vs. $4.1 B	Keeyask Capital Cost	High
F		CAC/MH I-011a	$3.7 B vs. $4.1 B	Keeyask Capital Cost	High
F		CAC/MH I-011b	$3.4 B vs. $2.9 B	Keeyask Capital Cost	High
F		CAC/MH I-012a	29% of the $3.05 B Point Estimate awarded	Keeyask Capital Cost	High
F		CAC/MH I-012b	approximately 55% competitively tendered	Keeyask Capital Cost	High
F		CAC/MH I-013	$6.1 B vs. $5.7 B	Conawapa Capital Cost	High
F		CAC/MH I-014a, b	proposed transmission solution for potential shortfall is the north-south upgrades	Transmission reliability and cost, HVDC system	Low
F		CAC/MH I-015	Transmission column from Appendix 9.3	Keeyask GOT, Conawapa GOT	Some
F		CAC/MH I-016a	full in service cost	North-South Transmission Cost	Some
F		CAC/MH I-016b	$498 M value with the $395.6 M	North-South Transmission Cost	High
F		CAC/MH I-016c	Breackdown, interest, escalation	North-South Transmission Cost	High
F		CAC/MH I-017a	$350 M capital cost	Manitoba-Minnesota Transmission	Some
F		CAC/MH I-017b	$350 M vs $204.8 M	Manitoba-Minnesota Transmission	Some
F		CAC/MH I-018a	Manitoba vs US	Manitoba-Minnesota Transmission	Low
F		CAC/MH I-018b	reconcile	Manitoba-Minnesota Transmission	Low
F		CAC/MH I-019	230 kV vs 500 kV	Manitoba-Minnesota Transmission	Low
F		CAC/MH I-020	Manitoba vs US	Manitoba-Minnesota Transmission	Low
F		CAC/MH I-021a	$507M (2013 US $)	US portion of the 750 MW interconnection	Low
F		CAC/MH I-021b	reconcile	Great Northern Transmission Line Project	Low
F		CAC/MH I-022a	no equity loans to the KCN	loans to KCNs by Manitoba Hydro	Some
F		CAC/MH I-022b	sensitivity of the financial projections to KCN partner can choose to invest as a common-unit partner or a preferred-unit partner	KCNs	Some

F		CAC/MH I-023	the KCN have the opportunity to take on equity loans to obtain a larger number of shares than they otherwise would be able to for the amount of cash equity they may have available	Keeyask Aboriginal Partnership Business Risks	Low
F		CAC/MH I-024		KHLP distributions	Low
F		CAC/MH I-025	finalized	adverse effects agreements	Low
F		CAC/MH I-026a	230 kV US interconnection is subject to final desigr	export capacity of new 230 kV line	Low
F		CAC/MH I-026b	450 MW of the 750 MW	Manitoba-Minnesota Transmission	Low
F		CAC/MH I-027a, b	MISO tariff in the USA, revenue sharing on tariff	Manitoba-Minnesota Transmission	Low
F		CAC/MH I-0028	comparison to Stats Canada	Economic Outlook	Low
F		CAC/MH I-029		US Load Growth	Low
F		CAC/MH I-030		North American Electricity Supply	Low
F		CAC/MH I-031		750 kV interconnection	Low
F		CAC/MH I-032a, b		MISO price and transmission constraints	Low
F		CAC/MH I-033	Figure 3.13 is taken from Slide 33 of Appendix 3.1	Price Forecast	Low
F		CAC/MH I-034		Price Forecast	Low
F		CAC/MH I-035		Price Forecast	Low
F		CAC/MH I-036	PUB/MH I-286a) and PUB/MH I-013b)	Price Forecast, Need for Wuskwatim Project	Low
F		CAC/MH I-037a, b	Appendix 11.3, Export Revenue	Price Forecast, Need for Wuskwatim Project	Low
F		CAC/MH I-038	Industry Leading?	Need for New Resources	Low
F		CAC/MH I-039a, b, c		Electric Load Forecast	Low
F		CAC/MH I-040a	price elasticities, PUB/MH I-83	Electric Load Forecast	Low
F		**CAC/MH I-040b**	**annual percentage increase in CPI and MH rates**	**Electric Load Forecast**	**Some**
F		CAC/MH I-040c	PUB/MH I-256	Electric Load Forecast	Low
F		CAC/MH I-041a, b, c	refrigerators, lighting and clothes drying	Electric Load Forecast	Low
F		CAC/MH I-042a, b	Residential Sector	Electric Load Forecast	Low
F		CAC/MH I-043	persistence in DSM savings	Electric Load Forecast	Low
F		CAC/MH I-044	annual growth	Electric Load Forecast	Low
F		CAC/MH I-045	Medium and Large classes	Electric Load Forecast	Low
F		CAC/MH I-046	five-year average use for each customer class	Electric Load Forecast	Low
F		CAC/MH I-047a, b	new codes and standards	Electric Load Forecast	Low
F		CAC/MH I-048	no DSM programs in the future	Electric Load Forecast	Low
F		**CAC/MH I-049**	**Manitoba Hydro Policy G195, Capacity Criterion, Energy Criterion, definitions**	**Generation Planning Criteria**	**Some**
F		CAC/MH I-050a, b	CAC/MH I-051	12% Reserve	Low
F		**CAC/MH I-051**	**PPD#12/05 titled Review of Generation Planning Criteria**	**Generation Planning Criteria**	**Some**
F	PPD#12/05	Review of Generation Planning Criteria	Resource Planning & Market Analysis Department	Generation Planning Criteria	Low
F		CAC/MH I-052a, b, c	capacity reserves required under export contracts	Supply and Demand Tables	Low
F		CAC/MH I-053a, b		Supply and Demand Tables	Low
F		CAC/MH I-054a, b, c	lowest recorded coincident water supply conditions	Dependable Energy	Low
F		CAC/MH I-055	limitations on Imports	Generation Planning Criteria	Low
F		CAC/MH I-056	Import Contracts	Supply and Demand Tables	Low
F		CAC/MH I-057	Dependable Energy Imports	Supply and Demand Tables	Low
F		CAC/MH I-058	Winter Peak	Need for New Resources	Low
F		CAC/MH I-059	Imports with 750 MW US interconnection	Supply and Demand Tables	Low
F		CAC/MH I-060	definition for Contracted Exports	Supply and Demand Tables	Low
F		CAC/MH I-061	CAC/MH I–081	Supply and Demand Tables	Low
F		CAC/MH I-062	loss of load expectation or LOLE	Need for New Resources	Low
F		CAC/MH I-063	opportunities for supply-side enhancements	Need for New Resources	Low
F		CAC/MH I-064		Current Import Contracts	Low
F		**CAC/MH I-065**	**statutory operating restrictions on the natural gas units**	**Natural Gas Operation Restrictions**	**Some**
F		**CAC/MH I-066**	**not been assessed**	**Coal to natural gas**	**Some**
F		CAC/MH I-067	Energy Service Agreements	Imports	Low
F		CAC/MH I-068	Wuskwatim Project NFAT	Firm Export and Import limits	Low
F		CAC/MH I-069	Current maximum export capability	Firm Export and Import limits	Low
F		CAC/MH I-070	Ontario and Saskatchewan	Firm Export and Import limits	Low
F		CAC/MH I-071a, b	12% planning reserve margin include the 150 MW of contingency reserve	12% Reserve	Low
F		CAC/MH I-072	sale of ancillary services requires the use of transmission	Ancillary Services	Low
F		CAC/MH I-073a, b	Reach all	MISO Market	Low
F		CAC/MH I-074	energy and ancillary services markets	MISO Market	Low
F		CAC/MH I-075a, b	Minnesota Hub (MINN HUB) Average Monthly All Hours Price	MISO Market	Low
F		CAC/MH I-076a, b	new transmission interconnections with Saskatchewan	Saskatchewan Transmission	Low

F		CAC/MH I-077	new export sales contracts has fixed annual prices for capacity and energy	Window of Opportunity	Low
F		CAC/MH I-078	surplus energy available for export	Window of Opportunity	Low
F		CAC/MH I-079	75- MW two routes, 250 MW one route considered	new transmission alternatives	Low
F		CAC/MH I-080	Long Term Export Commitments	Window of Opportunity	Low
F		CAC/MH I-081	Winter Peak Capacity Exports	Need for New Resources	Low
F		CAC/MH I-082		Transmission Charges	Low
F		**CAC/MH I-083**	**Additional DSM, NFAT Business Case Chapter 7 Table 7.1**	**Small Scale Generation**	**Some**
F		CAC/MH I-084	Materials from IPSOS	Resource Options	Low
F		**CAC/MH I-085**	**US EIA was a real cost of capital of 6.6%.**	**Discount Rate on Levelized Cost**	**Some**
F		CAC/MH I-086	Maximum amount of import	Dependable Energy	Low
F		**CAC/MH I-087a**	**Table 7.3 under "Resource Lead Time"**	**Earliest In-Service Date**	**Some**
F		CAC/MH I-088	Short Term Gap	Imports	Low
F		CAC/MH I-089a, b, c	percentage investment and percentage ownership	Manitoba-Minnesota Transmission	Low
F		CAC/MH I-090	108MW/300MW	Sale to WPS	Low
F		CAC/MH I-091	No 108MW WPS	K19/C25/750 MW plan	Low
F		CAC/MH I-092	implications of commiting to a 750 MW	K19/C25/750 MW plan	Low
F		CAC/MH I-093		K19/C25/750 MW plan	Low
F		CAC/MH I-094	No 250 MW plan	K19/C25/750 MW plan	Low
F		CAC/MH I-095		K19/C25/250 MW plan	Low
F		CAC/MH I-096a, b		K19/C25/250 MW plan	Low
F		CAC/MH I-097		100 MW WPS sale	Low
F		CAC/MH I-098		Minnesota Power Energy Exchange Agreement	Low
F		CAC/MH I-099	sale agreements included in development plans	Sales Agreements	Low
F		CAC/MH I-100	no investment in 750 MW line	WPS 300 MW contract	Low
F		CAC/MH I-101		Economic Evaluations	Low
F		CAC/MH I-102	Manitoba Hydro's corporate policy	Economic Evaluations	Low
F	CAC/MSOS/MH/NCN 1 - NFAAT - 3a	Hurdle Rate Policy		Hurdle Rate Policy	Low
F		**CAC/MH I-103**	**Replacement of equipment for Keeyask G.S.**	**Fixed O&M Costs for Keeyask**	**Some**
F		**CAC/MH I-104**	**6.3 % cost of Debt**	**Cost of Debt, Bonds**	**Some**
F		CAC/MH I-105	PUB/MH I-151c	Cost of Equity	Low
F		CAC/MH I-106a		On-Peak All-in Product	Low
F		CAC/MH I-107	Brattle Group	Energy Price	Low
F		CAC/MH I-108	CSI	Energy Price	Low
F		CAC/MH I-109		Long-Term Export Contracts	Low
F		CAC/MH I-110	marginal cost methodology	Economic Evaluation	Low
F		CAC/MH I-111	80% of total incremental investment and a return to a 75% debt ratio	Economic Evaluation	Low
F		CAC/MH I-112a	not incremental analysis	IFF	Low
F		CAC/MH I-112b	Table 13.3, Chapter 13, Section 13.3.3, page 29	Multiple Accounts Cost Benefit Analysis	Low
F		CAC/MH I-113a, b	costs and benefits that are common to all development plans are not included in the analysis	Cash-Flow analysis	Low
F		CAC/MH I-114	20-year history of water rental fees	Water Rental	Low
F		CAC/MH I-115	Excel	Table 001 through Table 405	Low
F		CAC 115 attachment			Low
F		CAC/MH I-116	Excel	Table 433 through Table 444	Low
F		**CAC 116 attachment**			Low
F		CAC/MH I-117		CCGT/C26 and K22/C29	Low
F		CAC/MH I-118a, b		NPV for 750 MW interconnection	Low
F		CAC/MH I-119a, b	capital tax treatment for the US portion of the interconnection	Capital Tax	Low
F		CAC/MH I-120a, b		Plan 16	Low
F		CAC/MH I-121	Order 119/13	NA	Low
F		CAC/MH I-122	history of water rental rates	Water Rental	Low
F		CAC/MH I-123	sensitivity	Water Rental	Low
F		CAC/MH I-124	22.3 is the mean of the 9-point representation in Figure 2.3 of Appendix 9.3	Energy Price	Low
F		CAC/MH I-125a, b	interest rates in Figure 2.12 on page 56 of Appendix 9.3 do not include the 1% debt guarantee fee, CAC/MH I-125a	Interest Rates	Low
F		CAC/MH I-126	CAC/MH I-104	Interest Rates	Low
F		**CAC/MH I-127**	**Nominal and Real, schedule demonstrates the derivation of the low and high discount rate or weighted average cost of capital**	**Interest Rates**	**High**

F	**CAC/MH I-128**	**real capital cost escalation is separate from the general inflation**	**Escalation of Capital Costs**	**High**
F	CAC/MH I-129a, b, c	Manitoba Hydro is responsible for 2/3's of the capital and O&M costs for 750 MW interconnection	Plan 15	Low
F	CAC/MH I-130	obligations to deliver firm power	Drought Impact	Low
F	CAC/MH I-131	Figures 10.13 and 10.14	Plan 4	Low
F	CAC/MH I-132	costs savings from the deferral	Deferral	Low
F	CAC/MH I-133	Figures 2.7.7 through to 2.7.24	S-Curves	Low
F	**CAC/MH I-134**	**labour reserve and the escalation reserve**	**Capital Costs for Keeyask**	**Some**
F	**CAC/MH I-135**	**labour reserve and the escalation reserve**	**Capital Costs for Conawapa**	**Some**
F	CAC/MH I-136	$134 M aTrans-US T/L represents the projected costs for Manitoba portion of 250 MW line	Trans-US T/L	Low
F	CAC/MH I-137	$628 M shown on p. 6 under Trans-US T/L reflects 100% of the Manitoba portion and 18% of the total capital cost of the US portion	Trans-US T/L	Low
F	CAC/MH I-138	40% and 66.67%	Trans-US T/L	Low
F	CAC/MH I-139	13 years	Residential rates	Low
F	CAC/MH I-140	Projected Residential Energy Charge per plan	Residential rates	Low
F	CAC/MH I-141a, b	PUB/MH I-149(a)	Residential rates	Low
F	CAC/MH I-142	PUB/MH I-149(a)	Residential rates	Low
F	CAC/MH I-143		Provincial GDP	Low
F	CAC/MH I-144a, b, c	borrowing plans	Manitoba Hydro's historical borrowing	Low
F	CAC/MH I-145a, b	review with credit rating agencies, credit rating report exerpts	Credit Rating	Low
F	**CAC/MH I-146**	**debt/equity (75:25), interest coverage (>1.20) and capital coverage (>1.20) in November 2012**	**75:25 debt:equity ratio**	**Some**
F	CAC/MH I-147	MIPUG/MH I-6(c)(ii)	Drought Impact	Low
F	**CAC/MH I-148a, b**	**Actual and Forecasr Electricity Base Capital Expenditures**	**Annual Capital Expenditures, CEF**	**Some**
F	CAC/MH I-149	reduction in DSM	DSM	Low
F	CAC/MH I-150	Comparison of the Projected Economic Variables	Economic Evaluations	Low
F	**CAC/MH I-151a, b, c**		**Capital Cost of the 250 and 750 MW interconnection**	**Some**
F	CAC/MH I-152a, b, c, d	Marvin Shaffer CV	Multiple Account Benefit-Cost Analysis	Low
F	CAC/MH I-153a		Multiple Account Benefit-Cost Analysis	Low
F	CAC/MH I-154a, b		Reliability without Bipole I&II	Low
F	CAC/MH I-155a, b		customer rate impacts	Low
F	CAC/MH I-156a	Benefit-cost analysis not economic impact analysis	Multiple Account Benefit-Cost Analysis	Low
F	CAC/MH I-157a, b, c, d, e	Communities, electricity usage	Four KCNs	Low
F	CAC/MH I-158	no disproportional net benefits or costs between plans	Multiple Account Benefit-Cost Analysis	Low
F	CAC/MH I-159		Customer Account	Low
F	CAC/MH I-160		Manitoba Hydro Net Revenue S-Curves	Low
F	CAC/MH I-161a, b		Manitoba Hydro Net Revenue S-Curves	Low
F	**CAC/MH I-162a, b**	**Keeyask and Conawapa if Lake Sturgeon listed under SARA, potential requirements for fish protection, CAC/MH I-231b**	**Lake Sturgeon**	**Some**
F	CAC/MH I-163	PUB/MH I-149(a)	75:25 debt:equity ratio	Low
F	CAC/MH I-164a, b	standard deviation of load	Electric Load Forecast	Low
F	CAC/MH I-165a, b		Affordability	Low
F	**CAC/MH I-166**	**construction period 10 years vs final decision time to completion of 8 years**	**Conawapa Inservice Date**	**Some**
F	**CAC/MH I-167a**	**Rationale for P50 standard**	**P50**	**High**
F	**CAC/MH I-167b**	**Alternative capital cost amounts are considered within the plan analysis**	**P50**	**High**
F	CAC/MH I-168a, b	growth of 0.4%	Energy Demand Growth	Low
F	CAC/MH I-169a, b	1.5% to 2.0% greater than Canadian CPI	Rate Increases	Low
F	CAC/MH I-170		Price Elasticity	Low
F	CAC/MH I-171	not explicitly incorporated	Price Elasticity	Low
F	CAC/MH I-172a, b	CAC/MH I-170	Price Elasticity	Low
F	CAC/MH I-173	PUB/MH I-256	Price Elasticity	Low
F	CAC/MH I-174a, b	macro-economic variables, CAC/MH I-127	Economic Evaluation	Low
F	CAC/MH I-175a		Impact of Discount Rate	Low
F	CAC/MH I-176a, b		Economic Uncertainty Analysis	Low
F	CAC/MH I-177		S-Curves	Low
F	CAC/MH I-178		S-Curves	Low

F		CAC/MH I-179a, b, c	Gas Less Flexible for expansion argument, more flexible for contraction, optionality in PUB/MH I-279	Gas Options Flexibility	Some
F		CAC/MH I-181a, b	even-annual rate increase	Rate Increases	Low
F		CAC/MH I-182a, b	PUB/MH I-065 and PUB/MH I-156a	Discount Rate Sensitivity	Some
F		CAC/MH I-183		DSM Sensitivity	Low
F		CAC/MH I-184a		S-Curves	Low
F		CAC/MH I-185	Monthly Degree Days Heating History in Winnipeg	Rate Impact	Low
F		CAC/MH I-186a, b	Heat Billed	Rate Impact	Low
F		CAC/MH I-187a, b	Customers by Dwellings	Rate Impact	Low
F		CAC/MH I-188a, b		Rate Impact	Low
F		CAC/MH I-189a, b	dwelling types or heating types for residential customers	Rate Impact	Low
F		CAC/MH I-190	inclining block rates	Rate Impact	Low
F		CAC/MH I-191a, b	income range	Rate Impact	Low
F		CAC/MH I-192a, b	income range	Rate Impact	Low
F		CAC/MH I-193a, b	ownership	Rate Impact	Low
F		CAC/MH I-194	CAC/MH I-139	Residential Tariff changes	Low
F		CAC/MH I-195a, b, c	Bipole III costs are common to all development plans	Bipole III	Low
F		CAC/MH I-196		Load Growth Rates	Low
F		CAC/MH I-197		EIA reference case	Low
F		CAC/MH I-198		EIA reference case	Low
F		CAC/MH I-199a, b	MISO produce demand forecasts	MISO	Low
F		CAC/MH I-200	incorporate the net load impact of approved DSM	load growth projections	Low
F		CAC/MH I-201		Carbon Price, MISO	Low
F		CAC/MH I-202		RPS	Low
F		CAC/MH I-203a, b, c		Carbon Price, Electricity Price Forecast	Low
F		CAC/MH I-204a, b	natural gas price spikes of 2005 and 2008 hurricanes	Natural Gas Prices	Some
F		CAC/MH I-205	annual price volatility at Henry Hub has been high	Natural Gas Prices	Some
F		CAC/MH I-206		Natural Gas Prices	Low
F		CAC/MH I-207a, b, c	EIA does not produce wholesale electricity price forecasts	Price Forecasts	Low
F		CAC/MH I-208a, b, c, d	EIA does not produce wholesale electricity price forecasts	Price Forecasts	Low
F		CAC/MH I-209		Price Forecasts	Low
F		CAC/MH I-210	value of RECs	Price Forecasts	Low
F		CAC/MH I-211	RPS and TL ROR	Price Forecasts	Low
F		CAC/MH I-212	reduced transmission incentives for investor-owned utilities in the	FERC incentives on electric transmission	Low
F		CAC/MH I-213	MISO's Manitoba Hydro Wind Synergy Study (MHWSS) showed that prices will be affected by Manitoba Hydro's Preferred Development Plan.	Wind Synergy Study	Some
F		CAC/MH I-214a	EIA provides data on generation sources by state	Coal Generation from Minnesota and Wisconsin	Low
F		CAC/MH I-215a, b		MISO Wind and Coal	Low
F		CAC/MH I-216	0.75 tonnes of CO2 / MWh	GHGs	Low
F		CAC/MH I-217		GHGs	Low
F		CAC/MH I-218		RPS Indiana	Low
F		CAC/MH I-219		Fermi nuclear plant	Low
F		CAC/MH I-220a, b	NA - Order 119/13	End use of Electricity	Low
F		CAC/MH I-221		Domestic load driven	Low
F		CAC/MH I-222		DSM/Power Smart	Low
F		CAC/MH I-223a, b		DSM	Low
F		CAC/MH I-224ai, aii, aiii, aiv, b	NA - Order 119/13	DSM	Low
F		CAC/MH I-225a, b	Sensitivity	DSM	Low
F		CAC/MH I-226a, b	biomass heating and geothermal heating	DSM	Low
F	Attachment CAC/MH I-0226b	Heating with Biomass	Manitoba Hydro Biomass Fuel Heating Study		Low
F		CAC/MH I-227a	Wind/Gas plan inherently assumes optimization with Manitoba Hydro's assets	Wind/Gas plan	Some
F		CAC/MH I-227b	Biomass heating to reduce winter electricity	Wind/Gas plan	Low
F		CAC/MH I-228a, b, c	Quantitative and Qualitative criteria, Table	Decision-Making Process	Some
F		CAC/MH I-229a, b	Appendices 7.1 Emerging Energy Technology Review. Manitoba Hydro does not expect there is potential for appreciable positive synergies between technologies.	solar, wind, biomass and DSM	Some
F		CAC/MH I-230a, b, c, d	macro environmental effects	Multiple Account Analysis	Low
F		CAC/MH I-231a	Macro-environmental Comparison of Resource Options	Multiple Account Analysis, Lake Sturgeon, Macro Environmental	Some
F		CAC/MH I-231b	SARA, one year delay, consequance dollars	Multiple Account Analysis, Lake Sturgeon	Some
F		CAC/MH I-232	CAC/MH I-231(a)	Multiple Account Analysis	Low
F		CAC/MH I-233ai, aii, b		bequest value analysis	Low
F		CAC/MH I-234	withdrawn	ISO	Low

F		CAC/MH I-235a, b		DSM	Low
F		CAC/MH I-236		KCN referendum	Low
F		CAC/MH I-237a, b	withdrawn	post-impoundment risk	Low
F		CAC/MH I-238a, b	CAC/MH-231(a)	Macro Environmental	Low
F		**CAC/MH I-238c**	**Construction effects**	**Lake Sturgeon**	**Some**
F		CAC/MH I-238d	CAC/MH-231(a)	Macro Environmental	Low
F		CAC/MH I-239a, b	CAC/MH-231(a)	Macro Environmental	Low
F		CAC/MH I-240a, b, c	NERC growth rate	Demand Growth	Low
F		CAC/MH I-241	PUB/MH I-256	Manitoba prices and Manitoba load	Low
F		CAC/MH I-242		Gross Firm Energy	Low
F		CAC/MH I-243	CAC/MH I-231(a)	Woodland Caribou	Low
F		CAC/MH I-244	PUB/MH I-263(a)	DSM	Low
F	Attachment 1 CAC/MH I-244	Demand Side Management Potential Study – DRAFT REPORT	ENERNOC	DSM	Low
F		CAC/MH I-245	CAC/MH I-084, Poli	Social Acceptibility	Low
F		CAC/MH I-246a, b	conclusion of the FLCN	Keeyask Partnership	Low
F		**CAC/MH I-247**	**wind and geo-thermal**	**Social Acceptibility**	**Some**
F		CAC/MH I-248	adverse effects is more appropriately canvassed in the CEC proceeding	trap, fish and hunt	Low
F		CAC/MH I-249	Multiple Account Benefit-Cost Analysis	Aboriginal Traditional Knowledge	Low
F		CAC/MH I-250	Dr. Shaffer info referenced in Chapter 13	KCN	Low
F		CAC/MH I-251a, b	NA - Order 119/13	Lake Sturgeon	Low
F	**Consumers Association of Canada/Green Action Centre (CAC GAC) Responses**	CAC_GAC/MH I-001a, b	Section 4.2.2	Power Smart Plan	Low
F		CAC_GAC/MH I-002a, b		DSM, Market segmentation	Low
F		CAC_GAC/MH I-003a, b, c		DSM, Residential Heating	Low
F		CAC_GAC/MH I-004a, b, c, d, e		DSM, Residential Lighting	Low
F		CAC_GAC/MH I-005a, b, c, d, e		DSM, Measures	Low
F		CAC_GAC/MH I-006		DSM, Economic screen inputs	Low
F		CAC_GAC/MH-007a, b, c		DSM, Methodology/TRC	Low
F		CAC_GAC/MH I-008a, b		DSM	Low
F		CAC_GAC/MH I-009		DSM, Technological progress	Low
F		CAC_GAC/MH I-010		DSM, Screening level	Low
F		CAC_GAC/MH I-011a, b, c	Order 119/13 the PUB	DSM, average benefit/cost ratio	Low
F		CAC_GAC/MH I-012a, b	EnerNOC Utility Solutions	DSM, Baseline	Low
F		CAC_GAC/MH I-013a, b		DSM, Price history and forecast	Low
F		CAC_GAC/MH I-014a, b, c	EnerNOC Utility Solutions	DSM	Low
F		CAC_GAC/MH I-015a, b	EnerNOC Utility Solutions	DSM	Low
F		CAC_GAC/MH I-016	EnerNOC Utility Solutions	DSM	Low
F		CAC_GAC/MH I-017a, b, c		DSM, price elasticity	Low
F		CAC_GAC/MH I-018a, b	2001 Power Resource Plan	DSM comparison	Low
F		CAC_GAC/MH I-019a, b		DSM, adoption rate	Low
F		**CAC_GAC/MH I-020a, b, c, d**	**$3.75/watt in the, $0.65/watt by 2020, 2025 and 2030?**	**Solar**	**High**
F		CAC_GAC/MH I-021a, b, c	EnerNOC Utility Solutions	DSM	Low
F		CAC_GAC/MH I-022a, b, c, d	EnerNOC Utility Solutions	DSM, Commercial miscellaneous	Low
F		CAC_GAC/MH I-023a, b, c, d, e, f		DSM, Energy efficiency	Low
F		CAC_GAC/MH I-024a, b, c, d, e		DSM, Energy efficiency	Low
F		CAC_GAC/MH I-025a, b, c, d		DSM, industrial	Low
F		CAC_GAC/MH I-026		DSM	Low
F		CAC_GAC/MH I-027		Power Smart Plan	Low
F		CAC_GAC/MH I-028a, b, c		DSM	Low
F		CAC_GAC/MH I-029a, b		DSM	Low
F		CAC_GAC/MH I-030a, b		DSM, AMI Smart Grids	Low
F		CAC_GAC/MH I-031a, b, c, e, f, g, h,		DSM	Low
F	Green Action Centre (GAC) Responses	GAC/MH I-001a, b, c	EIA 2013 Annual Energy Outlook, without transmission is $75/MWh, Appendix 7.2	Wind, levelized cost	High
F		GAC/MH I-002	economies of scale	Wind	High
F		GAC/MH I-003a		Wind, Gas, level of estimate	High
F		GAC/MH I-003b		Wind, Gas, escalation	High
F		GAC/MH I-004a, b, c, d	Wind with no escalation going forward, 40% CF	Wind, Capacity Factor	High
F		GAC/MH I-005	GAC/MH I-004a	Wind, levelized cost	Some
F		GAC/MH I-006	basis	Wind, Capacity Factor	High
F		GAC/MH I-007	GAC/MH I-004a		Some
F		GAC/MH I-008	real escalation rate of 0.5%	Real Escalation, Gas	Some

F		GAC/MH I-009	source of these capital cost estimates	Wind, Capital Costs	High
F		GAC/MH I-010a, b	20 years basis, St. Joseph Wind Project has a term of 27 years	Wind, Life Cycle	High
F		GAC/MH I-011a, b	Wind generation would be replaced at current costs	Wind, Life Cycle	High
F		GAC/MH I-012	levelized cost With Transmission	Wind, levelized cost	High
F		GAC/MH I-013	wind integration cost estimates	Wind Integration	High
F		GAC/MH I-014	wind integration cost estimates	Wind Integration	High
F		Manitoba Hydro Wind Integration Sub-Hourly Operational Impacts Assessment	01-Mar-05		Some
F		GAC/MH I-015	NA Order 119/13 the PUB	Wind Integration	Some
F		GAC/MH I-016	NA Order 119/13 the PUB	Wind, Peak Hour	Some
F		GAC/MH I-017	Cold weather shutdown	Wind, Peak Hour	Some
F		GAC/MH I-018a, b, c	REC Premium Marketability, external to the US	Wind, REC	Low
F		GAC/MH I-019a, b, c	transmission development of 943 km, staged, $225 million NPV	Wind/Gas plan, Transmission	Some
F		GAC/MH I-020a, b, c	wind and CCGT development plan or Demand Response programs not evaluated	Wind and CCGT	Some
F		GAC/MH I-021	hourly profiles of wind generation not usec	Wind	Some
F		GAC/MH I-022	GAC/MH I-017	Wind and Temperatures	Some
F		GAC/MH I-023	NA Order 119/13 the PUB	hourly demand	Low
F		GAC/MH I-024	NA Order 119/13 the PUB	hourly demand	Low
F		GAC/MH I-025	hourly flows over Manitoba's intertie:	hourly flows	Low
F		GAC/MH I-026	Hydraulic, Thermal Wind ~ Imports	Monthly Energy Supply	Low
F		GAC/MH I-027a, b, c, d	new generation technologies for hydropower = pumped storage, Keeyask and Conawapa will be capable of supporting wind integration. Pumped storage is not required to integrate wind in M.	Pumped Storage	Low
F		GAC/MH I-028	contracts are tied to the development of major new hydro generating resources	Window of Opportunity	Low
F		GAC/MH I-029 through GAC/MH I-107			
F					
F	Elenchus Research Associate Responses	ERA/MH I-001a through ERA/MH I-045			Low
F	Knight Piésold (KP) Responses	KP/MH I-001b	withdrawn	Estimating Plan	High
F		KP/MH I-001d	withdrawn	Estimating Structure	High
F		KP/MH I-002	withdrawn	Design Lives	High
F		KP/MH I-009	no management reserve for Wuskwatim	Wuskwatim, management reserve	High
F		KP/MH I-010a	increasing demand and shrinking supply	Labour productivity and availability	High
F		KP/MH I-010b	labour turnover can be mitigated through camp	Labour productivity and availability	High
F		KP/MH I-015a	Breakdown	Money Spent to Date	High
F		KP/MH I-016	Breakdown	Estimating methodology	High
F		KP/MH I-017		Cost Estimate Audits	High
F		KP/MH I-018			
F		KP/MH I-019			
F		KP/MH I-020			
F		KP/MH I-021			
F		KP/MH I-022			
F		KP/MH I-023			
F		KP/MH I-024			
F		KP/MH I-025			
F	La Capra (LCA) Responses	LCA/MH I-004 through LCA/MH I-431			
F		LCA 195 attachment 1			
F		LCA 210 attachment 1			
F		LCA 211 attachment 1			
F	Manitoba Industrial Power Users Group (MIPUG) Response	MIPUG/MH I-001 through MIPUG/MH I-042			
F		MIPUG 007 attachment 1			
F	Manitoba Metis Federation (MMF) Responses	MMF/MH I-001 through MMF/MH I-073			
F	MNP Responses	MNP/MH I-001 through MNP/MH I-095			
F	Morrison Park Advisors (MPA)	MPA/MH I-003 through MPA/MH I-017			
F	Potomac (POT) Responses	POT/MH I-001 through POT/MH I-005			
F	Power Engineers. (open new window)	PE/MH I-001 through PE/MH I-014bix			
F	Public Utilities Board Responses	PUB/MH I-001a	actual and weather adjusted sales (GWh)	Residential Basic Customer Sales Table	Low
F		PUB/MH I-001b	weather adjustment broken into heating/cooling	Residential Standard Weather Adjustment	Low
F		PUB/MH I-002	population and metered customer growth/migration	Manitoba Population - 2013 Forecast	Low
F		PUB/MH I-003	population forecast vs. weather adjustments	2011/12 Forecast Compared to Weather Adjusted Actuals	Low

F	PUB/MH I-004a	downward trend of degree day heating fo 10 to 25 yrs	Winnipeg Average Degree Day Heating (DDH)	Low
F	PUB/MH I-004b		DDH vs. MH domestic load graph	Low
F	PUB/MH I-004c	Degree Day Cooling (DDC) added to graph	DDH and DDC vs. MH load grapch	Low
F	PUB/MH I-005a		Power Smart brochures 2005 to 2013	Low
F	PUB/MH I-005b	NA Order 119/13 the PUB	Natural Gas, Electric Heating cost	Low
F	PUB/MH I-005c	NA Order 119/13 the PUB	Natural Gas, Electric Heating cost	Low
F	PUB/MH I-006a	withdrawn	Sector Industry Growth chart	Low
F	PUB/MH I-006b	Industry Load and annual totals for Top Consumers	Industry Load, Top Consumers	Low
F	PUB/MH I-006c	Top Consumer GWh forecasts	Industry sector forecast 2013/14 to 2020/21	Low
F	PUB/MH I-006d	gains/losses of GWh load from closed utility plants	northern smelter and refinery closure, pulp and paper decline	Low
F	PUB/MH I-007a	NA Order 119/13 the PUB	MH load forecast	Low
F	PUB/MH I-007b	general service mass market and top consumers forecast individually; GSMM 38% to 40% of total domestic load	General Service Mass Market / Top Consumers forecasts	Low
F	PUB/MH I-008	NA Order 119/13 the PUB	Total sales table, Total U.S. sales table, Opportunity exports table, Export revenues table	Low
F	PUB/MH I-009	withdrawn	National Energy Board Import and Export Data	Low
F	PUB/MH I-010	NA Order 119/13 the PUB	MH actual and forecast average unit export revenues	Low
F	PUB/MH I-011a	withdrawn	MH System Interconnections and Export Markets	Low
F	PUB/MH I-011b	natural gas prices lower in in spring/summer (US$2.00/MMBtu) and higher in the fall (US$3.50/MMBtu)	Independent Market Monitor, MISO, Price Setting by Unit Type, Capacity Factors by Unit Type	Low
F	PUB/MH I-012a	NA Order 119/13 the PUB	annual exchange rate revenue	Low
F	PUB/MH I-012b	withdrawn	IFF Factors	Low
F	PUB/MH I-013a	withdrawn	ICF natural gas supply forecasts to 2040/41	Low
F	PUB/MH I-013b	ICF's 40-60 year natural gas supply price outlook information and the names of those consultants involved is considered by MH to be Commercially Sensitive Information	ICF, natural gas supply price	Low
F	PUB/MH I-014a	Annual power demand growth expected to be less than Credit Suisse's 'normal' baseline outlook of 1.5%	MISO energy demand forecast	Low
F	PUB/MH I-014b	MH does not tabulate its own projections	MISO region resources; coal, nuclear, wind, natural gas, imports	Low
F	PUB/MH I-015a	withdrawn		Low
F	PUB/MH I-015b	withdrawn	natural gas supply, Henry Hub gas prices	Low
F	PUB/MH I-016a	export limits from MH to US, Ont, and Sask	Export Transfer Limits (MW)	Low
F	PUB/MH I-016b	import limits to MH from US, Ont, and Sask	Import Transfer Limits (MW)	Low
F	**PUB/MH I-016c**	**750 MW interconnection to US; Minneapolis probable since sales insufficient for new line to Ontario**	**Transmission upgrades**	**Some**
F	PUB/MH I-017	withdrawn	Monthly diversity sales / purchases	Low
F	**PUB/MH I-018a**	**MH annual sales to US, merchant sales to Ontario, and other sales to Canada**	**Annual sales, merchant sales**	**Some**
F	**PUB/MH I-018b**	**NA Order 119/13 the PUB**	**Merchant purchases**	**Some**
F	**PUB/MH I-019a**	**2010 GRA/Risk Review Attachment**	**ICF and Consensus Group, export prices**	**Some**
F	PUB/MH I-019b	NA Order 119/13 the PUB	CO2 premiums	Low
F	PUB/MH I-020a	NA Order 119/13 the PUB	Management Control Plan	Low
F	PUB/MH I-020b	NA Order 119/13 the PUB	Management Control Plan	Low
F	PUB/MH I-021	NA Order 119/13 the PUB	Cinergy, Minnesota, price spread	Low
F	PUB/MH I-022a	NA Order 119/13 the PUB	Annual Revenue	Low
F	PUB/MH I-022b	NA Order 119/13 the PUB	Export sales, energy supply	Low
F	PUB/MH I-022c	NA Order 119/13 the PUB	Export sales, energy supply	Low
F	PUB/MH I-023a	NA Order 119/13 the PUB	MH dependable hydraulic energy	Low
F	PUB/MH I-023b	NA Order 119/13 the PUB	Hydraulic generating station output	Low
F	PUB/MH I-023c	NA Order 119/13 the PUB	Hydraulic generation, annual	Low
F	PUB/MH I-023d	NA Order 119/13 the PUB	Thermal, wind, import	Low
F	**PUB/MH I-024**	**Conawapa and Keeyask Recommended Plan and Alternative Scenarios**	**Power Resouce Plan**	**Some**
F	**PUB/MH I-025a**	**Summary of past and future roles**	**Brandon Coal Plant, Brandon SCCT natural gas generator, Selkirk natural gas plant**	**Some**
F	PUB/MH I-025b	NA Order 119/13 the PUB	Regulations on MH coal facilities	Low
F	**PUB/MH I-025c**	**Role of natural gas generating station could play on MH system**	**Combined Cycle Gas Turbine (CCGT), Simple Cycle Gas Turbine (SCGT)**	**High**
F	**PUB/MH I-026a**	**St. Leon and St. Joseph generation for 2011 to 2013**	**Wind energy purchased by MH**	**Some**
F	PUB/MH I-026b	Transmission line development with Minnesota Power increase MH's import and export capabilities	Minnesota Power, wind energy	Low
F	PUB/MH I-027a	DSM to increase dependable energy availability	DSM	Low

F	PUB/MH I-027b	DSM progrm does not provide dispatchability	DSM	Low
F	PUB/MH I-028	Commercially Sensitive Information	MH export commitments	Low
F	PUB/MH I-029a	Commercially Sensitive Information	Drought relief	Low
F	**PUB/MH I-029b**	**Finance expense would increase in the case of a drought since there would be less cash flow due to drought relief provisions**	**Drought relief cost**	**High**
F	PUB/MH I-030	NA Order 119/13 the PUB	Impact analysis - drought relief	Low
F	PUB/MH I-031a	MH anticipates a revenue loss of $7B of export revenue if the Keeyask and/or Conawapa projects do not proceed	Export sales, energy supply	Low
F	PUB/MH I-031b	Commercially Sensitive information	Export sales, energy supply	Low
F	PUB/MH I-031c	Chart showing MH energy output after Keeyask and Conawapa commissioned	Average annual energy output	Low
F	PUB/MH I-031d	Project Operating Statements	Export revenue profile	Low
F	PUB/MH I-031e	Commercially Sensitive Information	Export revenue assumptions	Low
F	PUB/MH I-032a	NA Order 119/13 the PUB	Hydraulic generation / flows by watershed	Low
F	PUB/MH I-032b	NA Order 119/13 the PUB	Lake Winnipeg monthly mean levels	Low
F	PUB/MH I-033	NA Order 119/13 the PUB	Annual fows and revenues	Low
F	**PUB/MH I-034**	**NA Order 119/13 the PUB**	**Annual flows and net revenue**	**Some**
F	PUB/MH I-035a	Attached 2012/13 and 2013/14 General Rate Application (GRA) for 5 and 7 year droughts	Drought impact	Low
F	PUB/MH I-035b	MIPUG GRA for 2013/14	Drought impact	Low
F	PUB/MH I-035c	NA Order 119/13 the PUB	Drought impact	Low
F	PUB/MH I-035d	MH does not maintain a drought financial reserve	Drought reserve	Low
F	PUB/MH I-035e		Drought Mitigation Plan	Low
F	**PUB/MH I-036a**	**Progression of project costs by CEF year**	**CEF12 component costs**	**High**
F	**PUB/MH I-036b**	**NA Order 119/13 the PUB**	**CEF component annual totals**	**Some**
F	**PUB/MH I-037a**	**Potential unit energy costs**	**Dependable energy, average energy**	**High**
F	**PUB/MH I-037b**	**Quotec costs for Wuskwatim, Keeyask, and Conawapa by PUB may be erroneous**	**Project costs**	**Some**
F	**PUB/MH I-038**	**2012/13 and 2013/14 GRA Exhibit #91 explains the cost escalation from CEF03 to CEF12**	**Cost escalation, CEF03, CEF12**	**High**
F	**PUB/MH I-039a**	**NA Order 119/13 the PUB**	**Depreciation**	**Some**
F	**PUB/MH I-039b**	**NA Order 119/13 the PUB**	**Depreciation, Limestone, Long Spruce, Kettle**	**Some**
F	**PUB/MH I-040**	**Attached MH Exhibit #111 from 2012/13 and 2013/14 GRA**	**Cost escalation, CEF12, CEF13**	**High**
F	PUB/MH I-041a	NA Order 119/13 the PUB	Hourly Demands, top 50 peak winter, top 50 peak summer	Low
F	PUB/MH I-041b	NA Order 119/13 the PUB	Peak demands, HVDC, Lower Nelson River Generating Station	Low
F	PUB/MH I-042a	NA Order 119/13 the PUB	Transmission system capabilities, Lower Nelson River Hydraulic Generating Station, Bipole I, II, and III HVDC	Low
F	PUB/MH I-042b	NA Order 119/13 the PUB	Functional usage, Bipole I and II	Low
F	PUB/MH I-042c	NA Order 119/13 the PUB	Functional usage, Bipole I and II, Keeyask	Low
F	PUB/MH I-042d	NA Order 119/13 the PUB	Functional usage, Bipole I, II and III, Keeyask	Low
F	PUB/MH I-042e	NA Order 119/13 the PUB	Functional usage, Bipole I, II and III, Keeyask, Conawapa	Low
F	PUB/MH I-042f	North-South AC transmission line will provide for generation from Keeyask, Long Spruce, Limestone, and Conawapa	Bipole I, II, and II, North-South AC transmission	Low
F	PUB/MH I-043a	NA Order 119/13 the PUB	Electric General Rate Application (GRA)	Low
F	PUB/MH I-043b	Export sales displace natural gas and coal-fried generation	Emission displacement, contract sales, coal, gas	Low
F	PUB/MH I-043c	Estimated emission displacement factor	Peak market sale displacement, coal, gas	Low
F	PUB/MH I-043d	Estimated emission displacement factor	Off-peak weekend sale displacement, coal, gas	Low
F	PUB/MH I-044	Table, 2004 to 2013	Monthly on-peak and off-peak sales	Low
F	PUB/MH I-045	Exports primarily displaced coal GHG emissions by up to 1,000 tons CO2eq/GWh	MISO greenhouse gas (GHG) displacement	Low
F	PUB/MH I-046	MH uses a single GHG displacement factor	GHG displacement, peak and off-peak periods	Low
F	PUB/MH I-047	Figure with Manitoba/Minnesota border	New facilities and transmission lines	Low
F	PUB/MH I-048	Proportion of financing held by MH for new transmission projects and lines	New facilities financed by MH	Low
F	PUB/MH I-049	Description of which facilities and lines are encompassed by the Minnesota-Manitoba Transmission Project	Minnesota-Manitoba Power Project	Low
F	PUB/MH I-050	750 MW, 500 kV line	Great Northern Transmission Line	Low
F	PUB/MH I-051a	Conventional rate-regulated facility, transmission tarifl	MISO OATT, FERC	Low
F	PUB/MH I-051b	Transmission customers request transmission service from the provider	Transmission rights	Low

F	PUB/MH I-052	NA Order 119/13 the PUB	GRA reference documents	Low
F	PUB/MH I-053a	NA Order 119/13 the PUB	Economic forecasts MH06-1, MH07-1, MH08-1, MH09-1, MH10-1, MH10-2, MH11, MH11-2, MH12, MH13	Some
F	PUB/MH I-053b	NA Order 119/13 the PUB	Economic forecasts MH06-1, MH07-1, MH08-1, MH09-1, MH10-1, MH10-2, MH11, MH11-2, MH12, MH13	Some
F	PUB/MH I-054a	NA Order 119/13 the PUB	IFF12, IFF09	Some
F	PUB/MH I-054b	NA Order 119/13 the PUB	IFF09	Some
F	PUB/MH I-054c	Cash flow allocated from electric operations to forecast electrical base capital spending	2012 GRA	Some
F	PUB/MH I-054d	Tables, Proportionate allocation of cash flow from operations to forecat base electrical expenditures	Preferred Development Plan High, Reference and Low Capital Costs	High
F	PUB/MH I-054e	Tables, Proportionate allocation of cash flow from operations to forecat base electrical expenditures	Alternative Development Plans based on High, Reference and Low Capital Costs	Some
F	PUB/MH I-055a	NA Order 119/13 the PUB	2012 GRA	Some
F	PUB/MH I-055b	NA Order 119/13 the PUB	MH09-1, MH12	Some
F	PUB/MH I-055c	IFF13 not available	MH13-1, MH12-1	Low
F	PUB/MH I-056a	MH's export price forecasts are based on several external price forecast consultants	Export price forecast	Low
F	PUB/MH I-056b	Commercially Sensitive Information, filed confidentially with PUB	Supporting calculations, IFF09, IFF10-2, IFF11-2, IFF12-1	Some
F	PUB/MH I-057a	Tables, Revenue Price	2012/13 and 2013/14 GRA	Low
F	PUB/MH I-057b	NA Order 119/13 the PUB	Factors impacting change in export price	Low
F	PUB/MH I-057c	NA Order 126/13 the PUB	Exports, NFAT, IFF12	Low
F	PUB/MH I-058a	NA Order 119/13 the PUB	IFF12	Low
F	PUB/MH I-058b	Table, unit revenues for total export sales	Determination of average export prices, IFF09-1, IFF10, IFF11-2, IFF12	Low
F	PUB/MH I-058c	Tables, base gas prices	2012 GRA	Low
F	PUB/MH I-058d	NA Order 119/13 the PUB	Carbon pricing	Low
F	PUB/MH I-059a	NA Order 119/13 the PUB	Consultants, electricity export price forecasts	Low
F	PUB/MH I-059b	NA Order 119/13 the PUB	2010 and 2012 GRA	Low
F	PUB/MH I-060	NA Order 126/13 the PUB	KPMG, redacted and unredacted reports	Low
F	PUB/MH I-061	Tables/Reports, Capital Expenditure Forecasts	CEF11, IFF12, CEF12	High
F				
F	PUB/MH I-062b	NA Order 119/13 the PUB	Low capital cost, expected capital cost, high capital cost	Some
F	PUB/MH I-062c	NA Order 119/13 the PUB	Dependable energy unit cost	Low
F	PUB/MH I-062d	NA Order 119/13 the PUB	Levelized unit cost	Low
F	PUB/MH I-063a	NA Order 119/13 the PUB, 2011 Annual report	2013 and 2014 GRA	Low
F	PUB/MH I-063b	No changes to JKDA	Joint Keeyask Development Agreements (JKDA)	Low
F	PUB/MH I-064	NA Order 119/13 the PUB	Joint Keeyask Development Agreements (JKDA)	Low
F	PUB/MH I-065	NA Order 119/13 the PUB	Short-term and long-term interest rate forecasts	Some
F	PUB/MH I-066	NA Order 119/13 the PUB, Interest rate tables attached	Interest rate, sensitivity analysis, IFF	Some
F	PUB/MH I-067a	Tables and Reports attached, IFF12	2013 and 2014 GRA, Finance Expense, Risk Table, Net Interchange Revenue, Labour and Benefit Costs, O&A Costs, Staffing Levels, Finance Expense	High
F	PUB/MH I-067b	NA Order 119/13 the PUB	IFF13, Preferred Development Plan	Some
F	PUB/MH I-068a	Tables attached from 2010 GRA	Capital Source	Some
F	PUB/MH I-068b	Tables attached from 2010 GRA	Real Weighted Average Cost and Capital (RWACC)	Some
F	PUB/MH I-068c	Tables	Weighted Average Cost and Capital	Some
F	PUB/MH I-069a	NA Order 119/13 the PUB	Independent Review of Manitoba Hydro Export Power Sales and Associated Risks	Low
F	PUB/MH I-069b	NA Order 119/13 the PUB	Net Present Value, ICF	Low
F	PUB/MH I-069c	NA Order 119/13 the PUB	Net Present Value, ICF	Low
F	PUB/MH I-069d	NA Order 119/13 the PUB	Net Present Value, ICF, NFAT	Low
F	PUB/MH I-070	NA Order 119/13 the PUB	Mr. Judah Rose Direct Testimony, ICF	Low
F	PUB/MH I-071	NA Order 119/13 the PUB	2010 GRA Exhibits	Low
F	PUB/MH I-072	NA Order 119/13 the PUB, additional responses	CAC/MSOS/MH II-100, 2010 GRA	Low
F	PUB/MH I-073a	Tables, Forecasted Payments to the Province	Preferred Development Plan, Capital Costs, Energy Prices, Interest Rates	Some
F	PUB/MH I-073b	Tables, Forecasted Payments to the Province	Preferred Development Plan, Capital Costs, Energy Prices, Interest Rates	Some
F	PUB/MH I-074a	NA Order 119/13 the PUB, Tables attached	2012/13 and 2013/14 GRA, Projected Operating Statement, Projected Cash Flow Statement, Projected Balance Sheet	Some
F	PUB/MH I-074b	NA Order 119/13 the PUB, 2012/13 Wuskawatim Year in Review :	IFF13, Annual (Wuskawatim Power Limited Partnership) WPLP Report	Some

F		PUB/MH I-075a	NA Order 119/13 the PUB, Tables attached	Estimated Impacts of Wuskawatim on Net Income, Integrated Financial Forecast	Some
F		PUB/MH I-075b	NA Order 119/13 the PUB	Annual Impact on Net Income from Keeyask and Conawapa	Some
F		PUB/MH I-076	NA Order 119/13 the PUB	2012 GRA, Exhibit #108	Low
F		PUB/MH I-077a	NA Order 119/13 the PUB, Tables attached	2012 GRA, WPLP revenue calculation process, Projected Operating Statement, Projected Cash Flow Statement, Projected Balance Sheet, OM&A Costs, Finance Expense Forecast, Interest Rates, Revenue, Water Rentals	Some
F		PUB/MH I-077b	NA Order 119/13 the PUB, Report attached	IFF12-1 for WPLP	Low
F		PUB/MH I-077c	Revenue attribution for on-peak and off-peak hours	Keeyask Joint Development Agreement	Low
F		PUB/MH I-077d	Commercially Sensitive Information, filed confidentially with PUB	Keeyask Joint Development Agreement, detailed revenue calculations	Some
F		PUB/MH I-078a	NA Order 119/13 the PUB, debt ratio and projected partners capital tables attached	2012/13 and 2013/14 GRA, Exhibit #114	Some
F		PUB/MH I-078b	Tables, Debt Ratio and Protected Partners Capital Account	Keeyask Hydro Limited Partnership (KHLP), debt/equity ratio, Preferred Development Plan	Some
F		PUB/MH I-079a	NA Order 119/13 the PUB	2010 GRA IRR/CEC Submission	Low
F		PUB/MH I-079b	NA Order 119/13 the PUB	Gull/Keeyask, Conawapa, IRR estimates	High
F		PUB/MH I-079c	Table, IRR for 15 development plans	IRR analysis, Preferred Development Scenarios, Alternative Development Scenarios	High
F		PUB/MH I-080a	MH Exhibit #112 attached provides impact deferral estimate of Wuskwatim, Keeyask and Conawapa	2012 GRA, Exhibit #112, IFF09 to IFF12	Some
F		PUB/MH I-080b	Table, 1- to 3-year deferrral rates for Conawapa and Keeyasl for Low Reference and High Capital/Financing Costs	Cost of deferral, Conawapa, Keeyask	Some
F		PUB/MH I-081a	Tables, Projected Finance Expenses	Net Finance Expense	High
F		PUB/MH I-081b	Tables, Projected Finance Expenses	Net Finance Expense, High/Low Construction Costs, High/Low Interest Rates	High
F		PUB/MH I-082a	Tables	General Consumer Revenue	Low
F		PUB/MH I-082b	See PUB/MH I-054d	Preferred Development Plan, 2010 GRA Internally Generated Funds	High
F		PUB/MH I-083	Report attached	MH 62nd Annual Report	Low
F		PUB/MH I-084	Low water levels, cost overruns, construction delays	Unforeseen circumstance according to MH	Low
F		through to PUB/MH I-294			Low
F	Supplemental Round 1 Cover Letter dated November 15, 2013				
F	November 15, 2013 Responses				
F	Supplemental Round 1 Cover Letter dated November 22, 2013				
F	November 22, 2013 Responses				
F	Supplemental Round 1 Cover Letter dated November 15, 2013				
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F	November 15, 2013 Responses				
F	Supplemental Round 1 Cover Letter dated November 15, 2013				
F	November 15, 2013 Responses				

Information Requests - Round 2

F	Round 2 cover letter dated December 13, 2013.				Low
F	Consumers Association of Canada (CAC) Responses.	CAC/MH II-001		Capital Cost, P50 and Point Estimate Definition	High
F		CAC/MH II-002		Executive Committee Recommendation	Some
F		CAC/MH II-004a		Keeyask Cost reconciliation	High
F		CAC/MH II-013a, b		Transmission Reliability	Low
F		CAC/MH II-021a, b		Export Contract	Low
F		CAC/MH II-023		Export Contract	Low
F		CAC/MH II-026a, b		Load Forcast	Low
F		CAC/MH II-027		Load Forcast	Low
F		CAC/MH II-030a		Great Northern Transmission Line	Low
F		CAC/MH II-030b		Export Markets	Low

F		**CAC/MH II-044**	**6% real as the social opportunity cost of capital**	**Discount Rate**	**Some**
F		CAC/MH II-045	Burgess and Zerbe study	Cost Benefit Analysis	Low
F		CAC/MH II-046a, b	Marvin Shaffer	Wuskwatim Project	Low
F		CAC/MH II-047a, b		Project Benefits	Low
F		CAC/MH II-048	income classes and urban versus rural residents		Low
F		CAC/MH II-049a, b		Manitoba Economy	Low
F		CAC/MH II-051a, b, c		net present value of the rate impact effects	Low
F		CAC/MH II-052a, b		social opportunity cost of capital	Low
F		**CAC/MH II-052 c**		**appropriate discount rat**	**Some**
F		CAC/MH II-053		monetized net benefits (costs) on a PV	Low
F		**CAC/MH II-069 a**		**capital tax and debt guarantee fee**	**Some**
F		**CAC/MH II-069 b**		**inconsistencies or double counting**	**Some**
F		CAC/MH II-073a	Scenarios assumed normal weather		Low
F		CAC/MH II-074c	MP is investing in 51% of the cost within Minnesota.		Low
F		CAC/MH II-075a		firm export contracts	Low
F		CAC/MH II-086		Tariff Coordination Agreements	Low
F		CAC/MH II-087		Minnesota Renewable Portfolio Standard	Low
F		CAC/MH II-088		no MISO funding on TL	Low
F		CAC/MH II-090a, b	In Manitoba, MH will own all the interconnection facilitie:	ownership in Manitoba	Low
F		CAC/MH II-091		right to use and ownership	Low
F		CAC/MH II-092a		right to use and ownership	Low
F		CAC/MH II-096a, b	weighted average opportunity cost	Burgess and Zerbe study	Low
F		**CAC/MH II-100**	**PUB/MH II-381b**	**3% premium over the cost of debt).**	**Some**
F		CAC/MH II-106		losses related to export	Low
F		CAC/MH II-107		CSI, Critical Energy Infrastructure	Low
F		CAC/MH II-110a		capital tax, water rentals	Low
F		CAC/MH II-114a, b, c	6% was the discount rate used to establish the 2014 present value	discount rate	Low
F		CAC/MH II-115a, b	6% was the discount rate all plans	discount rate, GHG external costs	Low
F		CAC/MH II-116a, b		bill savings from DSM, Multiple Account Analysis	Low
F		CAC/MH II-119	contracts set out in Appendix 9.3, Table 1.9	energy from hydro facilities	Low
F		CAC/MH II-124		number of residential customers	Low
F		CAC/MH II-125		number of residential customers	Low
F		CAC/MH II-127		Transmission Expansion Plan's "Combined Policy"	Low
F		**CAC/MH II-128**		**Natural Gas volatility**	**Some**
F		CAC/MH II-129		Export Markets; 1 Price Forecasts	Low
F		CAC/MH II-131		Coal Energy Imports	Low
F		CAC/MH II-140		Dr. Shaffer	Low
F	Green Action Centre/Consumers Association of Canada (GAC CAC) Responses	GAC_CAC/MH II-004		DSM, price elasticities	Low
F		GAC_CAC/MH II-005	electronic Atachments 1 through 6	DSM, Appendix B	Low
F		GAC_CAC/MH II-006b		DSM	Low
F		GAC_CAC/MH II-007a, b	September 2008 Navigant Consulting	DSM	Low
F		GAC_CAC/MH II-009a, b, c, d		DSM	Low
F		GAC_CAC/MH II-010a, b, c, d		DSM	Low
F		GAC_CAC/MH II-011a, b, c		heat pump system	Low
F		GAC_CAC/MH II-012		real discount rate used	Low
F	**Green Action Centre (GAC) Responses**	**GAC/MH II-003b**	**LCA/MH I-308**	**Wind Levelized Cost of Energy**	**Some**
F	**Knight Piésold (KP) Responses**	**KP/MH II-026a**	**P50, P80, P90, P95**	**Contingency**	**High**
F		**KP/MH II-026c**	**Capital Cost High, Reference, and Low**	**Scenario Development**	**High**
F	**La Capra (LCA) Responses**	**LCA/MH II-461**	**IRs from Previous Hearings that Address Operations, Quantification of Drought Risk**	**Reservoir Operation, Drought Impacts**	**Some**
F		LCA/MH II-462		Drought Impact, MISO	Low
F		LCA/MH II-463		Drought Impact, MISO	Low
F		LCA/MH II-467		Reservoir Operation	Low
F		LCA/MH II-468a, b, c, d		Reservoir Operation; opportunity sales	Low
F		LCA/MH II-477	no delivered natural gas price forecasts	Natural Gas Price	Low
F		LCA/MH II-484		Export Contracts; Export Market Policies	Low
F		LCA/MH II-487		Export Contracts; Export Market Policies	Low
F		LCA/MH II-488		Export Contracts; Export Market Policies	Low
F		LCA/MH II-494 to 502	Integrated Transmission Plan for K. and C. Generation SPD	Transmission Economics	Low
F		LCA/MH II-506a, b		MISO; Opportunity Exports	Low
F		LCA/MH II-507a, b, c		MISO; Opportunity Exports	Low

F	**Manitoba Industrial Power Users Group (MIPUG) Responses**	**MIPUG/MH II-006a**	**a reduction in debt guarantee fee would lower the discount rate**	**debt guarantee**	**Some**
F		MIPUG/MH II-008	DSM as percentage of total load growth	DSM	Low
F		MIPUG/MH II-014a, b		DSM, heating choice	Low
F		MIPUG/MH II-019b		off-peak import capability	Low
F		MIPUG/MH II-023a		U.S. Interconnection	Low
F	**Manitoba Metis Federation (MMF) Responses**	**MMF/MH II-003**	**single line diagrams**	**Economic Risk, single line diagrams**	**Some**
F		MMF/MH II-004a, b	Bipole III Converter Stations October 2017 in Serivce Date	Economic Risk, Riel and Keewatinoow Converter Stations	Low
F		MMF/MH II-005b	upgrading PR290	Economic Risk	Low
F		MMF/MH II-006	North-South Transmission System Upgrade Project	Economic Risk	Low
F		MMF/MH II-007b, c, d		Economic Risk	Low
F		MMF/MH II-008a	NERC transmission planning standards	Economic Risk	Low
F		MMF/MH II-016a, b, c, d, e	HVDC and AC, N-1, N-1-1 and N-2 transmission contingencies	Economic Risk	Low
F		MMF/MH II-017a	MMF/MH II-016e	HVDC, Economic Risk	Low
F		MMF/MH II-018a, b, c	Bipole I and II has a rating of 3854 MW	HVDC, Economic Risk	Low
F		MMF/MH II-019a, c, d, e, f, h	HVdc system Kettle, Long Spruce and Limestone under normal operating conditions	HVDC, Economic Risk	Low
F		MMF/MH II-020a, b, c, d, e, f, g		HVDC, Economic Risk	Low
F		MMF/MH II-021b	Transmission Loading Relief (TLR) Procedures, Emergency Operations - Real Time Capacity and Energy Emergency Procedures, MISO Congestion Management Procedure, Transmission Loading Relief	HVDC, Economic Risk	Low
F		MMF/MH II-022d		Economic Risk	Low
F		MMF/MH II-023		Economic Risk, RPS requirements	Low
F		MMF/MH II-024a, b, c	transmission costs	Economic Risk, RPS requirements	Low
F		MMF/MH II-026a	LCA/MH I-308	Economic Risk, Levelized Cost	Low
F		MMF/MH II-030	water rental, capital tax transfer and provincial guarantee fees are a cost	Economic Risk	Low
F		MMF/MH II-032		Economic Risk	Low
F		MMF/MH II-033	Present Worth Calculation-MMF-033 expected unserved energy costs	Economic Risk	Low
F		MMF/MH II-034a	map of new transmission lines, MMF/MH II-034a Attachment	Environmental impacts	Low
F		MMF/MH II-036a, c	Chapter 15 Figure 15.3 and Figure 15.4, camps versus communities	Socio-economic impacts: employment	Low
F		**MMF/MH II-037a, b**	**work by Northern and Aboriginal businesses other than the KCNs**	**Socio-economic impacts: business opportunities**	**Some**
F		MMF/MH II-038a, c, d	CAC/MH I-231a	Socio-economic impacts: infrastructure and services	Low
F		MMF/MH II-039	Cumulative Effects Assessment Summary	Socio-economic impacts: personal, family and community life	Low
F		MMF/MH II-041	MMF/MH I-053a, significance definition	Macro-environmental	Low
F		MMF/MH II-042b, c		Economic Risk, real GDP	Low
F		**MMF/MH II-043a**	**resident definition**	**Socio-economic impacts: employment**	**Some**
F		**MMF/MH II-043b**	**2001 person years Manitobans and 858 non-Manitobans**	**Waskwatim**	**Some**
F	Morrison Park Advisors (MPA)	MPA/MH II-018	Export Sales Revenue	Chapter 5, Figure 5.3	Low
F		MPA/MH II-019a, b	Export Sales TWh, gross export sales	Chapter 5, Figure 5.4	Low
F		MPA/MH II-020	net export sales	Chapter 5, Figure 5.4	Low
F		MPA/MH II-021	Historical Water Supply	Chapter 5, Figure 5.8	Low
F	**Power Engineers**	**PE/MH II-015**	**lattice structure weights**	**Transmission Line**	**Some**
F		**PE/MH II-016a, b, c, d, e, f, g, h, I, j**	**$300,000 per km estimate**	**Transmission Line**	**Some**
F		PE/MH II-017a, b, c		Transmission Reliability	Low
F	Public Utilities Board (PUB) Responses	PUB/MH II-300	Export Price Forecast CSI	Capacity Pricing	Low
F		PUB/MH II-306	CSI	Carbon Pricing	Low
F		PUB/MH II-307a, b	MISO generation mix "assumptions"	MISO	Low
F		PUB/MH II-308a, b, c, d, e	CSI	Export Price Forecasts	Low
F		PUB/MH II-310a, b	CSI	Capacity Price	Low
F		PUB/MH II-312b, c, d	CSI	2012 Export Price Forecast	Low
F		PUB/MH II-313a, b	CSI	2013 Export Price Forecast	Low
F		PUB/MH II-316d, f	CSI	Export Contracts	Low
F		PUB/MH II-317a, b, c, e, g	CSI	Export Contracts	Low
F		PUB/MH II-318b, f, g	CSI	Export Contracts	Low
F		PUB/MH II-319a, b, c, d, f	CSI	Export Contracts	Low
F		PUB/MH II-321b	CSI	Export Contracts	Low
F		PUB/MH II-323a, b, c, d	CSI	Export Contracts	Low

F	PUB/MH II-324a, b, c, d	CSI	Export Contracts	Low
F	PUB/MH II-325a, b, c, d, e, f, g, h	CSI	Export Contracts	Low
F	PUB/MH II-327b	2012/13 Power Resource Plan, CSI	Transmission	Low
F	PUB/MH II-331b, c	MP Application to Minnesota PUC, CSI	Transmission	Low
F	PUB/MH II-332b, d, e, f, g, h, i, j, k	CSI	Transmission	Low
F	PUB/MH II-334a	CSI	Export Contracts	Low
F	PUB/MH II-336	CSI	Export Contracts	Low
F	PUB/MH II-337a, c, d	CSI	Access (transmission)	Low
F	PUB/MH II-338	CSI	Access (transmission)	Low
F	PUB/MH II-339a, b	CSI	Access (transmission)	Low
F	PUB/MH II-347	CSI	Export Pricing	Low
F	PUB/MH II-363	distribution loss weather adjustments	Load Forecast	Low
F	PUB/MH II-364a, b	Historical Degree Day Heating	Load Forecast	Low
F	PUB/MH II-365	2012 Load Forecast	Load Forecast	Low
F	PUB/MH II-366a, b, c	Mass Market and Residential Load	Load Forecast	Low
F	PUB/MH II-367	2012 GRA PUB	Export Revenue	Low
F	**PUB/MH II-374a**	**determination of the escalation management reserves**	**Capital Expenditures**	**High**
F	**PUB/MH II-374c**	**consulting fees paid by consultant for the Keeyask and Conawapa projects, PUB-MH II-446b, consistent with APEGM**	**Capital Expenditures**	**High**
F	PUB/MH II-379	No Electricity Export Price Forecast report for 2009	Electricity Prices	Low
F	PUB/MH II-381a, b	300 basis point to the Long Term Debt Rate	WACC	Low
F	PUB/MH II-392a, b	Orders 119/13 and 126/13, percentage of savings	DSM	Low
F	PUB/MH II-393a	Orders 119/13 and 126/13	DSM	Low
F	**PUB/MH II-395**	**CSI**	**Purchased Wind Energy**	**Some**
F	PUB/MH II-403a	CSI	U.S. Off-Peak Sales	Low
F	**PUB/MH II-410a**	**project construction start changes, not answered**	**Keeyask G.S. Startup**	**Some**
F	**PUB/MH II-421a**	**CSI**	**Capital Construction Costs**	**Some**
F	**PUB/MH II-423a, b, c**	**Wuskwatim and Keeyask Training Consortium Annual Report none for 2012, Hydro Northern Training and Employment Initiative, outcomes have not been captured**	**Macro-Economic, Aboriginal employment by community for Keeyask**	**Some**
F	PUB/MH II-427a, b		Ratepayer Impacts	Low
F	PUB/MH II-436d	capital expenditures in Manitoba goods or services	Socio-Economic	Low
F	PUB/MH II-445a	First Nations agreements for Conawapa	First Nations	Low
F	**PUB/MH II-445b**	**financial details of all agreements**	**First Nations**	**Some**
F	PUB/MH II-445c	Conawapa differs from Keeyask	First Nations	Low
F	**PUB/MH II-447**	**why net capital expenditures for Keeyask and Conawapa exclude the labour reserve and escalation of labour reserve**	**Capital Costs**	**High**
F	PUB/MH II-450d	not 67% of the capital	Transmission	Low
F	PUB/MH II-452	summarize the financial terms of the adverse effects agreements Payment Schedule	First Nations	Low
F	PUB/MH II-453	protection from adverse effects, PUB/MH I-064	First Nations	Low
F	PUB/MH II-455		Bond Yields	Low
F	PUB/MH II-456	CSI	Economic Evaluation	Low
F	PUB/MH II-457a, b	new loads	Load Forecasts/Top Consumers	Low
F	PUB/MH II-463a, b	PUB/MH I-235a	Export Price Forecasts	Low
F	PUB/MH II-465a, b	industry load growth	Load Forecast	Low
F	PUB/MH II-466b, d		MISO Export Price Forecasts/ CO2 Adders	Low
F	PUB/MH II-469a		MISO Renewables	Low
F	PUB/MH II-476		Typical Space & Water Heater Costs	Low
F	PUB/MH II-477		2012 MH GRA Exhibit #43	Low
F	PUB/MH II-478a, b, c, d, e, f		Industry Sector Load Growth History	Low
F	PUB/MH II-479a, b, c, d		Top Consumers	Low
F	PUB/MH II-480a, b		Industrial Load Growth Since 2004/08	Low
F	PUB/MH II-490a, b, c	sudden loss of the existing Dorsey-Forbes 500 kV line, constrain exports from Manitoba	Access (Transmission)	Low
F	PUB/MH II-491		Minnesota-Manitoba Transmission Line	Low
F	PUB/MH II-492a, b, c, d		Transmission Reliability	Low
F	PUB/MH II-497a, b		Electric Heating Load	Low
F	PUB/MH II-499a	short-term opportunities for Northern and aboriginal workers on Manitoba – Minnesota and North – South	First Nations	Low
F	**PUB/MH II-499b**	**$200 million in Northern First Nations from KIP**	**First Nations**	**Some**
F	**PUB/MH II-499c**	**Conawapa G.S. Project ownership**	**First Nations**	**Some**

F		PUB/MH II-499d,e, f, g, h, i, j	income, training , employment and business opportunities, Valued Environmental Component, fish, risk communication plan	First Nations	Low
F	**Supplemental round 2 cover letter dated December 20**			Cover	Low
F	**Supplemental IR responses**	CAC/MH II-023	on-peak and off-peak price forecasts	Export Markets	Low
F		CAC/MH II-049b	CAC/MH I-156a	Manitoba Economy	Low
F		CAC/MH II-100	interest rate associated with equity used in the RWACC, PUB/MH II-381b	RWACC	Low
F		CAC/MH II-106	losses described in PUB/MH I-187	Losses	Low
F		**CAC/MH II-128**	**high volatility**	**Natural Gas**	**Some**
F		LCA/MH II-468a, b, c, d	CSI	Reservoir Operation	Low
F		LCA/MH II-484	2012 08 Wholesale Export Policy	Export Contracts	Low
F		LCA/MH II-487	CSI	Export Contracts	Low
F		LCA/MH II-494	CSI	Transmission Economics	Low
F		LCA/MH II-495	CSI	Transmission Economics	Low
F		LCA/MH II-500	CSI	Transmission Economics	Low
F		MIPUG/MH II-019b	imports of energy from Ontario should not be considered	off-peak import capability	Low
F		MMF/MH II-004b	capability of the Bipole III	Economic Risk	Low
F		Repeats.... Of IR Responses			Low
F	**Supplemental round 2 cover letter dated December 24**			Cover	Low
F	**Supplemental IR responses**	Duplicates			Low
F		GAC_CAC/MH II-003	early retirement measures	DSM	Low
F		MMF/MH II-015	reliability of Manitoba Hydro's 10-year capital plan	Economic Risk	Low
				Cover	Low
F	Supplemental round 2 cover letter dated January 8, 2014				
F	Supplemental IR responses	CAC/MH II-024	US GDP Deflator inflation rates	Export Markets, inflation	Low
F		CAC/MH II-050a, b, c	NA	appropriateness of the analytical approaches	Low
F		CAC/MH II-057		S-Curves	Low
F		CAC/MH II-058		S-Curves	Low
F		CAC/MH II-067a	MIPUG/MH II-4a		Low
F		CAC/MH II-073b	Appendix D	Load Forecast	Low
F		CAC/MH II-108b	does include provincial coal taxes and carbon charges on gas generation	Carbon Pricing	Low
F		CAC/MH II-116c		DSM	Low
F		CAC/MH II-136		Load Forecast	Low
F		CAC/MH II-137		Load Forecast	Low
F		CAC/MH II-139		Aboriginal Traditional Knowledge	Low
F		**GAC/MH II-001**	**CSI**	**Gas Generation Capital Cost**	**Some**
F		GAC_CAC/MH II-002	EnerNOC Utility Solutions	DSM	Low
F		GAC_CAC/MH II-006a	RIM in conjunction with the Levelized Utility Cost (LUC)	RIM test	Low
F		GAC_CAC/MH II-010e	outsourcing DSM	DSM	Low
F		**KP/MH II-026b**	**Parametric and Expected Value Modeling method (RP's 40R-08, 42R-08, 44R-08), no AACE standard that outlines the "correct" level of contingency to include**	**Contingency**	**High**
F		LCA/MH II-485		Wholesale Export	Low
F		LCA/MH II-504	(+/- 50%)?	Transmission Economics	Low
F		LCA/MH II-505		Transmission Economics	Low
F		MIPUG/MH II-004a		the regret approach	Low
F		MIPUG/MH II-017			Low
F		MMF/MH II-022b		Economic Risk	Low
F		MMF/MH II-042a		Economic Risk	Low
F		PUB/MH II-295a		Export Prices	Low
F		PUB/MH II-296a, b, c, d, e	CSI	Export Prices	Low
F		PUB/MH II-302a	CSI	Carbon Pricing	Low
F		PUB/MH II-305a	CSI	Average Export Prices	Low
F		PUB/MH II-312a	CSI	Export Prices	Low
F		PUB/MH II-317i	CSI	Export Contracts	Low
F		PUB/MH II-340	CSI	Export Contracts	Low
F		PUB/MH II-345a, b, c	CSI	Export Contracts	Low
F		PUB/MH II-349	CSI	Aggregated Export Revenues	Low
F		etc...			Low

General Rate Applications				
F	**2010/11 & 2011/12 GRA**			
F	2010/11 & 2011/12 GRA - MH Exhibit #154 - Tab 9	MH 20 Year Financial Outlook	Capital Expenditures	Low
F	**2010/11 & 2011/12 GRA - PUB (MH) I-202 - Tab 8**	**Post Major Development Construction Costs**	**Capital Expenditures**	**High**
F	2010/11 & 2011/12 GRA - PUB (MH) I-54 - Tab 4	Wuskwatim Construction Detail	Capital Expenditures	Low
F	**2010/11 & 2011/12 GRA - PUB (MH) I-65**	**Wuskwatim Cost Progression**	**Capital Expenditures**	**High**
F	**2010/11 & 2011/12 GRA - PUB (MH) II-35 (c) - Tab 7**	**Interest Expense Allocation to Construction Example**	**Capital Expenditures**	**High**
F	**2010/11 & 2011/12 GRA - Appendix 25 - Tab 7 - PUB/MH I 107 - Tab 7**	**Dunsky Report 2009 Market Scan**	**DSM & Energy Efficiency**	**High**
F	2010/11 & 2011/12 GRA - PUB/MH I-106 - Tab 1	Power Smart Plan 2009/10	DSM & Energy Efficiency	Low
F	2010/11 & 2011/12 GRA - PUB (MH) II- 7 (a) - Tab 4 - PUB/MH I-75 - Tab 4	Joint Keeyask Development Agreement	Economic Evaluation	Low
F	**2010/11 & 2011/12 GRA - PUB/MH I-79 - Tab 11**	**Discount rate on major capital projects**	**Economic Evaluation**	**High**
F	2010/11 & 2011/12 GRA - PUB/MH I-80&82 - Tab b)	ICF NPV Analysis	Economic Evaluation	Low
F	2010/11 & 2011/12 GRA - PUB/MH I-80&82 - Tab c)	ICF NPV Analysis	Economic Evaluation	Low
F	2010/11 & 2011/12 GRA - PUB/MH I-80&82 - Tab d)	ICF NPV Analysis	Economic Evaluation	Low
F	2010/11 & 2011/12 GRA - PUB/MH I-80&82 - Tab e)	ICF NPV Analysis	Economic Evaluation	Low
F	2010/11 & 2011/12 GRA - PUB/MH I-81 - Tab a)	ICF Report	Economic Evaluation	Low
F	2010/11 & 2011/12 GRA - PUB/MH I-83 - Tab f)	ICF Report Risks	Economic Evaluation	Low
F	2010/11 & 2011/12 GRA - PUB/MH I-85 - Tab a)	WPLP IFF07	Economic Evaluation	Low
F	2010/11 & 2011/12 GRA - PUB/MH I-90 - Tab g)	IRR Wuskwatim	Economic Evaluation	Low
F	2010/11 & 2011/12 GRA - PUB/MH I-91 - Tab 15	Cost of Deferring Major New Generation	Economic Evaluation	Low
F	2010/11 & 2011/12 GRA - PUB/MH I-93 - Tab 18	Internally Generated Funds	Economic Evaluation	Low
F	2010/11 & 2011/12 GRA - PUB/MH I-4 - Tab 4	CAC/MSOS-16	Load Growth	Low
F	2010/11 & 2011/12 GRA - PUB/MH I-111 - Tab 3	GHG Displacement Estimates	Macro – Environmental	Low
F	2010/11 & 2011/12 GRA - PUB/MH I-60 - Tab 2	US Opportunity Sales 2004 and 2005	Macro – Environmental	Low
F	2010/11 & 2011/12 GRA - PUB/MH I-14 - Tab 3	Unit Export Revenue Assumptions	MISO	Low
F	2010/11 & 2011/12 GRA - PUB/MH I-16 - Tab 5	Export Revenue & Exchange Rate 2010	MISO	Low
F	2010/11 & 2011/12 GRA - PUB/MH I-17 - Tab 6	NG Supply Forecast	MISO	Low
F	2010/11 & 2011/12 GRA - PUB/MH I-18 - Tab 7	PUB (MH) I-18(a)	MISO	Low
F	2010/11 & 2011/12 GRA - PUB/MH I-21 - Tab 9	MISO Diversity Sales and Purchases	MISO	Low
F	2010/11 & 2011/12 GRA - PUB/MH I-22 - Tab 10	MISO & Other Market Activities	MISO	Low
F	2010/11 & 2011/12 GRA - PUB/MH I-23 - Tab 11	MISO Market	MISO	Low
F	2010/11 & 2011/12 GRA - PUB/MH I-24 - Tab 12	MISO Exports	MISO	Low
F	2010/11 & 2011/12 GRA - PUB/MH I-25 - Tab 13	On-Peak Price Spreads Cinergy and Minnesota Hubs	MISO	Low
F	2010/11 & 2011/12 GRA - PUB/MH I-28 -38 - Tab 3	Power Resource Plan 2008/09	Power Resource Plan	Low
F	2010/11 & 2011/12 GRA - PUB/MH I-39 - Tab 11	Monthly Hydraulic Generation & River Flows	Power Resource Plan	Low
F	2010/11 & 2011/12 GRA - PUB/MH I-40 - Tab 12	Annual System Flows	Power Resource Plan	Low
F	2010/11 & 2011/12 GRA - PUB/MH I-41 - Tab 13	Total Energy In Reservoir Storage	Power Resource Plan	Low
F	2010/11 & 2011/12 GRA - PUB (MH) I-11 (e) - Tab 4 - PUB/MH I-104 - Tab 4	First Nations Agreements	Socio - Economic	Low
F	2010/11 & 2011/12 GRA - PUB (MH) II- 7 (a) - Tab 2 - PUB/MH I-104 - Tab 2	PUB (MH) II- 7 (a) Refer to Table 2	Socio - Economic	Low
F	2010/11 & 2011/12 GRA - PUB (MH) II-91 (a) - Tab 2 - PUB/MH I-56 - Tab 2	HVDC System Usage	Transmission Issues	Low
F	**2012/13 & 2013/14 GRA - CAC (MH) II-47 (b) - Tab 6**	**CPJ Description**	**Capital Expenditures**	**Some**
F	**2012/13 & 2013/14 GRA - Exhibit #10 - Tab 12**	**Capital Expenditure Forecast CEF12**	**Capital Expenditures**	**Some**
F	**2012/13 & 2013/14 GRA - MH Exhibit #106 - Tab 4**	**Wuskwatim Component Costs**	**Capital Expenditures**	**High**
F	**2012/13 & 2013/14 GRA - MH Exhibit #111 - Tab 5**	**Keeyask & Conawapa Cost Escalation**	**Capital Expenditures**	**High**
F	**2012/13 & 2013/14 GRA - MH Exhibit #68 - Tab 10**	**Capital Cost Breakdown - Depreciation Study for Wuskwatim**	**Capital Expenditures**	**High**
F	**2012/13 & 2013/14 GRA - MH Exhibit #91 - Tab 3**	**Wuskwatim Cost Escalation**	**Capital Expenditures**	**High**
F	**2012/13 & 2013/14 GRA - PUB (MH) I-93 (a) - Tab 1**	**Progression of Major G&T Project Costs**	**Capital Expenditures**	**High**
F	**2012/13 & 2013/14 GRA - PUB (MH) II-68 - Tab 6**	**CPJ Forms**	**Capital Expenditures**	**Some**
F	**2012/13 & 2013/14 GRA - Tab 6 - Appendix 6.1 - Tab 11**	**Capital Expenditure Forecast CEF11**	**Capital Expenditures**	**Some**
F	**2012/13 & 2013/14 GRA -PUB (MH) I-13 (a) - Tab 2**	**New Generation Incremental Energy Costs**	**Capital Expenditures**	**Some**
F	2012/13 & 2013/14 GRA - - Tab 6 - PUB/MH I-107 - Tab 6	Dunsky MH Testimony (2012-11-15)	DSM & Energy Efficiency	Low
F	2012/13 & 2013/14 GRA - - Tab 8 - PUB/MH I-108 - Tab 8	Dunsky Six Undertakings	DSM & Energy Efficiency	Low

F	2012/13 & 2013/14 GRA - Appendix 4.2 - Tab 3 - - Tab 3	Power Smart Plan 2013 - 2016	DSM & Energy Efficiency	Low
F	2012/13 & 2013/14 GRA - CAC (MH) II-27 (b) - Tab 9 - PUB/MH I-109 - Tab 9	Avoided Costs Estimates	DSM & Energy Efficiency	Low
F	2012/13 & 2013/14 GRA - CAC-GAC (MH) I-4 - Tab 9 - PUB/MH I-109 - Tab 9	Avoided Cost Estimates	DSM & Energy Efficiency	Low
F	2012/13 & 2013/14 GRA - Exhibit #85 - Undertaking #63 - Tab 10 - PUB/MH I-110 - Tab 10	Breakdown of Marginal Benefits	DSM & Energy Efficiency	Low
F	2012/13 & 2013/14 GRA - Exhibit MH-132 UT#125 - Tab 12 - PUB/MH I-111 - Tab 12	GHG Displacement Estimates	DSM & Energy Efficiency	Low
F	2012/13 & 2013/14 GRA - GAC (MH) II-23 (c) - Tab 11 - - Tab 11	Marginal Cost Estimates	DSM & Energy Efficiency	Low
F	2012/13 & 2013/14 GRA - GAC (MH) II-23 (d) - Tab 11 - - Tab 11	Marginal Cost Estimates	DSM & Energy Efficiency	Low
F	2012/13 & 2013/14 GRA - PUB (CAC& GAC) 16 - Tab 13 - PUB/MH I-112 - Tab 13	DSM Screening Tests	DSM & Energy Efficiency	Low
F	2012/13 & 2013/14 GRA - PUB (CAC& GAC) 18 - Tab 8 - PUB/MH I-108 - Tab 8	DSM Role in Generation Deferral	DSM & Energy Efficiency	Low
F	2012/13 & 2013/14 GRA - PUB (MH) I-107 (a) (b) & (c) - Tab 9 - PUB/MH I-109 - Tab 9	DSM Marginal Cost Used for Screening DSM	DSM & Energy Efficiency	Low
F	2012/13 & 2013/14 GRA - Tab 7 - Appendix 7.1- Power Smart Resource Plan - Tab 2 - PUB/MH I-106 - Tab 2	Power Smart Plan 2011	DSM & Energy Efficiency	Low
F	2012/13 & 2013/14 GRA - Tab 7 - Appendix 7.2 - Tab 4 - PUB/MH I-106 - Tab 4	Annual Power Smart Review	DSM & Energy Efficiency	Low
F	2012/13 & 2013/14 GRA - Tab 7 - Tab 5 - - Tab 5	Demand Side Management	DSM & Energy Efficiency	Low
F	2012/13 & 2013/14 GRA - Appendix 1.3 - Tab 1 - - Tab 1	2012 Annual Report	Economic Evaluation	Low
F	2012/13 & 2013/14 GRA - Appendix 4.1 - Tab 3 - - Tab 3	Economic Outlook 2012	Economic Evaluation	Low
F	2012/13 & 2013/14 GRA - CAC (MH) I-110 (a) - Tab h) - PUB/MH I-34 - Tab h)	Carbon Pricing	Economic Evaluation	Low
F	2012/13 & 2013/14 GRA - CAC (MH) I-14 - Tab d) - PUB/MH I-63&65 - Tab d)	Comparison IFF11-2 VS IFF10-2	Economic Evaluation	Low
F	2012/13 & 2013/14 GRA - CAC (MH) I-17 - Tab g) - PUB/MH I-68 - Tab g)	Long Term Outlook for Export Prices IFF09 to IFF11-2	Economic Evaluation	Low
F	2012/13 & 2013/14 GRA - CAC (MH) I-19 - Tab e) - PUB/MH I-66 - Tab e)	Export Revenue Assumption Changes IFF11-2	Economic Evaluation	Low
F	2012/13 & 2013/14 GRA - Exhibit MH-029-UT #25 - Tab a) PUB/MH I-63 - Tab a)	IFFMH09 to 2042 GRA 2011	Economic Evaluation	Low
F	2012/13 & 2013/14 GRA - MH Exhibit - 156 - Tab b) - PUB/MH I-65 - Tab b)	IFFMH 10-2 20 year Forecast with Revised Bipole III Costs	Economic Evaluation	Low
F	2012/13 & 2013/14 GRA - MH Exhibit #09 - Tab m) - PUB/MH I-72 - Tab m)	IFF12	Economic Evaluation	Low
F	2012/13 & 2013/14 GRA - MH Exhibit #16 - Tab n) - PUB/MH I-62 - Tab n)	MH-12-1 20 Year	Economic Evaluation	Low
F	2012/13 & 2013/14 GRA - MH Exhibit #39 - Tab 8 - PUB/MH I-78 - Tab 8	Interest Rate Risk - (Revised Based on IFF12)	Economic Evaluation	Low
F	2012/13 & 2013/14 GRA - PUB (MH) I-131 (a) - Tab 3 - PUB/MH I-73 - Tab 3	New Generation Incremental Energy Cost	Economic Evaluation	Low
F	2012/13 & 2013/14 GRA - PUB (MH) I-16 - Tab i) - PUB/MH I-69 - Tab i)	Carbon Pricing	Economic Evaluation	Low
F	2012/13 & 2013/14 GRA - PUB (MH) I-22 (a) (b) & (c) - Tab c) - PUB/MH I-63&64 - Tab c)	IFF MH11-2	Economic Evaluation	Low
F	2012/13 & 2013/14 GRA - PUB (MH) I-28 - Tab 5 - PUB/MH I-76 - Tab 5	Interest Rate Forecasting Methodology	Economic Evaluation	Low
F	2012/13 & 2013/14 GRA - PUB (MH) I-31 - Tab f) - PUB/MH I-67 - Tab f)	IFF11-2 Vs IFF10-2	Economic Evaluation	Low
F	2012/13 & 2013/14 GRA - PUB (MH) I-31 - Tab k) - PUB/MH I-67 - Tab k)	Lower Export Revenue IFF11-2 Vs IFF10-2	Economic Evaluation	Low
F	2012/13 & 2013/14 GRA - PUB (MH) I-40 (b) - Tab 4 - PUB/MH I-74 - Tab 4	Comparison Wuskwatim vs Keeyask Development Agreement	Economic Evaluation	Low
F	2012/13 & 2013/14 GRA - PUB (MH) II-10 - Tab j) - PUB/MH I-70 - Tab j)	Export Price Forecasts	Economic Evaluation	Low

F	2012/13 & 2013/14 GRA - PUB (MH) II-42 - Tab 5 - PUB/MH I-77 - Tab 5	Interest Rate Risk	Economic Evaluation	Low
F	2012/13 & 2013/14 GRA - PUB/MH I-73 - Tab 10	Incremental Revenue Requirement New Generation Investments	Economic Evaluation	Low
F	2012/13 & 2013/14 GRA - PUB/MH I-73 - Tab 10	Incremental Revenue Requirements After In service of Capital Projects - Bipole III Keeyask and Conawapa	Economic Evaluation	Low
F	2012/13 & 2013/14 GRA - PUB/MH I-84 - Tab a)	Payments to Government	Economic Evaluation	Low
F	2012/13 & 2013/14 GRA - PUB/MH I-84 - Tab b)	Payments to Governments	Economic Evaluation	Low
F	2012/13 & 2013/14 GRA - PUB/MH I-85 - Tab b)	WPLP IFF GRA 2012	Economic Evaluation	Low
F	2012/13 & 2013/14 GRA - PUB/MH I-86 - Tab c)	Wuskwatim Impacts on IFF	Economic Evaluation	Low
F	2012/13 & 2013/14 GRA - PUB/MH I-87 - Tab d)	Wuskwatim Impacts Updated	Economic Evaluation	Low
F	2012/13 & 2013/14 GRA - PUB/MH I-88 - Tab e)	Wuskwatim Revenue Calculation	Economic Evaluation	Low
F	2012/13 & 2013/14 GRA - PUB/MH I-89 - Tab f)	WPLP Debt Ratio	Economic Evaluation	Low
F	2012/13 & 2013/14 GRA - PUB/MH I-92 - Tab 17	Finance Expense Detail Components	Economic Evaluation	Low
F	2012/13 & 2013/14 GRA - Tab 4 - Appendix 4.2 - Tab I) - Not Requested - Tab I)	Consolidated Integrated Financial Forecast IFF11-2	Economic Evaluation	Low
F	PUB/MH II-35, PUB/MH I-131 (a) 2012 GRA, PUB/MH I-197, PUB Exhibit # 25 2010 GRA - PUB/MH I-73 - Tab 9	Incremental In-service Impact	Economic Evaluation	Low
F	2012/13 & 2013/14 GRA - PUB/MH I-1 - Tab 1	Load Growth Actual & Weather Normal	Load Growth	Low
F	2012/13 & 2013/14 GRA - PUB/MH I-11 - Tab 11	Price Elasticity	Load Growth	Low
F	2012/13 & 2013/14 GRA - PUB/MH I-2 - Tab 2	Population Growth	Load Growth	Low
F	2012/13 & 2013/14 GRA - PUB/MH I-3 - Tab 3	Weather Adjustment Calculations	Load Growth	Low
F	2012/13 & 2013/14 GRA - PUB/MH I-5 - Tab 5	Unit Res Consumption	Load Growth	Low
F	2012/13 & 2013/14 GRA - PUB/MH I-6 - Tab 6	Heating Load Increases	Load Growth	Low
F	2012/13 & 2013/14 GRA - PUB/MH I-7 - Tab 7	Fuel Switching Experience	Load Growth	Low
F	2012/13 & 2013/14 GRA - PUB/MH I-8 - Tab 8	Typical Space and Water Heating Costs	Load Growth	Low
F	2012/13 & 2013/14 GRA - PUB/MH I-9 & 10 - Tab 9&10	Consumer Load Growth	Load Growth	Low
F	2012/13 & 2013/14 GRA - - Tab 1	Manitoba's Clean Energy Strategy 2012	Macro – Environmental	Low
F	2012/13 & 2013/14 GRA - PUB/MH I-59 - Tab 2	GHG Estimate	Macro – Environmental	Low
F	2012/13 & 2013/14 GRA - PUB/MH I-12 - Tab 1	MISO Exports	MISO	Low
F	2012/13 & 2013/14 GRA - PUB/MH I-13 - Tab 2	MISO Exports & Imports	MISO	Low
F	2012/13 & 2013/14 GRA - PUB/MH I-14 - Tab 14	Average Unit Revenues	MISO	Low
F	2012/13 & 2013/14 GRA - PUB/MH I-14 - Tab 15	Exhibit #27 - Undertaking #22	MISO	Low
F	2012/13 & 2013/14 GRA - PUB/MH I-14 - Tab 3	Unit Export Revenues	MISO	Low
F	2012/13 & 2013/14 GRA - PUB/MH I-14 - Tab 3	Unit Export Revenues Updated IFF12	MISO	Low
F	2012/13 & 2013/14 GRA - PUB/MH I-15 - Tab 4	MISO Energy Resources	MISO	Low
F	2012/13 & 2013/14 GRA - PUB/MH I-19 - Tab 8	CCCT NG Generation vs MISO market Prices	MISO	Low
F	2012/13 & 2013/14 GRA - PUB/MH I-26 - Tab 16	Average Unit Revenue - Cost Calculation IFF12	MISO	Low
F	2012/13 & 2013/14 GRA - PUB/MH I-27 - Tab 17	Comparison of Export Price forecast details IFF09 to IFF12	MISO	Low
F	2012/13 & 2013/14 GRA - CAC (MH) II-29 (a) - Tab 17 - PUB/MH I-111 - Tab 17	SCCT Cost	Power Resource Plan	Low
F	2012/13 & 2013/14 GRA - PUB/MH I-109 - Tab 14	MIPUG (MH) I-36 (a) & (b)	Power Resource Plan	Low
F	2012/13 & 2013/14 GRA - PUB/MH I-109 - Tab 15	PUB (MH) I-133 (a) (b) (c) & (d)	Power Resource Plan	Low
F	2012/13 & 2013/14 GRA - PUB/MH I-28 -38 - Tab 1	CAC (MH) I-3 (revised)	Power Resource Plan	Low
F	2012/13 & 2013/14 GRA - PUB/MH I-28 -38 - Tab 2	Average Unit Revenue - Cost Calculation IFF12	Power Resource Plan	Low
F	2012/13 & 2013/14 GRA - PUB/MH I-28 -38 - Tab 5	Power Resource Plan 2012/13	Power Resource Plan	Low
F	2012/13 & 2013/14 GRA - PUB/MH I-28 -38 - Tab 6	Power Resource Plan 2011/12	Power Resource Plan	Low
F	2012/13 & 2013/14 GRA - PUB/MH I-42 - Tab 14	Impact of 5 Yr. & 7 Yr. Drought	Power Resource Plan	Low
F	2012/13 & 2013/14 GRA - Appendix 17 - Tab 1 - - Tab 1	Manitoba Hydro Debt Management Strategy 2012-13 and 2013-14	Public Sector Finance	Low
F	2012/13 & 2013/14 GRA - Appendix 20 - Tab 2 - PUB/MH I-96 - Tab 2	Credit Rating Agency Reports for MHEB and the Province of Manitoba	Public Sector Finance	Low
F	2012/13 & 2013/14 GRA - Credit Rating Presentations Appendix 34 - Attachment 1 - Tab 5 - PUB/MH I-96 - Tab 5	Presentation to Moody's Investors Service, May 16, 2012	Public Sector Finance	Low
F	2012/13 & 2013/14 GRA - Credit Rating Presentations Appendix 34 - Attachment 2 - Tab 6 - PUB/MH I-96 - Tab 6	Presentation to Standard & Poor's, May 30, 2012	Public Sector Finance	Low

F	2012/13 & 2013/14 GRA - Credit Rating Presentations Appendix 34 - Attachment 3 - Tab 7 - PUB/MH I-96 - Tab 7	Presentation to DBRS, August 22, 2012		Public Sector Finance	Low
F	2012/13 & 2013/14 GRA - Exhibit #21 PUB/MH II-39, PUB/MH II-41 - Tab 3 - PUB/MH I-97 - Tab 3	Financial Targets - PUB IRs (Revised Based on IFF12)		Public Sector Finance	Low
F	2012/13 & 2013/14 GRA - Exhibit #38 MIPUG/MH I-11(c) Revised - Tab 10 - PUB/MH I-99 - Tab 10	Financial Targets - MIPUG Round 1 IRs (Revised Based on IFF12)		Public Sector Finance	Low
F	2012/13 & 2013/14 GRA - MH Exhibit # 38 MIPUG (MH) I-11(c) - Tab 4 - PUB/MH I-97 - Tab 4	Financial Targets		Public Sector Finance	Low
F	2012/13 & 2013/14 GRA - PUB (MH) I-101 (a) & (b) - Tab 9 PUB/MH I-98 - Tab 9	Debt Management		Public Sector Finance	Low
F	2012/13 & 2013/14 GRA - PUB (MH) I-30 (a) (b) & (c) - Tab 13 - PUB/MH I-101 - Tab 13	Financial Targets		Public Sector Finance	Low
F	2012/13 & 2013/14 GRA - PUB (MH) I-50 - Tab 8 - PUB/MH I-100 - Tab 8	Sinking Fund		Public Sector Finance	Low
F	2012/13 & 2013/14 GRA - PUB (MH) I-67 (c) - Tab 11 - PUB/MH I-100 - Tab 11	Debt Continuity Schedule		Public Sector Finance	Low
F	2012/13 & 2013/14 GRA - PUB (MH) I-67 (g) - Tab 12 - PUB/MH I-100 - Tab 12	Debt Maturity Schedule		Public Sector Finance	Low
F	2012/13 & 2013/14 GRA - PUB(MH) II-2 - Tab 14 - PUB/MH I-102 - Tab 14	MH & Province Debt Levels		Public Sector Finance	Low
F	2012/13 & 2013/14 GRA - Appendix 42 - Tab 1 - PUB/MH I-103 - Tab 1	Wuskwatim and Keeyask Training Consortium Inc. -- Annual Report for the year ending March 31, 2010		Socio - Economic	Low
F	2012/13 & 2013/14 GRA - PUB (MH) I-10 (a) & (b) - Tab 3 - PUB/MH I-105 - Tab 3	Consulting & Mitigation Costs		Socio - Economic	Low
F	2012/13 & 2013/14 GRA - Exhibit #74 - Undertaking #48 - Tab 3 - PUB/MH I-57 - Tab 3	Need for North South AC Transmission		Transmission Issues	Low
F	2012/13 & 2013/14 GRA - MH Exhibit #98 - Undertaking #82 - Tab 4 - PUB/MH I-58 - Tab 4	Transmission Asset Condition Assessment		Transmission Issues	Low
Keeyask Generation Project - Environmental Impact Statement					
	Keeyask Generation Project - Environmental Impact Statement	Complete Package - April 2013 Update (CD-ROM)		Project Definition, General Arrangments, Rederings	Some
Additional Information Hydro Information					
W	Manitoba Hydro's governance & planning processes	Presentation to PUB workshop May 31, 2010	Governance Structure		
B	NFAT - Confidential Resource Cost Information	Annual Average Burn Cost		Burn Cost (Fuel, O&M, and GHG)	Some
September 12, 2013 Information Request to Manitoba Hydro - New Generation Construction Division					
	Project Descriptions for Keeyask and Conawapa				
W		Summary of Quantities Keeyask and Conawapa			Some
B		Actuals to Date Summary by Contract - Keeyask			High
B		Stress Test Documentation - 2012 Estimate			High
B	243953-0110-DOC-Project Execution Plan	Project Execution Plan			High
		CER History 2009 to date - Keeyask and Conawapa			Some
W					
		General Arrangment, Cross Section and Fact Sheet for Limestone, Long Spruce, and Kettle Generating Stations			
W					High
B	Keeyask Contracts	List (1 page)			Some
	Request for Proposal 016106	Keeyask Infrastructure Project - Design and Supply of Modular Buildings and Related Engineering Services			Some
B					
	Request for Proposal 016203 - Part I	Keeyask Generating Station Project - Procurement Materials - General Civil Works			
B					High
B	Request for Proposal 016203 - Part II	Keeyask G.S. - Purchaser's Construction Schedule GCC - RFP			High
B	Contract 016321	Keeyask G.S. - Design, Manufacture, Supply and Installation of Hydro T&G			High

B	Request for Direct Negotiation Proposal 016102	Keeyask Infrastructure Project - North Access Road - Part B	Some
B	Request for Direct Negotiation Proposal 016103	Keeyask Infrastructure Project - North Access Road - Part A	Some
B	Request for Direct Negotiation Proposal 016104	Keeyask Infrastructure Project - North Access road Start Up Camp Site Development and Install	Some
B	Request for Direct Negotiation Proposal 016120	Keeyask Infrastructure Project - Supply and Installation of Bridge at Look Back Creek	Some
B	Request for Direct Negotiation Proposal 016121	Keeyask Infrastructure Project - Provision for Catering and Janitorial Services for Part 1, 2, and 3	Some
B	Request for Direct Negotiation Proposal 016123	Keeyask Infrastructure Project - Provision of Security Services for Part 1 and Part 2	Some
B	Request for Direct Negotiation Proposal 016124	Keeyask Infrastructure Project - Employee Retention and Support Services for Part 1 and Part 2	Some
B	Request for Direct Negotiation Proposal 016125	Keeyask Infrastructure Project - Provision of Emergency Medical and Ambulance Services for Part 1	Some
B	Request for Direct Negotiation Proposal 016127	Keeyask Infrastructure Project - Design, Engineering, Manufacturing and Installation of the Construction Camp Facility	High
B	Request for Direct Negotiation Proposal 016132	Keeyask Infrastructure Project - Worksite Area Site Development	High
B	Services Agreement (April 9, 2013) - MH and Torch Industries		High
	Manitoba Hydro IEC Sharepoint Site		
S	Manitoba Hydro Sharepoint Site - KP	Confidential for NFAT-2012 09 06 Natural Gas Fired Powe Gryphon Report	High
S	Manitoba Hydro Sharepoint Site - KP	NFAT Confidential - Gas Turbine Operating Cost Inputs.pdf	High
S	Manitoba Hydro Sharepoint Site - KP	NFAT Confidential - Additional On-Shore Wind Projects Capital Cost Assumptions.pd	High
S	Manitoba Hydro Sharepoint Site - KP	NFAT Confidential - Checklist for 2013-11-07 Teleconference.pd	High
S	Manitoba Hydro Sharepoint Site - KP	NFAT Confidential - Discussion Points for Knight Piesold from RPMA.pdf	High
S	Manitoba Hydro Sharepoint Site - KP	NFAT Confidential - CAPEX and OPEX Est for a Generic Wind Farm in ME	High
S	Manitoba Hydro Sharepoint Site - KP	NFAT Confidential - Keeyask and Conawapa OandM Summary for KP.xlsx	High
S	Manitoba Hydro Sharepoint Site - KP	NFAT Confidential - NREL 57251 Extract.pdf	High
S	Manitoba Hydro Sharepoint Site - KP	NFAT Confidential - On Shore Wind OandM.pdf	High
S	Manitoba Hydro Sharepoint Site - KP	NFAT Confidential - Solar PV Projects O and M Costs.pdf	High
S	Manitoba Hydro Sharepoint Site - KP	NFAT Confidential - Transmission_pipeline_land_cost_assumptions_for_New_Natural_Gas_Fired_Resources.pdf	High
S	Manitoba Hydro Sharepoint Site - KP	NFAT Confidential Wind Capital Cost Estimate Basis.pdf	High
S	Manitoba Hydro Sharepoint Site - KP	NFAT Solar Capital Cost Basis.xlsx	High
S	Manitoba Hydro Sharepoint Site - KP	NREL study 57251.pdf	High
S	Manitoba Hydro Sharepoint Site - LCA	2013 Transmission Interface Capability Report OASIS Version.pdf	Low
S	Manitoba Hydro Sharepoint Site - LCA	appendix_11_3_average_unit_revenue_cost.xlsx	High
S	Manitoba Hydro Sharepoint Site - LCA	Confidential for NFAT-Alternative Resource Contingency_28dec2012.pdf	Some
S	Manitoba Hydro Sharepoint Site - LCA	Confidential for NFAT-Parametric-CCGT.pdf	Some
S	Manitoba Hydro Sharepoint Site - LCA	Confidential for NFAT-Parametric-SCGT-7FA.pdf	Some
S	Manitoba Hydro Sharepoint Site - LCA	Confidential for NFAT-Parametric-SCGT-LM6000.pdf	Some
S	Manitoba Hydro Sharepoint Site - LCA	Confidential for NFAT-Parametric-transmission gas.pdf	Some
S	Manitoba Hydro Sharepoint Site - LCA	Confidential for NFAT-Parametric-transmission wind.pdf	Some
S	Manitoba Hydro Sharepoint Site - LCA	Confidential for NFAT-Parametric-Wind.pdf	Some
S	Manitoba Hydro Sharepoint Site - LCA	Confidential for NFAT-Portfolio Capital Risk Analysis_28dec2012.pd	Some
S	Manitoba Hydro Sharepoint Site - LCA	Debt Ratio calc for La Capra.xlsx	Low
S	Manitoba Hydro Sharepoint Site - LCA	Economic, Load and Environmental Impacts of Fuel Switching in Manitoba.pd	Low
S	Manitoba Hydro Sharepoint Site - LCA	FAC-012-1 Manitoba Hydro Transfer Capability Methodology_V4.pdf	Low
S	Manitoba Hydro Sharepoint Site - LCA	Import Chart from Planning Criteria Review.xlsx	Low
S	Manitoba Hydro Sharepoint Site - LCA	Import Criteria Calculation Example.pdf	Low
S	Manitoba Hydro Sharepoint Site - LCA	Instructions for export price forcast data sheets.pdf	Low
S	Manitoba Hydro Sharepoint Site - LCA	LCA-0265_and_LCA-0266.pdf	Low
S	Manitoba Hydro Sharepoint Site - LCA	LCA0050.pdf	Low
S	Manitoba Hydro Sharepoint Site - LCA	Limiting Import Criteria by Plan.pdf	Low
S	Manitoba Hydro Sharepoint Site - LCA	MH Special Protection Systems_nfat.pdf	Low
S	Manitoba Hydro Sharepoint Site - LCA	MH Transfer Limits in the Planning Horizon_version 3.pdf	Low

S	Manitoba Hydro Sharepoint Site - LCA	MIPUG-MH I-36a-IFF12.pdf		Low
S	Manitoba Hydro Sharepoint Site - LCA	MIPUG-MH I-36b-IFF12pdf.pdf		Low
S	Manitoba Hydro Sharepoint Site - LCA	NFAT Confidential - NFAT All Gas Development Plan Builder.xls›		Low
S	Manitoba Hydro Sharepoint Site - LCA	NFAT Confidential - 2012 02 08 G190 Approval Authority Table-Wholesale Export Power Policy-final.pd		Low
S	Manitoba Hydro Sharepoint Site - LCA	NFAT Confidential - 2012 02 08 Wholesale Export Policy.pd·		Low
S	Manitoba Hydro Sharepoint Site - LCA	NFAT Confidential - 2013 All Gas Level 1 DSM.xls›		Low
S	Manitoba Hydro Sharepoint Site - LCA	NFAT Confidential - 2013 Import Development Plan.xls›		Low
S	Manitoba Hydro Sharepoint Site - LCA	NFAT Confidential - 2013 No New Resources Level 1 DSM extended Diversity.xls›		Low
S	Manitoba Hydro Sharepoint Site - LCA	NFAT Confidential - 2013 Preferred Plan Level 1 DSM.xls›		Low
S	Manitoba Hydro Sharepoint Site - LCA	NFAT CONFIDENTIAL - 2013-14 GRE Diversity Sales Analysis.pdf		Low
S	Manitoba Hydro Sharepoint Site - LCA	NFAT Confidential - All CCGT Development Plan.xlsx		Low
S	Manitoba Hydro Sharepoint Site - LCA	NFAT Confidential - All CCGT Supply and Demand Tables.pdf		Low
S	Manitoba Hydro Sharepoint Site - LCA	NFAT Confidential - Appendix 4.2_Section 3_NFAT 2012 Reference.xls›		Low
S	Manitoba Hydro Sharepoint Site - LCA	NFAT Confidential - Appendix 4.2_Section 4_NFAT 2012 Sensitivities.xls›		Low
S	Manitoba Hydro Sharepoint Site - LCA	NFAT Confidential - Appendix 4.2_Section 5_NFAT 2013 Update.xls›		Low
S	Manitoba Hydro Sharepoint Site - LCA	NFAT Confidential - Appendix 4.2_Section 6_NFAT 2013 Update DSM Sensitivities.xls›		Low
S	Manitoba Hydro Sharepoint Site - LCA	NFAT CONFIDENTIAL - Description of MH Contract Risk Analysis.pdf		Low
S	Manitoba Hydro Sharepoint Site - LCA	NFAT Confidential - Drought_References_from_the_KPMG_report.pdf		Low
S	Manitoba Hydro Sharepoint Site - LCA	NFAT Confidential - Economic Cash Flows Energy Exports V4 energy and revenue only.xls›		Low
S	Manitoba Hydro Sharepoint Site - LCA	NFAT Confidential - Economic Cash Flows.xlsx		Low
S	Manitoba Hydro Sharepoint Site - LCA	NFAT CONFIDENTIAL - Evaluation of the 2010 MH-NSP Sale.pdf		Low
S	Manitoba Hydro Sharepoint Site - LCA	NFAT Confidential - Export Power Credit Risk Management Policy Approved by EPRMC _12 09 14.pd·		Low
S	Manitoba Hydro Sharepoint Site - LCA	NFAT Confidential - Export Power Credit Risk Management Procedures Approved by EPRMC _12 09 14.pd·		Low
S	Manitoba Hydro Sharepoint Site - LCA	NFAT Confidential - FS-Report-SP-MH_TSR_76617145-76617148-Mar-2010-final.pd		Low
S	Manitoba Hydro Sharepoint Site - LCA	NFAT Confidential - ICF Final Report Sept.-2009.pdf		Low
S	Manitoba Hydro Sharepoint Site - LCA	NFAT Confidential - IFF Major Components v1.0.pdf		Low
S	Manitoba Hydro Sharepoint Site - LCA	NFAT Confidential - LCA I-0369.pdf		Low
S	Manitoba Hydro Sharepoint Site - LCA	NFAT Confidential - LCA MH I-0134-0135-0136-0137.pd·		Low
S	Manitoba Hydro Sharepoint Site - LCA	NFAT Confidential - LCA0044-45.pdf		Low
S	Manitoba Hydro Sharepoint Site - LCA	NFAT Confidential - Load Comparisons.xlsx		Low
S	Manitoba Hydro Sharepoint Site - LCA	NFAT Confidential - Manitoba Hydro External Quality Review by KPMG - Appendices.pd·		Low
S	Manitoba Hydro Sharepoint Site - LCA	NFAT Confidential - Manitoba Hydro External Quality Review by KPMG - Main Report.pd·		Low
S	Manitoba Hydro Sharepoint Site - LCA	NFAT Confidential - Moment Matching and Probability Distribution Explanation.pd		Low
S	Manitoba Hydro Sharepoint Site - LCA	NFAT Confidential - Monthly Credit Report - Sept.pdf		Low
S	Manitoba Hydro Sharepoint Site - LCA	NFAT CONFIDENTIAL - MP 250 MW Sales Evaluation Report.pdf		Low
S	Manitoba Hydro Sharepoint Site - LCA	NFAT Confidential - Ontario_Facility_Study_Report_TSR_No_76703418-76703400-76703459.pd		Low
S	Manitoba Hydro Sharepoint Site - LCA	NFAT Confidential - Optimization of Natural Gas-Fired Generation into the Manitoba Hydro System.pd·		Low
S	**Manitoba Hydro Sharepoint Site - LCA**	**NFAT Confidential - Planning Criteria Review Final Signed September 2013.pd·**		**Some**
S	Manitoba Hydro Sharepoint Site - LCA	NFAT Confidential - ProbabilityPlots.xlsx		Low
S	Manitoba Hydro Sharepoint Site - LCA	NFAT Confidential - Runoff_Methodology_Presentation_for_LCA.pdf		Low
S	Manitoba Hydro Sharepoint Site - LCA	NFAT Confidential - Sept 24 2013 - Reference Case economics.pdf		Low
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S	Manitoba Hydro Sharepoint Site - LCA	NFAT Confidential - Sept 24 2013 Financial Forecasting Model Overview.pps›		Low
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S	Manitoba Hydro Sharepoint Site - LCA	NFAT Confidential - System Planning information related to LCA Questions.pdf		Low
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S	Manitoba Hydro Sharepoint Site - LCA	TAS 2013 01.PDF		Low
S	**Manitoba Hydro Sharepoint Site - MPA**	**NFAT Confidential - Incremental IRRs - 15 Dev Plans - 9 Combinations of Energy Price and Capital Cost.xl:**	**IRR Comparison**	**Some**
S	Manitoba Hydro Sharepoint Site - PE	DC Collector System - 2020 summer peak case with 2175 exports to US - existing tie lines.pdf		Low
S	Manitoba Hydro Sharepoint Site - PE	DC Collector System - 2020 summer peak case with 2925 MW (750 MW Increase) export to US - new 500 kv tie line.pd		Low
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S	Manitoba Hydro Sharepoint Site - PE	LongTermPlan2013.pdf		Low
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S	**Manitoba Hydro Sharepoint Site - PE**	**NFAT Confidential - Keeyask-IES_Final.pdf**		**Some**

S	Manitoba Hydro Sharepoint Site - PE	NFAT Confidential - MHEB-1100 MW -V6-Preliminary.pdf			Low
S	Manitoba Hydro Sharepoint Site - PE	NFAT Confidential - SPD2011_11_Keeyask_Conawapa_Transmission_Plan_final.pdf			Low
S	Manitoba Hydro Sharepoint Site - POT	NFAT Confidential - 2012 Adjusted Electricity Export Price Forecast.xlsx			Low
S	Manitoba Hydro Sharepoint Site - POT	NFAT Confidential - 2012-13 and 2013-14 Consultant Natural Gas Price Forecasts.xlsx			Low
S	Manitoba Hydro Sharepoint Site - POT	NFAT Confidential - Brattle 2013 - Model Input and Outputs - SCN3 - Low Gas Price.xls			Low
S	Manitoba Hydro Sharepoint Site - POT	NFAT Confidential - Brattle 2013 - Model Input and Outputs - AEO Reference Case.xls			Low
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S	Manitoba Hydro Sharepoint Site - POT	NFAT Confidential - Brattle 2013 - Model Input and Outputs - SCN1 - Low CO2 Price.xls			Low
S	Manitoba Hydro Sharepoint Site - POT	NFAT Confidential - Brattle 2013 - Model Input and Outputs - SCN10 - HiGas Low CO2 Price.xls			Low
S	Manitoba Hydro Sharepoint Site - POT	NFAT Confidential - Brattle 2013 - Model Input and Outputs - SCN11 - Extreme Low.xls			Low
S	Manitoba Hydro Sharepoint Site - POT	NFAT Confidential - Brattle 2013 - Model Input and Outputs - SCN2 - High CO2 Price.xls			Low
S	Manitoba Hydro Sharepoint Site - POT	NFAT Confidential - Brattle 2013 - Model Input and Outputs - SCN4 - High Gas Price.xls			Low
S	Manitoba Hydro Sharepoint Site - POT	NFAT Confidential - Brattle 2013 - Model Input and Outputs - SCN5 - Strict Climate.xls			Low
S	Manitoba Hydro Sharepoint Site - POT	NFAT Confidential - Brattle 2013 - Model Input and Outputs - SCN6 - Non-Price Climate Policy.xls			Low
S	Manitoba Hydro Sharepoint Site - POT	NFAT Confidential - Brattle 2013 - Model Input and Outputs - SCN7 - Low Gas in Broad Market.xls			Low
S	Manitoba Hydro Sharepoint Site - POT	NFAT Confidential - Brattle 2013 - Model Input and Outputs - SCN8 - Smart Grid-Load Shifting.xls.xls			Low
S	Manitoba Hydro Sharepoint Site - POT	NFAT Confidential - Brattle 2013 - Model Input and Outputs - SCN9 - Energy Efficiency-Conservation.xls			Low
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S	Manitoba Hydro Sharepoint Site - POT	NFAT Confidential 2013Off-Peak Energyrev1.xlsx			Low
S	Manitoba Hydro Sharepoint Site - POT	NFAT Confidential 2013On-Peak Energyrev1.xlsx			Low
S	Manitoba Hydro Sharepoint Site - POT	NFAT Confidential Potomac Dependable Sales October 24 presentation.pptx			Low
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External Sources

AACE International Recommended Practice No. 69R-12	Cost Estimate	Classification System	Classification System	High
AACE International Recommended Practice No. 40R-08	Contingency Estimating - General Principles			High
AACE International Recommended Practice No. 42R-08	Risk Analysis and Contingency Detyermination Using Parametric Estimating			High
AACE International Recommended Practice No. 44R-08	Risk Analysis and Contingency Detyermination Using Expected Value			High
2007 AACE International Transactions	the Monte-Carlo Challenge: A Better Approach			High

Legend

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