

1 **SUBJECT: Capital cost; Keeyask; Conawapa; NPV**

2

3 **REFERENCE:** Economic Cash Flow spreadsheet provided on SharePoint

4

5 **PREAMBLE:** This question references documents Manitoba Hydro has labeled as  
6 commercially sensitive information.

7

8 **QUESTION:**

9 Please justify all the differences in cash flows for the capital cost to construct Conawapa and  
10 Keeyask by different in-service dates.

11

12 **RESPONSE:**

13 Refer to Appendix 11.1 in the NFAT submission pages 9, 11, 13, 15 and 17 of 18.

14 **Keeyask:**

(\$ millions)

In Service Date	Spent to Date March 31, 2012	2012 Constant Dollar Cash Flow	Escalation	Capitalized Interest	Net Expenditure
Keeyask 2019/20	\$501	\$3,678	\$368	\$962	\$5,508
Keeyask 2022/23	\$501	\$3,728	\$571	\$1,442	\$6,242
Difference	\$0	\$50	\$203	\$480	\$734

15 The \$50 Million difference in the value of the Constant Dollar Cash Flows between a Keeyask  
16 ISD of 2019/20 and 2022/23 is a result primarily of Real escalation.

17

18 **Conawapa:**

(\$ millions)

In Service Date	Spent to Date March 31, 2012	2012 Constant Dollar Cash Flow	Escalation	Capitalized Interest	Net Expenditure
Conawapa 2025/26	\$230	\$5,584	\$1,136	\$2,397	\$9,347
Conawapa 2026/27	\$230	\$5,654	\$1,271	\$2,531	\$9,685
Difference	\$0	\$70	\$135	\$134	\$338
Conawapa 2031/32	\$230	\$5,835	\$1,997	\$3,093	\$11,156
Difference	\$0	\$181	\$726	\$562	\$1,471

1 The \$70 Million difference in the value of the Constant Dollar Cash Flows between the  
2 Conawapa ISD of 2025/26 and 2026/27 is a result of \$33 Million of Real escalation and \$37  
3 Million in costs associated with additional planning and licensing.

4

5 The \$181 Million increase resulting from a 5 year deferral of the Conawapa ISD from 2026/27  
6 to 2031/32 is comprised of \$164 Million of Real escalation and \$17 Million of incremental  
7 licensing and planning costs.

1 **SUBJECT: Dependable energy; exportable surplus; firm exports**

2

3 **REFERENCE: PUB/MH I-031c**

4

5 **QUESTION:**

6 Please provide the numbers used to make the chart labeled "System Energy Supply and Firm  
7 Demand". Please provide the analogous numbers used in the 2013 Update analysis.

8

9 **RESPONSE:**

10 The following tables provide the data for the System Firm Energy and Firm Demand Chart  
11 provided in response to PUB/MH I-031c and the corresponding data for the NFAT 2013 Update  
12 K19/C26/750MW (WPS Sale & Inv) Development Plan. It should be noted that for the purposes  
13 of this chart "Existing Firm Exports" refers to signed and proposed sale agreements that are not  
14 contingent on new generation and "New Firm Exports" refers to signed and proposed sale  
15 agreements that are contingent on the new generation included in the development plan.

System Energy Supply and Firm Demand - Chart Data  
NFAT 2012 Reference  
K19/C25/750MW (WPS Sale & Inv)

	<b>Manitoba Net Load</b>	<b>Non Exportable Resources</b>	<b>Existing Firm Exports</b>	<b>New Firm Exports</b>	<b>Exportable Dependable Surplus</b>	<b>Dependable Energy</b>	<b>Average Energy</b>
2018/19	27133	1181	1804	537	271	30926	2716
2019/20	27346	962	1804	537	531	31180	2916
2020/21	27762	370	1803	1574	2946	34455	2955
2021/22	28169	489	1804	2150	2140	34752	3764
2022/23	28595	513	1803	2160	1671	34742	4008
2023/24	29054	513	1803	2160	1212	34742	3927
2024/25	29519	513	1803	2160	737	34732	3940
2025/26	29950	85	188	1758	4233	36214	3866
2026/27	30323	0	145	2571	5396	38435	5317
2027/28	30763	0	145	2737	4781	38426	6400
2028/29	31233	0	145	2737	4300	38415	6592
2029/30	31714	0	145	2737	3819	38415	6661
2030/31	32181	0	145	2737	3402	38465	6849
2031/32	32632	0	145	2737	3041	38555	6926
2032/33	33103	0	145	2737	2560	38545	7049
2033/34	33597	0	145	2737	2056	38535	7127
2034/35	34087	0	145	2737	1566	38535	7220
2035/36	34573	0	145	1701	2107	38526	7174
2036/37	35056	0	145	249	2097	37547	7822
2037/38	35542	0	145	0	1659	37346	8054
2038/39	36030	0	145	0	1210	37385	8091
2039/40	36517	0	145	0	772	37434	8144
2040/41	37003	0	145	0	324	37472	8408
2041/42	37485	0	145	0	1737	39367	6567
2042/43	37971	0	145	0	1300	39416	6669
2043/44	38457	0	145	0	853	39455	6852
2044/45	38942	0	145	0	406	39493	7150
2045/46	39427	0	145	0	1827	41399	5257
2046/47	39911	0	145	0	1381	41437	5448
2047/48	40397	0	145	0	934	41476	5631

System Energy Supply and Firm Demand  
NFAT 2013 Update  
K19/C26/750MW (WPS Sale & Inv)

	<b>Manitoba Net Load</b>	<b>Non Exportable Resources</b>	<b>Existing Firm Exports</b>	<b>New Firm Exports</b>	<b>Exportable Dependable Surplus</b>	<b>Dependable Energy</b>	<b>Average Energy</b>
2018/19	26592	1181	1804	790	504	30871	2862
2019/20	26925	962	1804	790	646	31127	3052
2020/21	27246	370	1804	1616	3376	34412	3089
2021/22	27599	489	1804	2150	2669	34711	3821
2022/23	27988	513	1803	2160	2239	34703	4028
2023/24	28372	513	1803	2160	1855	34703	4000
2024/25	28786	513	1803	2160	1431	34693	3926
2025/26	29194	85	350	1758	2857	34244	4264
2026/27	29568	0	307	2571	3897	36343	4068
2027/28	29894	0	307	2737	5778	38716	5075
2028/29	30307	0	307	2737	5355	38706	6442
2029/30	30745	0	307	2737	4917	38706	6430
2030/31	31149	0	145	2737	4488	38519	6725
2031/32	31561	0	145	2737	4096	38539	6867
2032/33	31970	0	145	2737	3677	38529	6914
2033/34	32404	0	145	2737	3233	38519	6983
2034/35	32835	0	145	2737	2802	38519	7003
2035/36	33264	0	145	1701	3400	38510	6914
2036/37	33689	0	145	249	3311	37394	7584
2037/38	34114	0	145	0	2928	37187	7771
2038/39	34543	0	145	0	2532	37220	7784
2039/40	34972	0	145	0	2146	37263	7792
2040/41	35398	0	145	0	1753	37296	7817
2041/42	35818	0	145	0	1365	37328	7851
2042/43	36239	0	145	0	986	37370	7827
2043/44	36641	0	145	0	614	37400	7879
2044/45	37043	0	145	0	242	37430	8155
2045/46	37444	0	145	0	1738	39327	6254
2046/47	37846	0	145	0	1367	39358	6362
2047/48	38248	0	145	0	995	39388	6517
2048/49	38650	0	145	0	1059	39854	6219

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1 **SUBJECT: Reservoir Operation, Drought Impacts**

2

3 **QUESTION:**

4 Please provide Manitoba Hydro's operating rules governing when to store and release water.  
5 Include rules related to seasonal operation, drought mitigation, flood control, etc.

6

7 **RESPONSE:**

8 ***Rules and Constraints Governing Manitoba Hydro Operations***

9 Manitoba Hydro's reservoir operations are restricted by a number of licences and agreements  
10 that Manitoba Hydro must abide by in the operation of all of its hydro-electric stations and  
11 water control structures. The majority of the restrictions are water level based (i.e. maximum  
12 or minimum water levels) which drive reservoir release operations. At some locations, there are  
13 also explicit constraints on flows.

14

15 One example is Manitoba Hydro's Interim Licence for Lake Winnipeg Regulation (LWR) which  
16 was issued by the Province of Manitoba as provided for under the Manitoba Water Power Act.  
17 In addition to other matters, the Licence sets requirements for the control of outflows from  
18 Lake Winnipeg, based on its elevation:

- 19
- 20 • When the lake level is between 711-715 feet, outflows set to meet the requirements for  
power production on the Nelson River.
  - 21 • When the lake level is above 715 feet, Manitoba Hydro must operate at maximum  
22 discharge until 715 feet is reached.
  - 23 • When the lake level is below 711 feet, Manitoba Hydro must operate outflow as  
24 ordered by the Minister responsible for the Water Power Act.

25 In addition to the licence constraints on Manitoba Hydro operations, there are also physical  
26 based limits that constrain operations, for example minimum reservoir levels that are required  
27 to ensure the structural integrity of a dam, or maximum reservoir drawdown rates that are in

1 place to maintain the integrity of dyke structures. Manitoba Hydro includes all of these  
2 restrictions in planning the operation of its system of reservoirs and generating stations.

3

4 ***IRs from Previous Hearings that Address Operations***

5 Please refer to copies of IR responses from past GRAs and Risk Review (see page 8 of 36 to page  
6 36 of 36) where Manitoba Hydro addressed questions related to its operations; related IR  
7 responses are appended to the end of this response and listed in Table 1 below.

- 1 Table 1. IR responses from past GRAs and Risk Review where Manitoba Hydro addressed
- 2 questions related to its operations

PUB Hearing	IR Response
2010-11 and 2011-12 GRA and Risk Review	PUB/MH I-77(a) PUB/MH I-77(c) PUB/MH I-78(b) PUB/MH I-79(b) PUB/MH I-79(c) PUB/MH I-82(b) PUB/MH I-83(a) PUB/MH I-83(c) PUB/MH I-90(c) PUB/MH I-91 PUB/MH I-92(c) PUB/MH I-163(a) PUB/MH I-163(b) PUB/MH II-74(a-c) PUB/MH II-76 PUB/MH II-136(b) PUB/MH II-136(g) PUB/MH RISK-31(a) CAC/MSOS/MH/RISK-13 CAC/MSOS/MH/RISK-83 MIPUG/MH/RISK-2
2012 GRA	MIPUG/MH I-43 PUB/MH I-133 PUB/MH II-92(a) PUB/MH II-92(b) PUB/MH II-92(c) PUB/MH II-92(d)

1 ***Quantification of Drought Risk***

2 Related to Manitoba Hydro's quantification of drought risk, the [KPMG report](http://www.pub.gov.mb.ca/exhibits/mh-4-7.pdf)  
3 (<http://www.pub.gov.mb.ca/exhibits/mh-4-7.pdf>) concluded at pages xxii and later in the  
4 document:

5 "On the basis of the policy decisions in place with respect to risk tolerance, Manitoba Hydro  
6 quantifies its drought risk appropriately and currently provides for appropriate levels of  
7 reserves of risk capital against its projected drought risk."

8

9 KPMG went on to state at page 96 of their report:

10 "Manitoba Hydro's use of actual flow sequences to measure drought risk is consistent with  
11 practices at other utilities and avoids the need to develop statistical models of underlying  
12 water flow processes."

13

14 On page 119 of the KPMG report, KPMG provided the following conclusion about SPLASH (for  
15 planning and estimating the cost of drought) and other Manitoba Hydro models:

16 "With respect to the modeling approach at Manitoba Hydro, based on our analysis, we  
17 find:

- 18 • Manitoba Hydro has developed a suite of models that capture the key  
19 characteristics of the Manitoba Hydro system. These models are used to help  
20 optimize system operations and to support long-term capacity planning.
- 21 • We are satisfied that MH has taken appropriate care and due diligence in developing  
22 and maintaining these models and in using them in its operations planning process.
- 23 • Manitoba Hydro's current approach to forecasting and to calculating dependable  
24 energy appears reasonable and is consistent with practices at other North American  
25 hydroelectric utilities. It is reasonable to rely on historical flow data for estimating  
26 dependable energy."

1 On page 120 of the September 2009 ICF Report, “Independent Review of Manitoba Hydro  
2 Export Power Sales and Associated Risks”, ICF concluded:

3 “The current methodology of assessment and systems employed by the Corporation to  
4 develop the financial estimate of risks associated with an extended drought are reasonable.  
5 They reflect a sustained commitment of the organization to quantification of the risks  
6 related to droughts, especially related to the amount of hydroelectric power likely to be  
7 available and the resulting financial impact from decreased hydroelectric supply. As well,  
8 the stress case examined by the Corporation is comparable to practices adopted by other  
9 industries.”

10

11 Also, please refer to page 61 of ICF Direct Evidence (Manitoba Hydro Exhibit #55 -  
12 <http://www.pub.gov.mb.ca/exhibits/mh-55.pdf>) from the 2010-11 and 2011-12 GRA and Risk  
13 Review entitled, “Review of MH’s Quantification of Risk Exposure Related to an Extended  
14 Drought” where ICF concluded that:

15 “Manitoba Hydro’s quantification of risk exposure to drought via use of a historically based  
16 five year episode is reasonable.”

17

### 18 ***Review of MH Operations During the 2002-2004 Drought***

19 The root cause of Manitoba Hydro’s financial losses in 2003/04 was drought as a result of a  
20 prolonged period of below normal precipitation across much of the Nelson-Churchill River  
21 basin. This resulted in an extended period of below normal inflows to the Manitoba Hydro  
22 system, as illustrated in Figure 5.8 of the submission, inflows in 2002/03 were below average  
23 and inflows in 2003/04 were only 62% of average. The deficit in hydraulic supply required  
24 Manitoba Hydro to secure alternate supplies from the market at market prices in order to meet  
25 its firm load obligations.

1 Risk Advisory in its January 2005 report entitled “2002-2004 Drought Risk Management  
2 Review” of Manitoba Hydro’s drought operations concluded on page 35:

3 “Overall, the Company did an outstanding job in managing the drought. There is an  
4 inappropriate tendency to apply 20/20 hindsight to risk management decisions. However,  
5 any judgment must be based on market circumstances at the time, and the need to manage  
6 both financial and reliability risks. While the Company did incur incremental costs to avoid  
7 draining reservoirs, it did so for the sole purpose of protecting the Manitoba consumer from  
8 potential outages in the future.”

9

10 Also, please refer to page 56 of ICF Direct Evidence (Manitoba Hydro Exhibit #55 -  
11 <http://www.pub.gov.mb.ca/exhibits/mh-55.pdf>) from the 2010-11 & 2011-12 GRA and Risk  
12 Review entitled, “Review of MH’s Management of the 2003/2004 Drought”.

13

#### 14 ***What Drought Risk Factors are Different Today/Tomorrow vs. 2002-2004 Drought***

15 Please refer to Manitoba Hydro’s responses to LCA/MH II-462 and LCA/MH II-463. In addition,  
16 please refer to pages 57 and 59 of ICF Direct Evidence (Manitoba Hydro Exhibit #55 -  
17 <http://www.pub.gov.mb.ca/exhibits/mh-55.pdf>) from the 2010-11 & 2011-12 GRA and Risk  
18 Review. On page 59, entitled, “MH’s Capability to Respond to a Drought Has Significantly  
19 Evolved Since the 2003-04 Drought”, ICF highlighted differences between a number of drought  
20 risk related factors between 2003/04 and 2010/11. Aside from the water supply and load-  
21 dependent factors (which change from year to year) there are a number of other factors that  
22 have changed for the better since 2003/04 that reduce Manitoba Hydro’s financial drought  
23 risks, namely:

- 24 • Manitoba Hydro now has access to a liquid open market (MISO) as opposed to being limited  
25 to bilateral purchases as it was in 2003/04.

- 1 • Manitoba Hydro can now purchase power using brokerage services thereby sheltering itself  
2 from non-competitive pricing; in the absence of a broker, the seller may command a higher  
3 price from Manitoba Hydro given it would be aware of general water supply conditions in  
4 the Manitoba Hydro system.
  
- 5 • Manitoba Hydro now owns all northbound firm transmission service which increases the  
6 reliability of imports and reduces Manitoba Hydro's financial exposure related to using  
7 another party's transmission service.

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1 **2010-11 and 2011-12 GRA and Risk Review PUB/MH I-77**

2

3 **Subject: Tab 8: Energy Supply**

4 **Reference: Tab 8, Energy Supply, Page 17 of 20, Figure 8.6.2**

5

6 **a) Please confirm that in February of most years, MH commits to summer peak export**  
7 **energy sales, but only if energy in storage is above 8,000 GWh. Explain what other**  
8 **factors (e.g. actual winter precipitation) are employed.**

9

10 **ANSWER:**

11

12 Manitoba Hydro may commit to export sales in February for the subsequent spring and summer  
13 season, but has no specific requirement related to 8,000 GWh of energy in reservoir storage. The  
14 main factor that enables these sales is that under worst case conditions Manitoba Hydro has  
15 surplus energy available to serve the sale. The determination of this surplus includes energy-in-  
16 storage levels, and basin snow pack conditions. For example in the springs of 2005, 2008 and  
17 2009, near record flood forecasts were issued for the Red River, which meant that MH could  
18 with confidence predict that inflows to Manitoba Hydro's reservoirs in those years would be  
19 above dependable inflow conditions.

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1 **2010-11 and 2011-12 GRA and Risk Review PUB/MH I-77**

2

3 **Subject: Tab 8: Energy Supply**

4 **Reference: Tab 8, Energy Supply, Page 17 of 20, Figure 8.6.2**

5

6 **c) Please confirm that MH assumes long-term average energy inflows of 50 GWh/month**  
7 **for the second half of the fiscal year and anticipates drawing about 6,000 GWh from**  
8 **energy in storage. If not, please explain what other factors are employed.**

9

10 **ANSWER:**

11

12 Manitoba Hydro can confirm that the referenced Figure 8.6.2, entitled “Daily Gross Energy from  
13 Inflow Indicator” indicates that on average, the daily inflow is around 50 GWh/day or 1,500  
14 GWh/month for the second half of the fiscal year.

15

16 In addition, Manitoba Hydro can confirm that Figure 8.6.3 entitled “Total Energy in Reservoir  
17 Storage” indicates that there is an average storage draw down of almost 7,000 GWh for the  
18 period of October 1 to April 1.

19

20 However, Manitoba Hydro does not use either of these numbers in planning its power system  
21 operations.

1 **2010-11 and 2011-12 GRA and Risk Review PUB/MH I-78**

2

3 **Subject: Tab 8: Energy Supply**

4 **Reference: Tab 8, Energy Supply, Page 17 of 20, Lines 7 and 8**

5

6 **b) Why does MH no longer consider the 10,000 GWh as of April as a constraint**  
7 **benchmark for increased export sales? Was the energy in storage calculation revised**  
8 **after 2003/04?**

9

10 **ANSWER:**

11

12 Manitoba Hydro is not aware of a reference to 10,000 GWh in April as a constraint for export  
13 sales. Interruptible export sales are predominantly a function of the spring and summer water  
14 supply. Also, refer to PUB/MH I-82(d).

1 **2010-11 and 2011-12 GRA and Risk Review PUB/MH I-79**

2

3 **Subject: Tab 8: Energy Supply**

4 **Reference: 2008/09 Power Resource Plan and Tab 8 (Pages 16/17/18 of 20)**

5

6 **b) Explain what specific weighting is given to the spring flow conditions and energy-in-**  
7 **storage in each watershed.**

8

9 • **Winnipeg River.**

10 • **Red River.**

11 • **Saskatchewan River.**

12 • **Burntwood River.**

13 • **Other inflow.**

14

15 **ANSWER:**

16

17 Manitoba Hydro does not apply weights to spring flow conditions nor to energy in storage in its  
18 various watersheds.

---

1 **2010-11 and 2011-12 GRA and Risk Review PUB/MH I-79**

2

3 **Subject: Tab 8: Energy Supply**

4 **Reference: 2008/09 Power Resource Plan and Tab 8 (Pages 16/17/18 of 20)**

5

6 **c) Does MH regularly monitor or define on a watershed basis the following:**

7

8 • **Precipitation (October to February)?**

9 • **Spring precipitation (March/April)?**

10 • **Summer precipitation (May to September)?**

11 • **Summer evaporation from reservoirs (May to September)?**

12

13 **ANSWER:**

14

15 Manitoba Hydro generally monitors precipitation on a business-day basis. Each week Manitoba  
16 Hydro reviews the system and basin weighted average precipitation reports for varying  
17 durations:

18

19 1. the past week;

20 2. the past 60 days; and

21 3. seasonal cumulative values (April 1<sup>st</sup> through October 31<sup>st</sup> or November 1<sup>st</sup> through  
22 March 31<sup>st</sup>).

23

24 Evaporation is implicitly monitored through a lake local inflow which is calculated using  
25 measured inflow, outflow and water level.

---

1 **2010-11 and 2011-12 GRA and Risk Review PUB/MH I-82**

2

3 **Subject: Tab 8: Energy Supply**

4 **Reference: Exhibit #17 (2007/03/11) Tab 8 – Energy Supply**

5

6 **b) Please explain the role that energy in storage plays as a significant input to MH's**  
7 **annual hydraulic generation forecasts.**

8

9 **ANSWER:**

10

11 Illustrating and tracking storage in terms of energy is meaningful to monitor aggregate storage  
12 conditions for a system of reservoirs used for hydro-electric production.

13

14 Energy in storage is not an explicit input to the annual hydraulic generation forecast. Instead,  
15 energy in storage is modeled by using current water levels, consistent with actual conditions at  
16 the time of the forecast. To this water supply is added the forecast of inflows to the system,  
17 which in combination is the available water supply used to produce hydraulic generation  
18 forecasts.

1 **2010-11 and 2011-12 GRA and Risk Review PUB/MH I-83**

2

3 **Subject: Tab 8: Energy Supply**

4 **Reference: Exhibit #17 27/03/11**

5

6 **a) Does MH contemplate a zero energy in storage scenario during**

7

8 **i. A one-year drought? Explain.**

9 **ii. A two-year drought? Explain.**

10 **iii. A five-year drought? Explain.**

11 **iv. A seven-year drought? Explain.**

12

13 **ANSWER:**

14

15 Manitoba Hydro does not contemplate a zero energy in storage situation either from a planning  
16 or operating perspective regardless of the extent of drought. Without water in storage, Manitoba  
17 Hydro could not operate its hydraulic system.

---

1 **2010-11 and 2011-12 GRA and Risk Review PUB/MH I-83**

2

3 **Subject: Tab 8: Energy Supply**

4 **Reference: Exhibit #17 27/03/11**

5

6 **c) What minimum energy in storage level April 1, May 1, and June 1 would MH look for**  
7 **in contemplating the annual achievement of:**

8

9 **i. 33,000 GWh of hydraulic generation?**

10 **ii. 29,000 GWh of hydraulic generation?**

11 **iii. 25,000 GWh of hydraulic generation?**

12

13 **ANSWER:**

14

15 The amount of hydro-electric energy Manitoba Hydro can produce in a year is largely dependent  
16 on the amount of precipitation and resulting runoff (or inflow) occurring in that year. It is  
17 therefore not possible to respond to this question without defining the inflow conditions.

18

19 In general, Manitoba Hydro does not contemplate a specific annual achievement of hydraulic  
20 generation in any given year. However, Manitoba Hydro does plan its operations to ensure  
21 storage levels are, at minimum, sufficient to supply firm domestic and export load under the  
22 most severe drought of record inflow condition. For a single year worst drought commencing on  
23 April 1<sup>st</sup>, the minimum useable energy storage amount is approximately 3 TWh.

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1 **2010-11 and 2011-12 GRA and Risk Review PUB/MH I-90**

2

3 **Subject: Tab 8: Energy Supply**

4 **Reference: PUB/MH I-3(f)**

5

6 **d) Can MH confirm that above average Winnipeg River and Red River spring runoff would**  
7 **typically ensure average or above average overall hydraulic output? Explain.**

8

9 **ANSWER:**

10

11 No. Above average spring runoff does not guarantee above average hydraulic output for the year.  
12 Other significant factors include: spring precipitation, summer precipitation, fall precipitation,  
13 and carry over reservoir storage from the previous year. Moreover, the Winnipeg and Red River  
14 basins only make up a portion of the larger Nelson / Churchill River Basin that supplies  
15 Manitoba Hydro's hydraulic generation stations.

---

1 **2010-11 and 2011-12 GRA and Risk Review PUB/MH I-91**

2  
3 **Subject: Tab 8: Energy Supply**

4 **Reference: Tab 8 – Energy Supply Page 17/18.**

5  
6 **Please confirm that MH's operational decision process relies on:**

- 7
- 8 **i. Actual flows (unweighted) within the major stream system (Winnipeg River, Red**
  - 9 **River, Saskatchewan River, and Burntwood River).**
  - 10 **ii. Spring and summer peak flow hydrographs that are of a predictable shape so that by**
  - 11 **reference to a peak discharge, the upcoming fall and winter hydraulic generation can**
  - 12 **be predicted.**
  - 13 **iii. Local inflows (other than four major streams) being more than sufficient to counter**
  - 14 **evaporation losses from reservoirs (e.g., Lake Winnipeg).**
  - 15 **iv. Limiting the size of the individual export sales commitments that can be made without**
  - 16 **reference to the Division Manager.**
  - 17 **v. Please provide any additional factors.**
- 18

19 **ANSWER:**

- 20
- 21 **i. Confirmed. Actual river flows within the major stream system (*that includes* Winnipeg**
  - 22 **River, Red River, Saskatchewan River, and Burntwood River) are a key input to the**
  - 23 **operations planning process.**
  - 24
  - 25 **ii. No. Upcoming fall and winter hydraulic generation is not predicted by reference to a**
  - 26 **peak discharge experienced in the spring and summer periods. Refer to 2010 GRA**
  - 27 **PUB/MH I-81 for further explanation.**
  - 28
  - 29 **iii. No. The operations planning process relies on a water supply forecasting technique**
  - 30 **utilizing regression analysis that accounts for all the inputs and losses in the hydrologic**
  - 31 **cycle.**
  - 32
  - 33 **iv. No. Operations planning decisions are separate from management controls that limit**
  - 34 **export sales commitments. The operations planning process does require that all export**
  - 35 **sale and purchase commitments be included.**

- 1 v. There are numerous other non-technical factors and technical factors that are considered  
2 in the operations planning process. These include but are not limited to:  
3  
4 a. License, legal and citizenship obligations to all stakeholders affected by Manitoba  
5 Hydro's operations,  
6 b. Public safety, energy security and environmental stewardship considerations  
7 which all involve the exercise of professional judgment and experience,  
8 c. Current storage levels, near term weather forecasts, equipment maintenance  
9 schedules, domestic load forecasts, ice conditions, availability of extra-provincial  
10 tie-line capacity and short term market trends and needs.

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1 **2010-11 and 2011-12 GRA and Risk Review PUB/MH I-92**

2

3 **Subject: Tab 8: Energy Supply**

4 **Reference: Tab 8 – Energy Supply (Page 17, Figure 8.6.2)**

5

6 **c) Is winter and spring precipitation directly employed as an input into MH’s operational**  
7 **modelling? Explain.**

8

9 **ANSWER:**

10

11 No. Precipitation is not a direct input into Manitoba Hydro’s operations planning models.  
12 Precipitation is implicitly included in Manitoba Hydro’s modeling in the form of observed  
13 stream flows. Very recent precipitation information is used qualitatively to monitor overall basin  
14 conditions.

---

1 **2010-11 and 2011-12 GRA and Risk Review PUB/MH I-163**

2

3 **Subject: Tab 12: Corporate Risk Management**

4 **Reference: ICF Report, Chapter 9.0 (Pages 118 to 120)**

5

6 **a) Please provide an overview of MH's planning approach to defining system constraints**  
7 **in drought years, average years, and high flow years.**

8

9 **ANSWER:**

10

11 Manitoba Hydro's planning approach is to ensure that there is sufficient energy and capacity  
12 supplies available at all times to meet its firm load and reserve obligations. To the extent that  
13 Manitoba Hydro has surplus supplies available, these surpluses are scheduled for sale to the  
14 various external markets in a manner such that Manitoba Hydro's net revenues are maximized.  
15 In scheduling the production of electricity, Manitoba Hydro recognizes all the constraints of its  
16 generating, transmission and export systems including; safety, reliability, legal and licenses as  
17 well as the physical characteristics of the reservoirs, rivers and water control structures.

18

19 In drought years, Manitoba Hydro is faced with the uncertainty of the magnitude and duration of  
20 the drought as there is no guarantee that the historic flow record includes the worst drought  
21 possible. To maintain the highest level of supply security, Manitoba Hydro adopts a conservation  
22 strategy which preserves reservoir storages to the extent possible given the availability of  
23 alternate supplies. Specifically, reservoir releases are managed on the assumption that forecast  
24 inflows will be at the lower 90% confidence level in the current year, that 1940/41 inflows will  
25 occur in the second year, that winter weather and electricity demand will be at the upper 90%  
26 confidence level and that imports will be relied on only to the extent there is firm transmission  
27 available.

28

29 In non drought years, energy security is not an issue as Manitoba Hydro is not in an energy short  
30 situation and the power system can be operated normally.

---

1 **2010-11 and 2011-12 GRA and Risk Review PUB/MH I-163**

2

3 **Subject: Tab 12: Corporate Risk Management**

4 **Reference: ICF Report, Chapter 9.0 (Pages 118 to 120)**

5

6 **b) Please provide a detailed process outline of MH operational modelling to define**  
7 **surplus energy at various times of the years, e.g.:**

8

9 **i. February (precipitation/energy in storage).**

10 **ii. April (precipitation/energy in storage).**

11 **iii. July (runoff/energy in storage).**

12 **iv. October (runoff/energy in storage).**

13

14 **ANSWER:**

15

16 On a weekly basis, Manitoba Hydro prepares a production forecast for the generating system for  
17 a period as long as 16 months into the future. This forecast indicates the generation plans for  
18 each of Manitoba Hydro's facilities and any import and export transactions necessary to serve  
19 Manitoba Hydro's load obligations. Inputs into this forecast are Manitoba Hydro's reservoir  
20 storages plus its current water supply forecast for the planning period. Should Manitoba Hydro  
21 have surplus energy supplies available, these are scheduled for sale into the external markets in a  
22 manner that maximizes Manitoba Hydro's net export revenue. This process is updated weekly,  
23 adjusting on a continuous basis for current water, market and other conditions. The production  
24 plan also consists of a set of reservoir releases that reflect those necessary to accommodate  
25 Manitoba Hydro's various stakeholders, anticipated releases from upstream reservoir operators,  
26 and license requirements as well as those needed for economic power system operation.

---

**2010-11 and 2011-12 GRA and Risk Review PUB/MH II-74**

**Subject: Tab 8: Energy Supply**

**Reference: PUB/MH I-77(a), (b), (c), (d) - System Energy Storage Depletion**

**Please provide a detailed explanation of MH's actual energy operational parameters and constraints (e.g., rule curve) used to determine surplus energy available for export in:**

**a) April-May period.**

**b) June-September period.**

**c) October-March period.**

**ANSWER:**

As explained in PUB/MH I-77, with respect to rule curve, Manitoba Hydro plans its operations to ensure useable storage levels are, at minimum, sufficient to supply firm domestic and export load under the most severe single year historic drought of record inflow condition. This useable energy storage requirement is effectively a rule curve level.

Manitoba Hydro plans its operations to export surplus energy (i.e. energy in excess of the reserve requirement) in the highest valued periods to the extent possible subject to constraints and operational parameters. Of the periods listed in this information request, higher export prices generally occur in the June-September period. To account for uncertainty in key parameters such as future inflows and Manitoba Load, Manitoba Hydro uses conservative assumptions prior to committing to sell this surplus energy under contract.

As explained in PUB/MH I-91, in addition to inflows, the constraints and operational parameters that impact the operations planning process include, but are not limited to:

- a. license, legal and citizenship obligations to all stakeholders affected by Manitoba Hydro's operations;
- b. public safety, energy security and environmental stewardship considerations which all involve the use of professional judgment and experience; and
- c. current storage levels, near term weather forecasts, equipment maintenance schedules, domestic load forecasts, ice conditions, availability of extraprovincial tie-line capacity and short term market trends and needs.

---

**2010-11 and 2011-12 GRA and Risk Review PUB/MH II-76**

**Subject: Tab 8: Energy Supply**

**Reference: PUB/MH I-77(a), (b), (c), (d) Actual Energy Operations**

**Please define on a monthly basis for the 2002-03 and 2003/04 years, MH's decision process based on the then available specific data on:**

- **Actual accumulated winter snow pack (inches).**
- **Actual accumulated spring and summer rainfall (inches).**
- **Lake Winnipeg partial inflows (cfs/GWh).**
- **Lake Winnipeg water levels.**
- **System energy-in-storage (GWh).**
- **Total hydraulic generation (GWh).**
- **Total imports and thermal generation (GWh).**
- **Total exports (GWh).**

**ANSWER:**

Manitoba Hydro's rationale for managing the 2003/04 drought was tested during the 2004 PUB rate hearing. Please refer to the transcripts of that hearing for the details. In addition, Manitoba Hydro had its operations reviewed by an independent consultant as requested by the PUB.

The Manitoba Hydro 2002-2004 Drought Risk Management Review was filed with the PUB on May 3, 2005 and re-filed as Appendix 43 of the 2008 GRA. The document can be found at:

[http://www.hydro.mb.ca/regulatory\\_affairs/electric/gra\\_08\\_09/information\\_requests/Appendix\\_43-Report\\_on\\_2002-2004\\_Drought.pdf](http://www.hydro.mb.ca/regulatory_affairs/electric/gra_08_09/information_requests/Appendix_43-Report_on_2002-2004_Drought.pdf)

The review addresses Manitoba Hydro's energy portfolio management activities as they pertained to the drought experienced by Manitoba Hydro from 2002-2004. In both reviews, Manitoba Hydro's actions were deemed to be prudent and in the best interests of the Manitoba rate payer.

Please also refer to explanations of Manitoba Hydro's operations planning decision process provided in PUB/MH I-91 and PUB/MH I-163. Manitoba Hydro respectfully declines to provide a more detailed response to this question.

---

1 **2010-11 and 2011-12 GRA and Risk Review PUB/MH II-136**

2

3 **Subject: Tab 12: Corporate Risk Management**

4 **Reference: Tab 12, Sections 12.1 and 12.2, Pages 1/2/3 Drought Operations**

5

6 **b) What parameters does MH employ to predict an impending drought? List and**  
7 **explain.**

8

9 **ANSWER:**

10

11 Droughts are not predictable and Manitoba Hydro does not rely on its predictive ability in  
12 protecting Manitoba Hydro from the risk of drought. Instead of operating based on predictive  
13 ability, Manitoba Hydro plans its operations considering the full range of possible future water  
14 supply conditions. Sufficient storage reserves are maintained such that firm demand and exports  
15 can be supplied during the most severe single-year drought of record. Relating specifically to  
16 water supply, Manitoba Hydro's operations planning process considers the following parameters:

17

- 18 a. historical record of inflow conditions – used to establish the severity of dry conditions  
19 that are possible in the future;
- 20 b. current usable energy in reservoir storage;
- 21 c. existing inflow conditions – tributary flows into the Churchill and Nelson River basins;
- 22 d. accumulated snowpack conditions – extreme snowpack conditions (high or low) correlate  
23 to spring runoff; and
- 24 e. accumulated rainfall - recent rainfall information is used qualitatively to monitor overall  
25 basin conditions.

---

1 **2010-11 and 2011-12 GRA and Risk Review PUB/MH II-136**

2  
3 **Subject: Tab 12: Corporate Risk Management**

4 **Reference: Tab 12, Sections 12.1 and 12.2, Pages 1/2/3 Drought Operations**

5  
6 **g) What specific actions would MH undertake if October energy-in-storage fell below**  
7 **average? Explain.**

8  
9 **ANSWER:**

10  
11 The response to this question is dependent on numerous factors including, but not limited to what  
12 is the useable energy in storage (*i.e.*, how much below average), inflow conditions, forecast  
13 Manitoba load, export contract commitments, thermal generation availability, import capability,  
14 etc.

15  
16 If energy in storage is below average in October but not well below average, Manitoba Hydro  
17 may still be exporting power in the off-peak period depending on inflow conditions.

18  
19 Regardless of the water supply condition, Manitoba hydro will operate in accordance with the  
20 System Operations Priorities as provided in the response to PUB/MH I-147(a)(ii), where Priority  
21 1 is to maintain firm energy supply. Depending on the severity of the water supply conditions,  
22 including current storage and inflows, Manitoba Hydro continuously evaluates the need to, and  
23 merit of, taking the following actions:

- 24  
25 • decreased off-peak exports;  
26 • increased off-peak imports;  
27 • financial settlement of existing on-peak export contracts;  
28 • hedging to mitigate price risk for imports and/or gas costs;  
29 • increased on-peak imports;  
30 • operation of gas-fired generation; and  
31 • operation of coal-fired generation (as permitted under *The Climate Change and Emissions*  
32 *Reductions Act*).

33  
34 Some or all of the above actions could be invoked at any point in the year if deemed necessary to  
35 protect firm energy supply.

---

1 **2010-11 and 2011-12 GRA and Risk Review PUB/MH/RISK-31**

2

3 **Reference: PUB/MH II-75; PUB/MH II-90**

4 **Risk Issue: Energy from Storage**

5

6 **a) Please confirm that in defining dependable energy MH typically assumes every**  
7 **drought year will commence with an April 1st average energy-in-storage of 8,000**  
8 **GWh; and therefore, MH is targeting to retain at least average energy-in-storage at**  
9 **the end of March.**

10

11 **ANSWER:**

12

13 Manitoba Hydro cannot confirm that it is targeting to retain 8,000 GW.h of energy in storage.  
14 Given that the annual energy from inflow in the most severe drought is approximately  
15 15,500 GW.h and that dependable hydraulic energy is 21,000 GW.h, it could be concluded that  
16 Manitoba Hydro requires about 5,500 GW.h in storage at the end on March that can be utilized  
17 over the next year of low flows assuming financial settlements and additional market supplied  
18 energy are ignored as supply sources.

19

20 For operational planning purposes, Manitoba Hydro assumes that a portion of its long term  
21 export contracts will be financially settled and that some market supplied energy will be  
22 available in determining its energy reserve requirements.

---

1 **2010-11 and 2011-12 GRA and Risk Review PUB/MH/RISK-31**

2

3 **Reference: PUB/MH II-75; PUB/MH II-90**

4 **Risk Issue: Energy from Storage**

5

6 **b) Please confirm that in above average flow years, it should be almost always possible**  
7 **to sustain an outflow from energy-in-storage of 8,000 GWh over an eight-month**  
8 **(August to March) period.**

9

10 **ANSWER:**

11

12 Manitoba Hydro cannot confirm that it is able to sustain an 8,000 GWh draw from energy-in-  
13 storage in above average flow years from August to March.

14

15 In above average inflow years the outflow capability from Lake Winnipeg is insufficient to  
16 achieve a significant draw (if any) from storage for power purposes. 2010/11 is a good example  
17 of this situation when the draw for power purposes (in spite of maximum outflows at Jenpeg)  
18 will be limited to 225 GWh by March 31, 2011 due to ice restrictions in the Lake Winnipeg  
19 outlet channels. When storage draws from Cedar Lake and Southern Indian Lake of 2,000 GWh  
20 are included the total storage draw is 2,225 GWh.

21

22 Manitoba Hydro does not control the storage draw on all the other major reservoirs in the  
23 Nelson-Churchill watershed.

---

1 **2010-11 and 2011-12 GRA and Risk Review CAC/MSOS/MH/RISK-13**

2

3 **Reference: KPMG Report, pages 42 - 43**

4

5 **a) Please explain further the basis for the D.R.S. Is it based on a one-year drought (i.e.**  
6 **the inflow for 1940/41)? Exactly at what point in time – looking forward – is the low**  
7 **flow assumed to start?**

8

9 **ANSWER:**

10

11 The Drought Reserve Storage requirement is based on 1940/41 inflow condition which is  
12 assumed to start on April 1<sup>st</sup> of the fiscal year following the “operating horizon.” Manitoba  
13 Hydro plans its operations through the operating horizon such that the energy in reservoir storage  
14 at the end of the horizon exceeds the DRS. The operating horizon ends on March 31<sup>st</sup> and is  
15 extended in the fall to include the second year; hence the operating horizon is generally between  
16 5 and 17 months in duration.

---

1 **2010-11 and 2011-12 GRA and Risk Review CAC/MSOS/MH/RISK-83**

2  
3 **Reference: KPMG Report, pages (viii) and 42**

- 4  
5 **a) The Report states that following a draw down, water storage levels will be**  
6 **replenished at the first opportunity, including from opportunity sales and other**  
7 **non-firm sources. Please describe more fully Manitoba Hydro' practices in the this**  
8 **regard and, particular, whether Manitoba Hydro's approach to weighing the cost of**  
9 **replenishing water storage levels relative to the future risk of inadequate supply.**

10  
11 **ANSWER:**

12  
13 Maintaining energy security is one of Manitoba Hydro's highest operating priorities. In order to  
14 ensure adequate energy supplies for drought as well as other contingencies Manitoba Hydro  
15 maintains hydraulic energy reserves in its storage reservoirs adequate to meet its projected needs  
16 during severe conditions, consistent with its energy security operating criteria. If in planning its  
17 operations it is necessary to draw into its hydraulic reserves projected at the end of the planning  
18 period, rather than curtail supply before that time, Manitoba Hydro will draw from those reserves  
19 first. Should conditions subsequently improve, Manitoba Hydro will re-establish these planning  
20 reserves first prior to reducing other supply plans.

21  
22 Please also refer to Manitoba Hydro's operating priorities in Attachment 1 to PUB/MH I-  
23 147(a)(ii).

---

1 **2010-11 and 2011-12 GRA and Risk Review MIPUG/MH/RISK-2**

2

3 **KPMG April 2010 Report and Appendices: Forecasting Models**

4

5 **d) Please provide additional discuss on MH’s perspectives with respect to the**  
6 **comments on page 114 of the KPMG report – specifically:**

7

8 **i. Does MH agree with KPMG’s observation that management’s tendency to**  
9 **maintain higher water levels will result in somewhat greater risk of the**  
10 **“spill” of water in subsequent periods? Please discuss.**

11

12 **ANSWER:**

13

14 Manitoba Hydro’s priorities place energy supply security above economics. Therefore Manitoba  
15 Hydro accepts the increased risk of future spill and potential costs that result from maintaining  
16 higher storage levels, if this incremental storage is required to ensure a secure supply of energy  
17 for its customers under pessimistic inflow and weather conditions. Please see Manitoba Hydro’s  
18 operating priorities in Attachment 1 to PUB/MH I-147(a)(ii). Therefore Manitoba Hydro agrees  
19 with KPMG’s observation.

1 **2012 GRA MIPUG/MH I-43**

2

3 **Subject: Appendix 4.2-Consolidated Integrated Financial Forecast IFF11-2**

4

5 **d) Please provide a detailed explanation of the approach to determining the “expected”**  
6 **conditions.**

7

8 **ANSWER:**

9

10 The expected inflow conditions for the beginning of the second year of the IFF11-2 (2012/13)  
11 were based on a regression relationship between antecedent precipitation conditions (explanatory  
12 variable) versus future spring Hydraulic Energy from Inflows (HEFI) as the dependent variable.  
13 The observed precipitation (% of normal) from September 2011 to March 2012 (the antecedent  
14 condition) was applied to the regression relationship to determine the expected April to June  
15 2012 HEFI. The remaining fiscal year volume from July 2012 to March 2013 was defined using  
16 a second regression relationship between June HEFI (as the explanatory variable) predicting July  
17 to March HEFI (as the dependent variable).

---

1 **2012 GRA PUB/MH I-133**

2

3 **Reference: 2010 GRA – Risk Scenarios PUB/MH I-150/2011/12 Power Resource Plan**  
4 **Drought Risk Reserves**

5

6 **d) Please provide MH’s Drought Mitigation Plan or alternatively define the**  
7 **appropriate steps that MH intends to undertake to minimize the financial impacts of**  
8 **both a five year and seven year drought.**

9

10 **ANSWER:**

11

12 Manitoba Hydro operates and dispatches its generation fleet and manages its export obligations  
13 on an ongoing and continuous basis in a manner that maximizes net revenue while maintaining a  
14 reliable and dependable supply for Manitobans. This practice is used under all water conditions,  
15 including during droughts. So to the extent that the cost of drought can be mitigated this goal will  
16 be achieved as a matter of course.

17

18 During lower flow and drought conditions when hydraulic supplies are insufficient to meet the  
19 provincial demand, Manitoba Hydro augments the hydraulic supply with more expensive thermal  
20 or purchased electricity, whether produced in province or in the extra-provincial markets. Under  
21 extremely low flow conditions Manitoba thermal generation may be dispatched in order to  
22 provide voltage or contingency support. Additional energy beyond these reliability needs is  
23 generally purchased in the external markets given that Manitoba thermal generation is generally  
24 much more expensive than energy purchased in the external markets.

25

26 Under drought conditions The Climate Change and Emissions Reduction Act permits Manitoba  
27 Hydro to operate the coal fired unit at Brandon G.S. The decision to operate the station during  
28 extreme drought conditions will be made at that time by the Executive of Manitoba Hydro  
29 having considered all the relevant factors. Should Manitoba Hydro elect to operate the coal fired  
30 unit, there may be some cost savings to the Corporation depending upon whether Brandon coal  
31 fired energy displaces higher priced market energy.

32

33 To the extent that Manitoba Hydro is exposed to additional financial risk during drought as a  
34 result of uncertain market and natural gas prices, Manitoba Hydro may choose to hedge that risk  
35 by purchasing electricity/natural gas forward contracts or options. The decision to hedge to  
36 manage Manitoba Hydro’s financial risk will be made by the Executive of Manitoba Hydro  
37 having considered all the relevant factors at that time.

1 **2012 GRA PUB/MH II-92**

2

3 **Reference: PUB/MH I-133 (d) Drought Management**

4

5 **a) Please confirm that MH does not have a formal drought mitigation plan and does**  
6 **not intend to put one in place.**

7

8 **ANSWER:**

9

10 As a predominantly hydraulic utility MH plans all of its operations to in effect act as a Drought  
11 Plan. It should be recognized however that once a drought has commenced that it cannot be  
12 mitigated. They are naturally occurring events, their timing and magnitude cannot be predicted  
13 and Manitoba Hydro cannot change the volume of water available at any time including during  
14 drought periods. Given those realities, Manitoba Hydro builds new generating plant, maintains  
15 the readiness of its existing generation fleet and operates its reservoir storages at all times so that  
16 under a repeat of historic worst drought conditions it has or will have adequate energy supplies to  
17 meet its firm load obligations without having to declare an energy emergency.

18

19 To the extent that the cost of drought can be mitigated Manitoba Hydro does so through its  
20 normal operating practices of managing reservoir storages, dispatching its generation fleet and  
21 managing its export obligations and market activities in a manner that maximizes net revenue  
22 while maintaining a reliable and dependable supply for Manitobans. This practice is continuous,  
23 ongoing and is used under all water conditions, not just during droughts.

1 **2012 GRA PUB/MH II-92**

2

3 **Reference: PUB/MH I-133 (d) Drought Management**

4

5 **b) Please confirm that MH does not employ a precipitation-runoff prediction process**  
6 **in order to anticipate a pending drought, but rather employs actual flows and**  
7 **reservoir at specific times in the year to confirm the existence of a drought.**

8

9 **ANSWER:**

10

11 Manitoba Hydro does not rely on its predictive ability, whether based upon precipitation or  
12 stream flow forecasting, to anticipate droughts.

13

14 Manitoba Hydro can confirm that its operational planning process relies on measured river flows  
15 and reservoir inflows as the basis for its decision making process.

---

1 **2012 GRA PUB/MH II-92**

2

3 **Reference: PUB/MH I-133 (d) Drought Management**

4

5 **c) Please provide the specific processes and parameters (e.g. in April and September)**  
6 **that MH employs to determine the existence of a drought situation.**

7

8 **ANSWER:**

9

10 Manitoba Hydro monitors basin wide precipitation (seasonal, last 60 days, last week, daily), river  
11 flows, and reservoir inflows throughout the year. This information provides input into Manitoba  
12 Hydro's antecedent forecasting procedures which produces water supply forecasts for the  
13 balance of the year. These forecasts, as well as forecasts of other key inputs such as water  
14 storage levels, reserve targets, committed load, market, and generator and transmission outages  
15 are inputs to the HERMES model. Results from the HERMES model include revenue and cost  
16 inputs to the IFF.

17

18 The existence of a drought can be indicated by:

19

- 20 a) Cumulative and current water supply conditions relative to long term normals, and  
21 b) Net export revenues variance compared to those forecast in the IFF. Significant financial  
22 variations associated with below average water conditions are indicative of drought.

23

24 Manitoba Hydro reviews current conditions, updates forecasts and prepares operating plan  
25 updates on a weekly basis. The Manitoba Hydro executive is provided water supply condition  
26 update reports on a weekly basis. The Export Power Risk Management Committee meets  
27 quarterly to review current water conditions and updated net export revenue projections for the  
28 balance of the year under a range of scenarios. During periods of significant drought the EPRMC  
29 reviews the situation more frequently.

30

31 For additional information on Manitoba Hydro's antecedent forecasting procedures and the  
32 HERMES model please review Chapter 3 of the Manitoba Hydro External Quality Review,  
33 "Forecasting Models", dated April 15, 2010.

---

1 **2012 GRA PUB/MH II-92**

2

3 **Reference: PUB/MH I-133 (d) Drought Management**

4

5 **d) Please confirm that because MH does not attempt to predict drought situations**  
6 **there is only minimal opportunity to mitigate the cost of an imminent drought.**

7

8 **ANSWER:**

9

10 Not confirmed.

11

12 Manitoba Hydro is well-prepared to recognize the onset of drought and to take actions  
13 appropriate to address current and potential water supply conditions. As explained in part c) of  
14 this question, Manitoba Hydro continually monitors conditions as a normal course of business  
15 and responds weekly through appropriate revisions to its operating plans.

16

17 However, because precipitation and river flows are mean reverting and because Manitoba Hydro  
18 protects against worst case drought conditions, in most circumstances Manitoba Hydro's actions,  
19 although justified, are conservative with resultant additional costs or lost opportunity costs. This  
20 is because on average water conditions do improve and in some cases, such as in the spring-fall  
21 2010 period, to such an extent that water held back in storage due to concern about low inflows,  
22 is subsequently spilled as the result of flood inflows.

1 **SUBJECT: Drought Impact, MISO**

2

3 **QUESTION:**

4 Please describe how Manitoba Hydro could use the MISO market to mitigate the financial  
5 impact from a drought.

6

7 **RESPONSE:**

8 Manitoba Hydro relies on its gas fired thermal generation at Brandon and Selkirk for  
9 dependable energy during droughts.

10

11 Compared to energy purchased in the MISO market this Manitoba supply is relatively  
12 expensive. For example, the heat rate at both stations under base load operations is at least  
13 12.5 Dth/MWh plus start up costs. Assuming a gas cost of \$4/Dth, the pure energy cost from  
14 these facilities is \$50/MWh. The average implied heat rate in the MISO market is about 8  
15 Dth/MWh which with the same cost of gas would result in a cost of \$32/MWh for a market  
16 purchase. So on the average, burning gas in Manitoba for energy purposes is at least 56% more  
17 expensive than purchased energy. This is a result of the difference in heat rates, and is true  
18 regardless of the cost of natural gas.

19

20 Recognizing this situation, Manitoba Hydro can mitigate the financial impact of the drought by  
21 purchasing energy from MISO either to serve Manitoba load or to meet its export contract  
22 obligations. In order to achieve this, following the opening of the MISO standard market in  
23 2005, Manitoba Hydro negotiated amendments to most existing export agreements giving  
24 Manitoba Hydro the flexibility to make an economic choice to supply energy from its own  
25 resources or to purchase lower priced energy from the MISO market. Provisions to financially  
26 settle obligations have been included in all new agreements negotiated after 2005.

1 Further, since the drought, Manitoba Hydro has purchased all available MISO northbound  
2 transmission service between MISO and Manitoba. Previously this service was owned by  
3 Manitoba Hydro export counterparties which meant Manitoba Hydro had to involve them in  
4 any purchases that used this transmission service. With the ownership of these transmission  
5 positions, Manitoba Hydro can now purchase energy on an as-needed hourly basis directly from  
6 the MISO market without involving a third party. As a result Manitoba Hydro no longer has to  
7 rely on fixed price multi-hour arrangements traditionally only available on a bilateral basis.

1 **SUBJECT: Drought Impact, MISO**

2

3 **QUESTION:**

4 How would the 2003 drought have been managed differently if Manitoba Hydro had the MISO  
5 market available to it.

6

7 **RESPONSE:**

8 During the 2003 drought Manitoba Hydro did not own the MISO northbound transmission  
9 service reservations, the MISO market did not exist and Manitoba Hydro's bilateral export  
10 contracts had to be served at the border. Therefore the full benefits of the current situation  
11 described in the response to LCA/MH II-462 were not available. It should be noted that even  
12 without having these options, Manitoba Hydro was still able to achieve significant savings  
13 through bilateral arrangements to purchase energy which avoided base load operations of its  
14 natural gas fired generators.

1 **SUBJECT: Reservoir Operation**

2

3 **QUESTION:**

4 Please provide the references to the risk review proceeding discussed on the November 13,  
5 2013 call with La Capra Associates.

6

7 **RESPONSE:**

8 Please refer to the following links and linked documents from the 2010-11 & 2011-12 GRA and  
9 Risk Review hearing:

10 ***References***

11 2010/11 and 2011/12 Rates and Risk Review Hearing:

12 <http://www.pub.gov.mb.ca/mhgra-index.html>

13

14 Exhibit #MH-4-7 KPMG's April 2010 Report and Appendices:

15 <http://www.pub.gov.mb.ca/exhibits/mh-4-7.pdf>

16

17 Exhibit #MH-61 KPMG Direct Evidence:

18 <http://www.pub.gov.mb.ca/exhibits/mh-61.pdf>

19

20 Exhibit #MH-55 ICF Direct Testimony:

21 <http://www.pub.gov.mb.ca/exhibits/mh-55.pdf>

1 **SUBJECT: Reservoir Operation; opportunity sales**

2

3 **PREAMBLE:** Please provide the following monthly historical data from the year 2000  
4 through the time with the latest available data. Please provide the data in electronic  
5 spreadsheet format.

6

7 **QUESTION:**

8 Opportunity imports in MWh, separately for off-peak and peak periods.

9

10 **RESPONSE:**

11 The response to this Information Request includes Commercially Sensitive Information and has  
12 been filed in confidence with the Public Utilities Board.

1 **SUBJECT: Reservoir Operation; opportunity sales**

2

3 **PREAMBLE:** Please provide the following monthly historical data from the year 2000  
4 through the time with the latest available data. Please provide the data in electronic  
5 spreadsheet format.

6

7 **QUESTION:**

8 Opportunity import costs in dollars, separately for off-peak and peak periods.

9

10 **RESPONSE:**

11 The response to this Information Request includes Commercially Sensitive Information and has  
12 been filed in confidence with the Public Utilities Board.

1 **SUBJECT: Reservoir Operation; opportunity sales**

2

3 **PREAMBLE:** Please provide the following monthly historical data from the year 2000  
4 through the time with the latest available data. Please provide the data in electronic  
5 spreadsheet format.

6

7 **QUESTION:**

8 Opportunity exports in MWh, separately for off-peak and peak periods.

9

10 **RESPONSE:**

11 The response to this Information Request includes Commercially Sensitive Information and has  
12 been filed in confidence with the Public Utilities Board.

1 **SUBJECT: Reservoir Operation; opportunity sales**

2

3 **PREAMBLE:** Please provide the following monthly historical data from the year 2000  
4 through the time with the latest available data. Please provide the data in electronic  
5 spreadsheet format.

6

7 **QUESTION:**

8 Opportunity export revenues in dollars, separately for off-peak and peak periods.

9

10 **RESPONSE:**

11 The response to this Information Request includes Commercially Sensitive Information and has  
12 been filed in confidence with the Public Utilities Board.

1 **SUBJECT: New Cases**

2

3 **PREAMBLE:** This question references documents Manitoba Hydro has labeled as  
4 commercially sensitive information. For the new All CCGT Case with the buildout shown  
5 in the following:

Date: November 12, 2013																		
System Firm Winter Peak Demand and Capacity Resources (MW) @ generation																		
NFAT 2012 Reference																		
All Combined Cycle Gas																		
Fiscal Year	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
<b>Power Resources</b>																		
<b>New Power Resources</b>																		
New Hydro																		
Conawapa																		
Keeyask																		
1	<b>Total New Hydro</b>																	
New Thermal																		
SCGT																		
CCGT																		
2	<b>Total New Thermal</b>																	
New Imports																		
Contracted																		
Proposed																		
3	<b>Total New Imports</b>																	
4	<b>Total New Power Resources</b> 1+2+3																	
<b>Base Supply Power Resources</b>																		
Existing Hydro																		
Existing Thermal																		
Brandon Coal - Unit 5																		
Selkirk Gas																		
Brandon Units 6-7 SCGT																		
Contracted Imports																		
Proposed Imports																		
Pointe du Bois Rebuild																		
Bipole III Reduced Losses																		
5	<b>Total Base Supply Power Resources</b>																	
6	<b>Total Power Resources</b> 4+5																	
<b>Peak Demand</b>																		
2012 Base Load Forecast																		
Less: 2012 Base DSM Forecast																		
7	<b>Manitoba Net Load</b>																	
Contracted Exports																		
Proposed Exports																		
8	<b>Total Exports</b>																	
9	<b>Total Peak Demand</b> 7+8																	
10	<b>Reserves</b>																	
11	<b>System Surplus</b> 6-9-10																	
12	<b>Less: Brandon Unit 5</b>																	
<b>Exportable Surplus</b> 11+12																		

Date: November 12, 2013																		
System Firm Winter Peak Demand and Capacity Resources (MW) @ generation																		
NFAT 2012 Reference																		
All Combined Cycle Gas																		
Fiscal Year	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36	2036/37	2037/38	2038/39	2039/40	2040/41	2041/42	2042/43	2043/44	2044/45	2045/46	2046/47	2047/48
<b>Power Resources</b>																		
<b>New Power Resources</b>																		
New Hydro																		
Conawapa																		
Keeyask																		
<b>1</b>	<b>Total New Hydro</b>																	
New Thermal																		
SCGT																		
CCGT																		
<b>2</b>	1 071	1 071	1 071	1 071	1 428	1 428	1 428	1 428	1 785	1 785	1 785	2 142	2 142	2 142	2 499	2 499	2 499	2 499
<b>2</b>	<b>Total New Thermal</b>																	
New Imports																		
Contracted																		
Proposed																		
<b>3</b>	<b>Total New Imports</b>																	
<b>4</b>	<b>Total New Power Resources</b> 1+2+3																	
	1 071	1 071	1 071	1 071	1 428	1 428	1 428	1 428	1 785	1 785	1 785	2 142	2 142	2 142	2 499	2 499	2 499	2 499
<b>Base Supply Power Resources</b>																		
Existing Hydro																		
Existing Thermal																		
Brandon Coal - Unit 5																		
	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132
	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280
Selkirk Gas																		
Brandon Units 6-7 SCGT																		
Contracted Imports																		
Proposed Imports																		
Pointe du Bois Rebuild																		
	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43
Bipole III Reduced Losses																		
	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
<b>5</b>	<b>Total Base Supply Power Resources</b>																	
	5 722	5 722	5 722	5 722	5 722	5 722	5 722	5 722	5 722	5 722	5 722	5 722	5 722	5 722	5 722	5 722	5 722	5 722
<b>6</b>	<b>Total Power Resources</b> 4+5																	
	6 793	6 793	6 793	6 793	7 150	7 150	7 150	7 150	7 507	7 507	7 507	7 864	7 864	7 864	8 221	8 221	8 221	8 221
<b>Peak Demand</b>																		
2012 Base Load Forecast																		
	5947	6 032	6 116	6 200	6 284	6 368	6 452	6 537	6 621	6 705	6 789	6 873	6 957	7 042	7 126	7 210	7 294	7 378
Less: 2012 Base DSM Forecast																		
	-190	-189	-185	-178	-172	-166	-161	-154	-146	-138	-131	-124	-117	-110	-102	-95	-88	-81
<b>7</b>	<b>Manitoba Net Load</b>																	
	5 757	5 843	5 931	6 022	6 112	6 202	6 291	6 383	6 475	6 567	6 658	6 749	6 840	6 932	7 024	7 115	7 206	7 297
Contracted Exports																		
Proposed Exports																		
<b>8</b>	<b>Total Exports</b>																	
<b>9</b>	<b>Total Peak Demand</b> 7+8																	
	5 757	5 843	5 931	6 022	6 112	6 202	6 291	6 383	6 475	6 567	6 658	6 749	6 840	6 932	7 024	7 115	7 206	7 297
<b>10</b>	<b>Reserves</b>																	
	691	701	712	723	733	744	755	766	777	788	799	810	821	832	843	854	865	876
<b>11</b>	<b>System Surplus</b> 6-9-10																	
	345	249	150	48	305	204	104	1	255	152	50	305	203	100	354	252	150	48
<b>12</b>	<b>Less: Brandon Unit 5</b>																	
<b>Exportable Surplus</b> 11+12	345	249	150	48	305	204	104	1	255	152	50	305	203	100	354	252	150	48

Date: November 12, 2013		System Firm Energy Demand and Dependable Resources (GWh) @ generation																		
		NFAT 2012 Reference All Combined Cycle Gas																		
Fiscal Year		2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	
<b>Power Resources</b>																				
<b>New Power Resources</b>																				
New Hydro																				
Conawapa																				
Keeyask																				
Notigi																				
Manasan																				
Early Morning																				
First Rapids																				
1	<b>Total New Hydro</b>																			
New Thermal																				
SCGT																				
CCGT																				
2	<b>Total New Thermal</b>												2 706	2 706	2 706	2 706	5 412	5 412	5 412	5 412
New Imports																				
Contracted																				
Proposed																				
3	<b>Total New Imports</b>																			
4	<b>New Wind</b>																			
5	<b>Total New Power Resources</b> 1+2+3+4												2 706	2 706	2 706	2 706	5 412	5 412	5 412	5 412
<b>Base Supply Power Resources</b>																				
Existing Hydro		21 697	21 950	21 940	21 930	21 910	21 890	21 880	21 860	21 850	21 840	21 830	21 830	21 820	21 810	21 810	21 800	21 790	21 790	
Existing Thermal																				
Brandon Coal - Unit 5		811	811	811	811	811	811	811	592											
Selkirk Gas		953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	
Brandon Units 6-7 SCGT		2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	
Contracted Imports		2 705	2 705	1 949	1 549	1 639	1 639	1 639	1 639	1 639	1 639	1 639	1 639	1 639	271					
Proposed Imports				781	936	936	936	936	936	936	936	936	936	155						
Hydro Adjustment		340	340	373	784	844	844	844	844	844	844	844	844	844	139					
Market Purchases		363	363	338	583	493	493	493	493	493	493	493	493	2 617	3 043	3 068	3 068	3 068		
Existing Wind		766	777	777	777	777	777	777	777	777	777	777	777	777	777	777	777	777		
Pointe du Bois Rebuild																				
Bipole III Reduced Losses								239	239	239	239	239	239	239	239	239	239	239	239	
6	<b>Total Base Supply Power Resources</b>	29 989	30 253	30 276	30 677	30 717	30 936	30 926	30 687	30 085	30 075	30 065	30 065	30 055	29 315	29 176	29 191	29 181	29 181	
7	<b>Total Power Resources</b> 5+6	29 989	30 253	30 276	30 677	30 717	30 936	30 926	30 687	30 085	30 075	32 771	32 771	32 761	32 021	34 588	34 603	34 593	34 593	
<b>Manitoba Domestic Load</b>																				
2012 Base Load Forecast		24 961	25 734	26 071	26 393	26 677	27 128	27 616	27 919	28 400	28 859	29 322	29 779	30 239	30 691	31 138	31 594	32 053	32 511	
Construction Power - Hydro																				
Less: 2012 Base DSM Forecast		- 62	- 173	- 271	- 356	- 436	- 509	- 583	- 643	- 693	- 740	- 782	- 805	- 820	- 841	- 865	- 866	- 850	- 832	
Demand Side Management Aggressive																				
8	<b>Manitoba Net Load</b>	24 899	25 561	25 800	26 037	26 241	26 619	27 033	27 276	27 707	28 119	28 540	28 974	29 419	29 860	30 293	30 758	31 233	31 714	
Contracted Exports		3 293	3 156	3 156	2 115	2 012	2 012	2 012	2 012	2 012	2 012	2 012	2 012	2 012	249	145	145	145	145	
Proposed Exports				162	162	162	162	162	162	162	162	162	162	162						
Less: Adverse Water		- 91			- 309	- 370	- 370	- 370	- 370	- 370	- 370	- 370	- 370	- 370	- 61					
9	<b>Total Net Exports</b>	3 202	3 156	3 156	1 968	1 804	1 804	1 804	1 804	1 804	1 804	1 804	1 804	1 804	188	145	145	145	145	
10	<b>Total Energy Demand</b> 8+9	28 101	28 717	28 956	28 005	28 045	28 423	28 837	29 080	29 511	29 923	30 344	30 778	31 223	30 048	30 438	30 903	31 378	31 859	
11	<b>System Surplus</b> 7-10	1 888	1 536	1 320	2 672	2 672	2 513	2 089	1 607	574	152	2 427	1 993	1 538	1 973	4 150	3 700	3 215	2 734	
12	Less: Brandon Unit 5	- 811	- 811	- 811	- 811	- 811	- 811	- 811	- 592											
13	Adverse Water	- 91			- 309	- 370	- 370	- 370	- 370	- 370	- 370	- 370	- 370	- 370	- 61					
	<b>Exportable Surplus</b> 11+12+13	986	725	509	1 552	1 491	1 332	908	645	204	2 057	1 623	1 168	1 912	4 150	3 700	3 215	2 734		

Date: November 12, 2013																		
System Firm Energy Demand and Dependable Resources (GWh) @ generation																		
NFAT 2012 Reference All Combined Cycle Gas																		
Fiscal Year	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36	2036/37	2037/38	2038/39	2039/40	2040/41	2041/42	2042/43	2043/44	2044/45	2045/46	2046/47	2047/48
<b>Power Resources</b>																		
<b>New Power Resources</b>																		
<b>New Hydro</b>																		
Conawapa																		
Keeyask																		
Notigi																		
Manasan																		
Early Morning																		
First Rapids																		
1	<b>Total New Hydro</b>																	
<b>New Thermal</b>																		
SCGT																		
CCGT																		
2	<b>Total New Thermal</b>																	
<b>New Imports</b>																		
Contracted																		
Proposed																		
3	<b>Total New Imports</b>																	
4	<b>New Wind</b>																	
5	<b>Total New Power Resources</b> 1+2+3+4																	
<b>Base Supply Power Resources</b>																		
<b>Existing Hydro</b>																		
<b>Existing Thermal</b>																		
Brandon Coal - Unit 5																		
Selkirk Gas																		
Brandon Units 6-7 SCGT																		
Contracted imports																		
Proposed imports																		
Hydro Adjustment																		
Market Purchases																		
6	<b>Total Base Supply Power Resources</b>																	
7	<b>Total Power Resources</b> 5+6																	
<b>Manitoba Domestic Load</b>																		
2012 Base Load Forecast																		
Construction Power - Hydro																		
Less: 2012 Base DSM Forecast																		
Demand Side Management Aggressive																		
8	<b>Manitoba Net Load</b>																	
Contracted Exports																		
Proposed Exports																		
Less: Adverse Water																		
9	<b>Total Net Exports</b>																	
10	<b>Total Energy Demand</b> 8+9																	
11	<b>System Surplus</b> 7-10																	
12	Less: Brandon Unit 5																	
13	Adverse Water																	
<b>Exportable Surplus</b> 11+12+13																		

1 **QUESTION:**

2 Please provide an update to the NPV output tables in Appendix 9.3 with the results of all 27  
3 cases or confirm the tables provided in the Attachment to this question are correct.

4

5 **RESPONSE:**

6 The economics attachment included by La Capra with this Information Request contains an  
7 error as well as commercially sensitive information. This attachment has been corrected and a  
8 publicly disclosable version in the form of economics tables provided in the NFAT submission  
9 Appendix 9.3 as well as an updated S Curve is provided as Attachment 1. The supply/demand  
10 tables provided by LCA in this Information Request are correct and have been included as  
11 Attachment 2.

12

13 The remaining information required to respond to this Information Request contains  
14 Commercially Sensitive Information has been filed confidence with the PUB.













































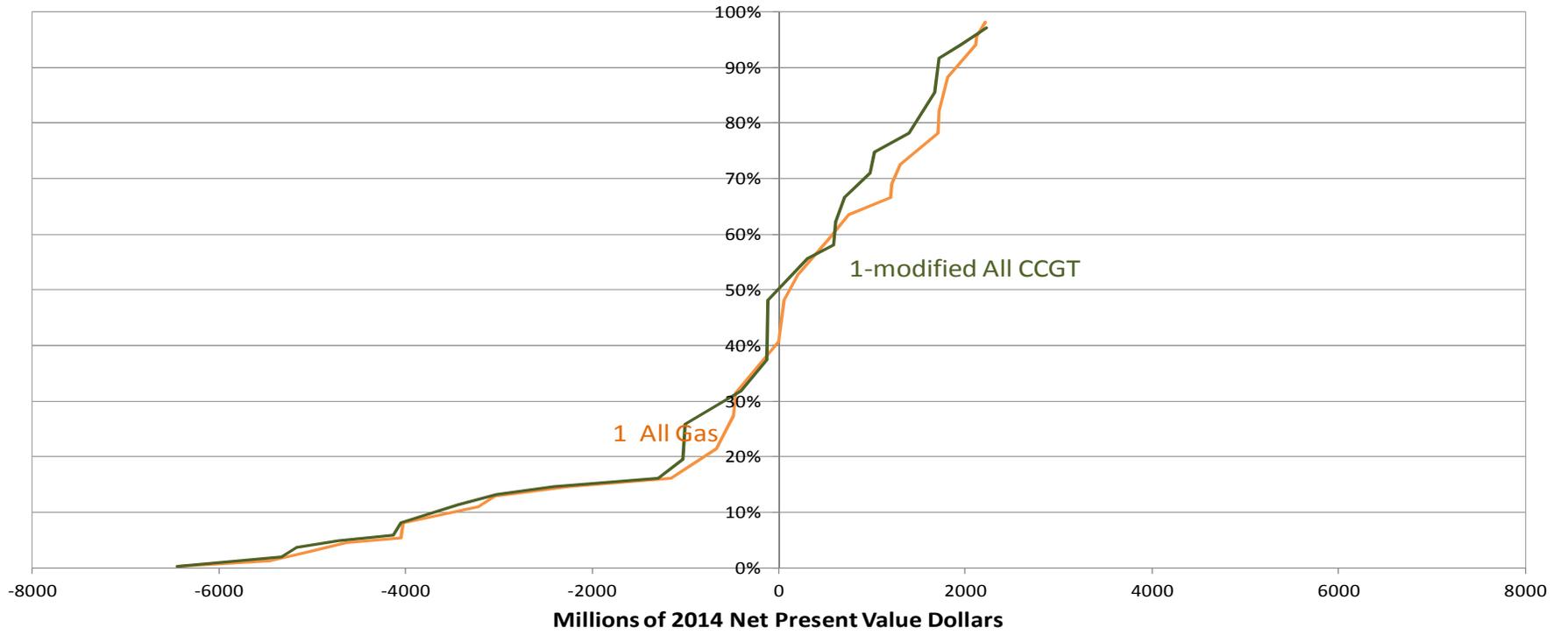












Date: November 12, 2013

**System Firm Winter Peak Demand and Capacity Resources (MW) @ generation  
NFAT 2012 Reference  
All Combined Cycle Gas**

Fiscal Year	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
<b>Power Resources</b>																		
<b>New Power Resources</b>																		
New Hydro																		
Conawapa																		
Keeyask																		
1	<b>Total New Hydro</b>																	
New Thermal																		
SCGT																		
CCGT																		
2	<b>Total New Thermal</b>																	
New Imports																		
Contracted																		
Proposed																		
3	<b>Total New Imports</b>																	
4	<b>Total New Power Resources</b> 1+2+3																	
<b>Base Supply Power Resources</b>																		
Existing Hydro																		
Existing Thermal																		
Brandon Coal - Unit 5																		
Selkirk Gas																		
Brandon Units 6-7 SCGT																		
Contracted Imports																		
Proposed Imports																		
Pointe du Bois Rebuild																		
Bipole III Reduced Losses																		
5	<b>Total Base Supply Power Resources</b>																	
6	<b>Total Power Resources</b> 4+5																	
<b>Peak Demand</b>																		
2012 Base Load Forecast																		
Less: 2012 Base DSM Forecast																		
7	<b>Manitoba Net Load</b>																	
Contracted Exports																		
Proposed Exports																		
8	<b>Total Exports</b>																	
9	<b>Total Peak Demand</b> 7+8																	
10	Reserves																	
11	<b>System Surplus</b> 6-9-10																	
12	Less: Brandon Unit 5																	
<b>Exportable Surplus</b> 11+12																		

Date: November 12, 2013

**System Firm Winter Peak Demand and Capacity Resources (MW) @ generation**  
**NFAT 2012 Reference**  
**All Combined Cycle Gas**

Fiscal Year	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36	2036/37	2037/38	2038/39	2039/40	2040/41	2041/42	2042/43	2043/44	2044/45	2045/46	2046/47	2047/48
<b>Power Resources</b>																		
<b>New Power Resources</b>																		
New Hydro																		
Conawapa																		
Keeyask																		
1	<b>Total New Hydro</b>																	
New Thermal																		
SCGT																		
CCGT																		
2	1 071	1 071	1 071	1 071	1 428	1 428	1 428	1 428	1 785	1 785	1 785	2 142	2 142	2 142	2 499	2 499	2 499	2 499
2	<b>Total New Thermal</b>																	
New Imports																		
Contracted																		
Proposed																		
3	<b>Total New Imports</b>																	
4	<b>Total New Power Resources</b> 1+2+3																	
	<b>1071</b>	<b>1 071</b>	<b>1 071</b>	<b>1 071</b>	<b>1 428</b>	<b>1 428</b>	<b>1 428</b>	<b>1 428</b>	<b>1 785</b>	<b>1 785</b>	<b>1 785</b>	<b>2 142</b>	<b>2 142</b>	<b>2 142</b>	<b>2 499</b>	<b>2 499</b>	<b>2 499</b>	<b>2 499</b>
<b>Base Supply Power Resources</b>																		
Existing Hydro																		
Existing Thermal																		
Brandon Coal - Unit 5																		
Selkirk Gas																		
Brandon Units 6-7 SCGT																		
Contracted Imports																		
Proposed Imports																		
Pointe du Bois Rebuild																		
Bipole III Reduced Losses																		
5	<b>Total Base Supply Power Resources</b>																	
6	<b>Total Power Resources</b> 4+5																	
	<b>5177</b>	<b>5 177</b>																
	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132
	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280
	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43
	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90	90
5	<b>5 722</b>	<b>5 722</b>	<b>5 722</b>	<b>5 722</b>	<b>5 722</b>	<b>5 722</b>	<b>5 722</b>	<b>5 722</b>	<b>5 722</b>	<b>5 722</b>	<b>5 722</b>	<b>5 722</b>	<b>5 722</b>	<b>5 722</b>	<b>5 722</b>	<b>5 722</b>	<b>5 722</b>	<b>5 722</b>
6	<b>6 793</b>	<b>6 793</b>	<b>6 793</b>	<b>6 793</b>	<b>7 150</b>	<b>7 150</b>	<b>7 150</b>	<b>7 150</b>	<b>7 507</b>	<b>7 507</b>	<b>7 507</b>	<b>7 864</b>	<b>7 864</b>	<b>7 864</b>	<b>8 221</b>	<b>8 221</b>	<b>8 221</b>	<b>8 221</b>
<b>Peak Demand</b>																		
2012 Base Load Forecast																		
Less: 2012 Base DSM Forecast																		
7	<b>Manitoba Net Load</b>																	
Contracted Exports																		
Proposed Exports																		
8	<b>Total Exports</b>																	
9	<b>Total Peak Demand</b> 7+8																	
	5947	6 032	6 116	6 200	6 284	6 368	6 452	6 537	6 621	6 705	6 789	6 873	6 957	7 042	7 126	7 210	7 294	7 378
	-190	-189	-185	-178	-172	-166	-161	-154	-146	-138	-131	-124	-117	-110	-102	-95	-88	-81
7	<b>5 757</b>	<b>5 843</b>	<b>5 931</b>	<b>6 022</b>	<b>6 112</b>	<b>6 202</b>	<b>6 291</b>	<b>6 383</b>	<b>6 475</b>	<b>6 567</b>	<b>6 658</b>	<b>6 749</b>	<b>6 840</b>	<b>6 932</b>	<b>7 024</b>	<b>7 115</b>	<b>7 206</b>	<b>7 297</b>
8	<b>Total Exports</b>																	
9	<b>Total Peak Demand</b> 7+8																	
	691	701	712	723	733	744	755	766	777	788	799	810	821	832	843	854	865	876
11	<b>System Surplus</b> 6-9-10																	
12	Less: Brandon Unit 5																	
<b>Exportable Surplus</b> 11+12																		
	345	249	150	48	305	204	104	1	255	152	50	305	203	100	354	252	150	48

Date: November 12, 2013

**System Firm Energy Demand and Dependable Resources (GWh) @ generation**  
**NFAT 2012 Reference**  
**All Combined Cycle Gas**

Fiscal Year	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
<b>Power Resources</b>																		
<b>New Power Resources</b>																		
New Hydro																		
Conawapa																		
Keeyask																		
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Early Morning																		
First Rapids																		
1	<b>Total New Hydro</b>																	
New Thermal																		
SCGT																		
CCGT																		
2	<b>Total New Thermal</b>																	
New Imports																		
Contracted																		
Proposed																		
3	<b>Total New Imports</b>																	
4	New Wind																	
5	<b>Total New Power Resources</b> 1+2+3+4																	
<b>Base Supply Power Resources</b>																		
Existing Hydro																		
Existing Thermal																		
Brandon Coal - Unit 5																		
Selkirk Gas																		
Brandon Units 6-7 SCGT																		
Contracted Imports																		
Proposed Imports																		
Hydro Adjustment																		
Market Purchases																		
Existing Wind																		
Pointe du Bois Rebuild																		
Bipole III Reduced Losses																		
6	<b>Total Base Supply Power Resources</b>																	
7	<b>Total Power Resources</b> 5+6																	
<b>Manitoba Domestic Load</b>																		
2012 Base Load Forecast																		
Construction Power - Hydro																		
Less: 2012 Base DSM Forecast																		
Demand Side Management Aggressive																		
8	<b>Manitoba Net Load</b>																	
Contracted Exports																		
Proposed Exports																		
Less: Adverse Water																		
9	<b>Total Net Exports</b>																	
10	<b>Total Energy Demand</b> 8+9																	
11	<b>System Surplus</b> 7-10																	
12	Less : Brandon Unit 5																	
13	Adverse Water																	
<b>Exportable Surplus</b> 11+12+13																		

Date: November 12, 2013

**System Firm Energy Demand and Dependable Resources (GWh) @ generation**

NFAT 2012 Reference

All Combined Cycle Gas

Fiscal Year		2030/31	2031/32	2032/33	2033/34	2034/35	2035/36	2036/37	2037/38	2038/39	2039/40	2040/41	2041/42	2042/43	2043/44	2044/45	2045/46	2046/47	2047/48
<b>Power Resources</b>																			
<b>New Power Resources</b>																			
	New Hydro																		
	Conawapa																		
	Keeyask																		
	Notigi																		
	Manasan																		
	Early Morning																		
	First Rapids																		
1	<b>Total New Hydro</b>																		
	New Thermal																		
	SCGT																		
	CCGT	8 118	8 118	8 118	8 118	10 824	10 824	10 824	10 824	13 530	13 530	13 530	16 236	16 236	16 236	18 942	18 942	18 942	18 942
2	<b>Total New Thermal</b>	<b>8 118</b>	<b>8 118</b>	<b>8 118</b>	<b>8 118</b>	<b>10 824</b>	<b>10 824</b>	<b>10 824</b>	<b>10 824</b>	<b>13 530</b>	<b>13 530</b>	<b>13 530</b>	<b>16 236</b>	<b>16 236</b>	<b>16 236</b>	<b>18 942</b>	<b>18 942</b>	<b>18 942</b>	<b>18 942</b>
	New Imports																		
	Contracted																		
	Proposed																		
3	<b>Total New Imports</b>																		
4	New Wind																		
5	<b>Total New Power Resources</b>	<b>8 118</b>	<b>8 118</b>	<b>8 118</b>	<b>8 118</b>	<b>10 824</b>	<b>10 824</b>	<b>10 824</b>	<b>10 824</b>	<b>13 530</b>	<b>13 530</b>	<b>13 530</b>	<b>16 236</b>	<b>16 236</b>	<b>16 236</b>	<b>18 942</b>	<b>18 942</b>	<b>18 942</b>	<b>18 942</b>
		1+2+3+4																	
<b>Base Supply Power Resources</b>																			
	Existing Hydro	21780	21780	21 770	21 760	21760	21 750	21 740	21 740	21 730	21 730	21 720	21 710	21 710	21 700	21 690	21 690	21 680	21 670
	Existing Thermal																		
	Brandon Coal - Unit 5																		
	Selkirk Gas	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953
	Brandon Units 6-7 SCGT	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354
	Contracted Imports																		
	Proposed Imports																		
	Hydro Adjustment																		
	Market Purchases	3 068	3 068	3 068	3 068	3 068	3 068	3 068	3 068	3 068	3 068	3 068	3 068	3 068	3 068	3 068	3 068	3 068	3 068
	Existing Wind	777	777	777	777	777	777	777	777	777	777	777	777	777	777	777	777	777	777
	Pointe du Bois Rebuild	60	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150	150
	Bipole III Reduced Losses	239	239	239	239	239	239	239	239	239	239	239	239	239	239	239	239	239	239
6	<b>Total Base Supply Power Resources</b>	<b>29 231</b>	<b>29 321</b>	<b>29 311</b>	<b>29 301</b>	<b>29 301</b>	<b>29 291</b>	<b>29 281</b>	<b>29 281</b>	<b>29 271</b>	<b>29 271</b>	<b>29 261</b>	<b>29 251</b>	<b>29 251</b>	<b>29 241</b>	<b>29 231</b>	<b>29 231</b>	<b>29 221</b>	<b>29 211</b>
7	<b>Total Power Resources</b>	<b>37 349</b>	<b>37 439</b>	<b>37 429</b>	<b>37 419</b>	<b>40 125</b>	<b>40 115</b>	<b>40 105</b>	<b>40 105</b>	<b>42 801</b>	<b>42 801</b>	<b>42 791</b>	<b>45 487</b>	<b>45 487</b>	<b>45 477</b>	<b>48 173</b>	<b>48 173</b>	<b>48 163</b>	<b>48 153</b>
		5+6																	
<b>Manitoba Domestic Load</b>																			
	2012 Base Load Forecast	32 967	33 425	33 882	34 340	34 798	35 255	35 713	36 170	36 628	37 085	37 543	38 001	38 458	38 916	39 373	39 831	40 288	40 746
	Construction Power - Hydro	30	10																
	Less: 2012 Base DSM Forecast	- 816	- 803	- 779	- 743	- 711	- 682	- 657	- 628	- 598	- 568	- 540	- 516	- 487	- 459	- 431	- 404	- 377	- 349
	Demand Side Management Aggressive																		
8	<b>Manitoba Net Load</b>	<b>32 181</b>	<b>32 632</b>	<b>33 103</b>	<b>33 597</b>	<b>34 087</b>	<b>34 573</b>	<b>35 056</b>	<b>35 542</b>	<b>36 030</b>	<b>36 517</b>	<b>37 003</b>	<b>37 485</b>	<b>37 971</b>	<b>38 457</b>	<b>38 942</b>	<b>39 427</b>	<b>39 911</b>	<b>40 397</b>
	Contracted Exports	145	145	145	145	145	145	145	145	145	145	145	145	145	145	145	145	145	145
	Proposed Exports																		
	Less: Adverse Water																		
9	<b>Total Net Exports</b>	<b>145</b>																	
10	<b>Total Energy Demand</b>	<b>32 326</b>	<b>32 777</b>	<b>33 248</b>	<b>33 742</b>	<b>34 232</b>	<b>34 718</b>	<b>35 201</b>	<b>35 687</b>	<b>36 175</b>	<b>36 662</b>	<b>37 148</b>	<b>37 630</b>	<b>38 116</b>	<b>38 602</b>	<b>39 087</b>	<b>39 572</b>	<b>40 056</b>	<b>40 542</b>
		8+9																	
11	<b>System Surplus</b>	<b>5 023</b>	<b>4 662</b>	<b>4 181</b>	<b>3 677</b>	<b>5 893</b>	<b>5 397</b>	<b>4 904</b>	<b>4 418</b>	<b>6 626</b>	<b>6 139</b>	<b>5 643</b>	<b>7 857</b>	<b>7 371</b>	<b>6 875</b>	<b>9 086</b>	<b>8 601</b>	<b>8 107</b>	<b>7 611</b>
	Less : Brandon Unit 5																		
13	Adverse Water																		
	<b>Exportable Surplus</b>	<b>5 023</b>	<b>4 662</b>	<b>4 181</b>	<b>3 677</b>	<b>5 893</b>	<b>5 397</b>	<b>4 904</b>	<b>4 418</b>	<b>6 626</b>	<b>6 139</b>	<b>5 643</b>	<b>7 857</b>	<b>7 371</b>	<b>6 875</b>	<b>9 086</b>	<b>8 601</b>	<b>8 107</b>	<b>7 611</b>
		11+12+13																	

1 **SUBJECT: SPLASH; export Market prices**

2

3 **REFERENCE: Potomac Dependable Sales October 24 presentation provided on**  
4 **SharePoint**

5

6 **PREAMBLE:** This question references documents Manitoba Hydro has labeled as  
7 commercially sensitive information. Please refer to slide 5 of the referenced  
8 presentation.

9

10 **QUESTION:**

11 Please provide the assumed on-peak energy price plus 50% of capacity price used for the  
12 SPLASH modeling runs in the NFAT submission in an electronic spreadsheet.

13

14 **RESPONSE:**

15 The response to this Information Request includes Commercially Sensitive Information and has  
16 been filed in confidence with the Public Utilities Board.

1 **SUBJECT: SPLASH; export Market prices**

2

3 **REFERENCE: Potomac Dependable Sales October 24 presentation provided on**  
4 **SharePoint**

5

6 **PREAMBLE:** This question references documents Manitoba Hydro has labeled as  
7 commercially sensitive information. Please refer to slide 5 of the referenced  
8 presentation.

9

10 **QUESTION:**

11 The response to this Information Request includes Commercially Sensitive Information and has  
12 been filed in confidence with the Public Utilities Board.

1 **SUBJECT: SPLASH; export Market prices**

2

3 **REFERENCE: Potomac Dependable Sales October 24 presentation provided on**  
4 **SharePoint**

5

6 **PREAMBLE:** This question references documents Manitoba Hydro has labeled as  
7 commercially sensitive information. Please refer to slide 5 of the referenced  
8 presentation.

9

10 **QUESTION:**

11 Are there any circumstances where on-peak opportunity sales do not include any capacity  
12 portion but are instead only based on energy prices? If so, please describe these circumstances.

13

14 **RESPONSE:**

15 The response to this Information Request includes Commercially Sensitive Information and has  
16 been filed in confidence with the Public Utilities Board.

1 **SUBJECT: Natural Gas price; Carbon price**

2

3 **REFERENCE: Moment Matching and Probability Distribution Explanation pdf provided**  
4 **on SharePoint**

5

6 **PREAMBLE:** This question references documents Manitoba Hydro has labeled as  
7 commercially sensitive information. Please refer to the Natural Gas and Carbon price  
8 forecasts listed in Table 2.

9

10 **QUESTION:**

11 Are these values in constant or nominal dollars? If constant dollars, from what year?

12

13 **RESPONSE:**

14 The values shown in Table 2 are in constant 2012 dollars.

1 **SUBJECT: Natural Gas price; Carbon price**

2

3 **REFERENCE: Moment Matching and Probability Distribution Explanation pdf provided**  
4 **on SharePoint**

5

6 **PREAMBLE:** This question references documents Manitoba Hydro has labeled as  
7 commercially sensitive information. Please refer to the Natural Gas and Carbon price  
8 forecasts listed in Table 2.

9

10 **QUESTION:**

11 Does the natural gas price forecast reflect a forecast of Henry Hub prices or a delivered price?

12 If a delivered price please define the delivery point.

13

14 **RESPONSE:**

15 The natural gas price forecast in Table 2 reflects a forecast of Henry Hub prices.

1 **SUBJECT: Natural Gas price; Carbon price**

2

3 **REFERENCE: Moment Matching and Probability Distribution Explanation pdf provided**  
4 **on SharePoint**

5

6 **PREAMBLE:** This question references documents Manitoba Hydro has labeled as  
7 commercially sensitive information. Please refer to the Natural Gas and Carbon price  
8 forecasts listed in Table 2.

9

10 **QUESTION:**

11 What Energy Price Outlook was relied upon to create the natural gas price forecast shown in  
12 the table, if any?

13

14 **RESPONSE:**

15 The 2012 Energy Price Outlook was used to create the natural gas price forecast shown in Table  
16 2. The Henry Hub forecasted values provided in the 2012 Energy Price Outlook were escalated  
17 from 2011 constant dollars to 2012 constant dollars using the US GDP Deflator for the  
18 reference scenario documented in Appendix 11.2 of the NFAT submission.

1 **SUBJECT: Natural Gas Price**

2

3 **REFERENCE: Appendix 9.3, Section 1.5.2**

4

5 **QUESTION:**

6 Does the natural gas price entered into SPLASH for use in estimating the production costs of  
7 new CCGT or CT units reflect only Henry Hub prices? If there are any adjustments made to the  
8 Henry Hub forecast, such as a basis differential, please provide the adjustments used for the  
9 natural gas price forecasts relied upon for the NFAT submission with any supporting work  
10 papers in electronic spreadsheet format. Please provide the information separately for the  
11 2012/13 forecast and 2013/14 forecast.

12

13 **RESPONSE:**

14 The natural gas prices used in the SPLASH model to estimate the production cost of a new CCGT  
15 or SCGT in Manitoba is based on forecasted AECO Hub prices delivered from Alberta to Manitoba  
16 and is the same as that used to estimate the production cost of Manitoba Hydro's existing  
17 natural gas-fired units. Please see Manitoba Hydro's response to LCA/MH II-475.

1 **SUBJECT: Natural Gas Price**

2

3 **REFERENCE: Appendix 9.3, Section 1.5.2**

4

5 **QUESTION:**

6 Does Manitoba Hydro prepare any delivered natural gas price forecasts for the MISO market?

7 If so please supply these forecasts from the past two years along with any supporting

8 workpapers in electronic spreadsheet format. Please identify any relied upon for the NFAT

9 submission.

10

11 **RESPONSE:**

12 Manitoba does not prepare any delivered natural gas price forecasts for the MISO market.

1 **SUBJECT: Natural Gas Price**

2

3 **REFERENCE: 2012-13 and 2013-14 Consultant Natural Gas Price Forecasts spreadsheet**  
4 **provided on SharePoint**

5

6 **PREAMBLE:** This question references documents Manitoba Hydro has labeled as  
7 commercially sensitive information. Please refer to the Natural Gas price forecasts.

8

9 **QUESTION:**

10 Please explain how the consultant forecasts, NYMEX or other data was used to calculate the  
11 numbers in the "Forecast-Henry Hub" column?

12

13 **RESPONSE:**

14 The response to this Information Request includes Commercially Sensitive Information and has  
15 been filed in confidence with the Public Utilities Board.

1 **SUBJECT: Natural Gas Price**

2

3 **REFERENCE: 2012-13 and 2013-14 Consultant Natural Gas Price Forecasts spreadsheet**  
4 **provided on SharePoint**

5

6 **PREAMBLE:** This question references documents Manitoba Hydro has labeled as  
7 commercially sensitive information. Please refer to the Natural Gas price forecasts.

8

9 **QUESTION:**

10 Please provide the source and dates for the numbers in the NYMEX and EIA columns.

11

12 **RESPONSE:**

13 The response to this Information Request includes Commercially Sensitive Information and has  
14 been filed in confidence with the Public Utilities Board.

1 **SUBJECT: Natural Gas Price**

2

3 **REFERENCE: 2012-13 and 2013-14 Consultant Natural Gas Price Forecasts spreadsheet**  
4 **and Gas Turbine Operating Cost Inputs pdf both provided on SharePoint**

5

6 **PREAMBLE:** This question references documents Manitoba Hydro has labeled as  
7 commercially sensitive information. Please refer to the Natural Gas price forecasts in  
8 the spreadsheet and the Natural Gas Price forecasts on page 4 of the pdf.

9

10 **QUESTION:**

11 Please explain how the reference, high, and low natural gas price forecasts on page 4 of the  
12 referenced pdf relate to the forecasts in the spreadsheet?

13

14 **RESPONSE:**

15 The response to this Information Request includes Commercially Sensitive Information and has  
16 been filed in confidence with the Public Utilities Board.

1 **SUBJECT: Natural Gas Price**

2

3 **REFERENCE: Gas Turbine Operating Cost Inputs pdf provided on SharePoint**

4

5 **PREAMBLE:** This question references documents Manitoba Hydro has labeled as  
6 commercially sensitive information. Please refer to the Natural Gas price forecasts on  
7 page 4 of the pdf.

8

9 **QUESTION:**

10 Please provide the assumed transportation charges for the natural gas price forecasts listed in  
11 the pdf.

12

13 **RESPONSE:**

14 Please see Manitoba Hydro's response to LCA/MH II-475 which was filed in confidence with the  
15 PUB.

1 **SUBJECT: Export Contracts; Export Market Policies**

2

3 **REFERENCE: 2012 08 Wholesale Export Policy pdf provided on SharePoint, p. 1**

4

5 **PREAMBLE:** This question references documents Manitoba Hydro has labeled as  
6 commercially sensitive information.

7

8 **QUESTION:**

9 Please provide a copy of the "Import & Export of Power - Approval Authority for Wholesale  
10 Power Related Transactions".

11

12 **RESPONSE:**

13 The response to this Information Request includes Commercially Sensitive Information and has  
14 been filed in confidence with the Public Utilities Board.

1 **SUBJECT: Export Contracts; Export Market Policies**

2

3 **REFERENCE: 2012 08 Wholesale Export Policy pdf provided on SharePoint, p. 2**

4

5 **PREAMBLE:** This question references documents Manitoba Hydro has labeled as  
6 commercially sensitive information.

7

8 **QUESTION:**

9 Please provide an example of the operational risk "arising from carrying out Manitoba Hydro's  
10 business functions with respect to wholesale power related transactions".

11

12 **RESPONSE:**

13 Manitoba Hydro defines operational risk as the risk of loss resulting from inadequate or failed  
14 internal processes, people and systems, or from external events.

15

16 An example of the operational risk "arising from carrying out Manitoba Hydro's business  
17 functions with respect to the wholesale power related transactions" is described below:

18

19 Manitoba Hydro regularly sells energy on a forward bilateral basis. In order to minimize  
20 exposure to operational risk, Manitoba Hydro's power trader must seek approval of sales  
21 quantities prior to execution. In this case the operational risk would be the risk of over  
22 committing Manitoba Hydro to energy sales.

1 **SUBJECT: Export Contracts; Export Market Policies**

2

3 **REFERENCE: 2012 08 Wholesale Export Policy pdf provided on SharePoint, p. 2**

4

5 **PREAMBLE:** This question references documents Manitoba Hydro has labeled as  
6 commercially sensitive information.

7

8 **QUESTION:**

9 Please provide an example of how the export contracts that are part of the Preferred  
10 Development Plan were approved with "a risk governance and executive oversight structure".  
11 What controls, measurement and reporting were used?

12

13 **RESPONSE:**

14 The following risk governance and executive oversight process was used for the Minnesota  
15 Power 250 MW Power Sales Agreement .

16

17 In 2006 discussions with Minnesota Power and Manitoba Hydro commenced on the possibility  
18 of a long-term surplus energy and capacity sale. In February 2007, Minnesota Power (MP)  
19 issued a RFP for up to 200 MW for 30 years, to which Manitoba Hydro submitted a proposal.  
20 Based upon that proposal and subsequent discussions with MP a Term Sheet was prepared by  
21 the Export Power Marketing Department. The Term Sheet was drafted in accordance with  
22 Manitoba Hydro's Management Control Plan which had been approved by The Manitoba  
23 Hydro-Electric Board in 2007. An Executive Committee recommendation was presented and  
24 approved at the December 4, 2007 meeting.

25

26 In accordance with the Approved Signing Authority Table in place at the time, the Term Sheet  
27 was signed by the Division Manager of Power Sales and Operations on December 12, 2007.

1 With the signing of the Term Sheet, drafting of a Power Sales Agreement commenced.  
2 Manitoba Hydro's negotiating team included a lead negotiator, who reported directly to the  
3 Division Manager of Power Sales and Operations, contract administrative staff and analysts  
4 from the Export Power Marketing Department, and internal and external legal advisors.

5 The final agreements were locked down February 28, 2011 at which point internal reviews were  
6 completed by the following:

- 7 • Market Access and Regulatory Affairs, Export Power Marketing – Review contract  
8 provisions related to market access and regulatory requirements;
- 9 • Transmission Access, Export Power Marketing – Review provisions related to  
10 transmission requirements;
- 11 • Contract Administration and Credit - Review counterparty credit worthiness;
- 12 • Export Operations Department – Review provisions for operating requirements;
- 13 • Energy Policy Officer - Review provisions related to claims on environmental attributes  
14 (e.g. Renewable Energy Credits (RECs), Emissions);
- 15 • Resource Planning and Market Analysis conducted an independent review and analysis  
16 of the sale and provided a favourable recommendation to the Vice President of Power  
17 Supply.

18

19 A recommendation to execute the 250 MW MP Power Sale Agreement and 250 MW Energy  
20 Exchange Agreement was made to the Executive Committee and then to The Manitoba Hydro-  
21 Electric Board. Following Board approval the Agreement was signed by Manitoba Hydro.

1 **SUBJECT: Export Contracts; Export Market Policies**

2

3 **REFERENCE: 2012 08 Wholesale Export Policy pdf provided on SharePoint, p. 2**

4

5 **PREAMBLE:** This question references documents Manitoba Hydro has labeled as  
6 commercially sensitive information.

7

8 **QUESTION:**

9 Please provide a recent example of the records of transactions in Manitoba Hydro's deal  
10 capture system.

11

12 **RESPONSE:**

13 The response to this Information Request includes Commercially Sensitive Information and has  
14 been filed in confidence with the Public Utilities Board.

1 **SUBJECT: Export Contracts; Export Market Policies**

2

3 **REFERENCE: 2012 08 Wholesale Export Policy pdf provided on SharePoint, p. 2**

4

5 **PREAMBLE:** This question references documents Manitoba Hydro has labeled as  
6 commercially sensitive information.

7

8 **QUESTION:**

9 How frequently does the President and CEO of Manitoba Hydro report policy violations to the  
10 Chairman of the Board?

11

12 **RESPONSE:**

13 The President and CEO of Manitoba is required to notify the Chairman of the Board of any  
14 policy violations as soon as reasonably possible. A report summarizing the violation is provided  
15 for review at the next scheduled Board meeting. To date there have been very few policy  
16 violations reported.

17

18 Exceptions to policy are handled differently. Exceptions to policy are immediately reported to  
19 the Vice President of Generation Operations and are reported at and recorded in the minutes  
20 of the next EPRMC (Export Power Risk Management Committee) meeting. Should this  
21 exceptional circumstance be expected to become the norm, the Wholesale Export Power Policy  
22 is revised accordingly.

1 **SUBJECT: Drought Impacts; Climate Change**

2

3 **REFERENCE: LCA/MH I-121**

4

5 **PREAMBLE:** The climate change sensitivity offers no analysis of the potential change in  
6 likelihood of a drought worse than the worst drought on record because (a) only  
7 average change in streamflow was used from GCMs, without analyzing potential  
8 volatility in annual streamflow estimates; and (b) historic drought years in the long term  
9 flow data were assumed not to change.

10

11 **QUESTION:**

12 Has Manitoba Hydro analyzed the potential impact of climate change on the probability of  
13 experiencing a drought worse than the worst drought on record in the long term flow data? If  
14 so, please describe the results and conclusions. If not, please explain why such an analysis has  
15 not been conducted.

16

17 **RESPONSE:**

18 Manitoba Hydro has not specifically analyzed the potential impact of climate change on the  
19 probability of experiencing a drought worse than the worst drought on record in the long-term  
20 flow data. However, Manitoba Hydro has given consideration to the probability of drought.  
21 There are a number of references to the probability of the current drought on record which can  
22 be found in the Kubursi-Magee report, "*Manitoba Hydro Risks: An Independent Review*"  
23 *submitted to the Public Utilities Board in the 2010 Risk hearing*. A link to the redacted version of  
24 this report was provided to La Capra in November 2013 at [http://www.pub.gov.mb.ca/exhibits-](http://www.pub.gov.mb.ca/exhibits-6.html)  
25 [6.html](http://www.pub.gov.mb.ca/exhibits-6.html) .

26

27 In Chapter 4 of the Kubursi-Magee report (*Water Flows: Statistical Modeling, Prediction of*  
28 *Droughts, and other Issues*) and Chapter 7 (*Conclusions*), reference is made to statistical  
29 analysis that was done independently and concluded that the worst drought on record (actual

1 minimum) fell within the expected range of the probability distribution, as noted in the  
2 reference extracted from Chapter 4.7, page 162:

3 *“We find that the actual minimum lies roughly in the middle of our 95% intervals, and the*  
4 *means and medians of our simulated minima are greater than the actual minimum. On the one*  
5 *hand, this reassures us that the use of the actual minimum as a kind of benchmark worst-*  
6 *possible-case scenario is not unduly optimistic or pessimistic. On the other hand, because we*  
7 *find that the 95% intervals are fairly wide, we wish to caution that an over-reliance on the*  
8 *actual minimum could result in a mind-set in which it is not necessary to consider the possibility*  
9 *of even worse outcomes, or indeed more beneficial water flow conditions”.*

10

11 Due to the rare occurrence of extreme events, the limited record of historic climate and  
12 climate model biases, it is difficult to assess the performance of the climate model’s ability to  
13 simulate past extreme events. These limitations are particularly relevant to extreme drought  
14 events, which can be influenced by decadal and multi-decadal signals in hydroclimatic  
15 variability. Global Climate Models (GCMs) are more adept at reproducing average climatic  
16 conditions and less adept in simulating extreme events. The ability of GCMs to simulate average  
17 climatic conditions better than extremes is not surprising, since GCMs operate on a coarse  
18 spatial resolution and do not capture smaller-scale features that can influence extremes.  
19 Currently there is a high level of uncertainty on the magnitude of impacts to future extremes.  
20 As stated in Chapter 10 page 43 of the NFAT Business Case, “Manitoba Hydro is working with  
21 Ouranos, several universities and other utilities to investigate downscaling and post-treatment  
22 methods to quantify local impacts to extreme events and climatic variability. These studies are  
23 currently on-going.”

24

25 As a result, Manitoba Hydro has not conducted a probabilistic analysis of climate change  
26 impacts on more extreme drought events. Manitoba Hydro recognizes that there are views that  
27 more extreme floods and droughts could occur in a changing climate; however, at this point  
28 there is no quantitative evidence to support these views.

- 1 Please see Manitoba Hydro's response to MNP/MH I-072 for additional discussion related to
- 2 the risks of extreme events.

1 **SUBJECT: Transmission Economics**

2

3 **REFERENCE: Integrated Transmission Plan for Keeyask and Conawapa Generation SPD**  
4 **2011/11**

5

6 **PREAMBLE:** This question references documents Manitoba Hydro has labeled as  
7 confidential.

8

9 **QUESTION:**

10 Is the north/south project included in the NFAT the same as option 2A described in the  
11 Integrated Transmission Plan for Keeyask and Conawapa generation report? If yes, confirm that  
12 up to 122 MW of non-firm transmission has been included in the economic cash flows/SPLASH  
13 runs?

14

15 **RESPONSE:**

16 The incremental north/south transmission that is included in the NFAT for development plans  
17 that include both Keeyask and Conawapa is as described in option 2A. It is assumed that  
18 normal operating conditions would have 2 of the 3 switchable Kettle units placed on NCS1 and  
19 1 unit would be placed on NCS2, resulting in only 105 MW of non-firm transmission. The  
20 configuration of the switchable units would be varied to accommodate equipment  
21 maintenance conditions.

22

23 It is not confirmed that up to 122 MW of non-firm transmission has been included in the  
24 economic cash flows/SPLASH runs, however 105 MW of non-firm transmission was included.  
25 The cost of the Option 2A was included in the economic analysis. It is expected that opportunity  
26 sales can be made using non-firm transmission.

1 **SUBJECT: Transmission Economics**

2

3 **REFERENCE: Integrated Transmission Plan for Keeyask and Conawapa Generation SPD**  
4 **2011/12**

5

6 **PREAMBLE:** This question references documents Manitoba Hydro has labeled as  
7 confidential.

8

9 **QUESTION:**

10 Please provide detailed cost estimates for the capital costs of Option 2A (Table 12 in the  
11 document). Provide all assumptions, workpapers, and data sources used. Where possible,  
12 please provide workpapers and data in electronic spreadsheet format with all formulas intact  
13 and readable.

14

15 **RESPONSE:**

16 The response to this Information Request includes Commercially Sensitive Information and has  
17 been filed in confidence with the Public Utilities Board.

1 **SUBJECT: Transmission Economics**

2

3 **REFERENCE: Integrated Transmission Plan for Keeyask and Conawapa Generation SPD**  
4 **2011/13**

5

6 **PREAMBLE:** This question references documents Manitoba Hydro has labeled as  
7 confidential.

8

9 **QUESTION:**

10 Please provide detailed costs estimates for capital costs of Option 1 (Table 2 in the document)

11 Provide all assumptions, workpapers, and data sources used. Where possible, please provide

12 workpapers and data in electronic spreadsheet format with all formulas intact and readable.

13

14 **RESPONSE:**

15 The response to this Information Request includes Commercially Sensitive Information and has

16 been filed in confidence with the Public Utilities Board.

1 **SUBJECT: Transmission Economics**

2

3 **REFERENCE: Final Interconnection Evaluation Study Report for Keeyask Hydropower**  
4 **Limited Partnership NRIS for Keeyask Generating Station (650, 695 or, 800 MW June**  
5 **2012)**

6

7 **PREAMBLE:** This question references documents Manitoba Hydro has labled as  
8 confidential.

9

10 **QUESTION:**

11 Is Option 2- Keeyask 695 MW NRIS included in the NFAT? If yes, is the assumption that requires  
12 Kettle to relinquish 65 MW factored in the SPLASH runs/economic cash flows?

13

14 **RESPONSE:**

15 The effect of the Keeyask G.S. rating on the Kettle G.S. is factored into the SPLASH runs and  
16 economic analysis. The assumptions for the net system firm capacity addition in the NFAT  
17 analysis at Keeyask is 630 MW. It is noted in the Manitoba Hydro 2011/12 Power Resource  
18 Plan (Section 5, page 21) included as Appendix B of the NFAT Business Case, that the winter  
19 peak prating for Keeyask is 630 MW and at this output level the capacity at other plants is not  
20 affected.

21

22 The energy levels assumed in the SPLASH runs are consistent with a 630 MW capacity  
23 assumption at Keeyask<sup>i</sup>. The SPLASH model assumes that Stephens Lake is at the average  
24 elevation for each month, and that the capacity of both Keeyask and Kettle is adjusted to reflect  
25 the assumed Stephens Lake elevation. The combined capacity of Kettle and Keeyask is equal to  
26 or less than 1854 MW (ranging from about 1840 MW to 1854 MW).

- 1 The Interconnection Facilities Study request for Keeyask identifies 630 MW of Network
- 2 Resource Interconnection Service, and 65 MW of Energy Resource Interconnection Service.
- 3 This request is published on the Manitoba Hydro Open Access site as part the Transmission
- 4 Tarrif, and can be found at:
- 5 ([http://www.oasis.oati.com/woa/docs/MHEB/MHEBdocs/MHEB\\_Gen\\_Q\\_Status\\_Report\\_Oct\\_3](http://www.oasis.oati.com/woa/docs/MHEB/MHEBdocs/MHEB_Gen_Q_Status_Report_Oct_3)
- 6 [1\\_2013.pdf](http://www.oasis.oati.com/woa/docs/MHEB/MHEBdocs/MHEB_Gen_Q_Status_Report_Oct_3))

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<sup>i</sup> The rating of Keeyask is noted in Table 2.1 of Chapter 2 of the NFAT Business Case. Assuming Stephens Lake is 141.12 m, the rated output of Keeyask is 630 MW and Kettle is 1224 MW. If Stephens Lake is at a low level of 139.60 m the output of Keeyask increases to 695 MW, while the output of Kettle reduces to 1150 MW.

1 **SUBJECT: Transmission Economics**

2

3 **REFERENCE: Final Interconnection Evaluation Study Report for Keeyask Hydropower**  
4 **Limited Partnership NRIS for Keeyask Generating Station (650, 695 or, 800 MW June 8**  
5 **2012)**

6

7 **PREAMBLE:** This question references documents Manitoba Hydro has labeled as  
8 confidential.

9

10 **QUESTION:**

11 Is Option 2- Keeyask 695 MW NRIS included in the NFAT? If yes, is the assumption that requires  
12 Kettle to relinquish 65 MW factored in the SPLASH runs/economic cash flows?

13

14 **RESPONSE:**

15 The rating of Keeyask is noted in Table 2.1 of Chapter 2. Assuming Stephens Lake is 141.12 m,  
16 the rated output is 630 MW and if Stephens Lake is at a low level of 139.6 m the rated output of  
17 Keeyask is 695 MW. The assumptions for net system firm capacity addition in NFAT at Keeyask  
18 is 630 MW. Chapter 5 of the Manitoba Power Resource Plan (Appendix B) also notes that winter  
19 peak rating for Keeyask is 630 MW and at this output level the capacity at other plants is not  
20 affected. The energy levels assumed in the Splash runs are consistent with a 630 MW capacity  
21 assumption at Keeyask. The SPLASH model assumes that Stephens Lake is at the average  
22 elevation for each month, and both Keeyask and Kettle capacity is adjusted to reflect the  
23 assumed Stephens Lake elevation. The combined Kettle and Keeyask capacity is equal to or less  
24 than 1854 MW (ranging from about 1820 to 1854 MW), so the effect of Keeyask rating on  
25 Kettle is factored on the SPLASH runs.

1 **SUBJECT: Transmission Economics**

2

3 **REFERENCE: Final Interconnection Evaluation Study Report for Keeyask Hydropower**  
4 **Limited Partnership NRIS for Keeyask Generating Station (650, 695 or, 800 MW June 8**  
5 **2012)**

6

7 **PREAMBLE:** This question references documents Manitoba Hydro has labeled as  
8 confidential.

9

10 **QUESTION:**

11 Is the estimated cost for Option 2 network upgrades included in the economic cash flows for all  
12 the plans that include Keeyask?

13

14 **RESPONSE:**

15 Yes, the estimated cost for Option 2 network upgrades to interconnect Keeyask to the northern  
16 collector system, were included in the economic cash flows for all plans that include Keeyask. It  
17 is noted that the cost for Option 1 (650 MW) is the same as the cost for Option 2 (695 MW).

1 **SUBJECT: Transmission Economics**

2

3 **REFERENCE: MHEM 1100/750/250 MW Export/Import Firm Point to Point Group**  
4 **Transmission service requests**

5

6 **PREAMBLE:** This question references documents Manitoba Hydro has labeled as  
7 confidential.

8

9 **QUESTION:**

10 Is the Y500 option similar to the option utilized in the preferred plan? If not, describe any  
11 differences.

12

13 **RESPONSE:**

14 Option Y500 in the referenced report “Group Facilities Study MHEM 1100/750/250 MW  
15 Export/Import Firm Group TSR” is virtually identical to the 500 kV 750 MW tie line referenced in  
16 the preferred plan in the NFAT submission. The only minor difference is that an additional  
17 series phase shifter at Glenboro is recommended to be included with Y500 in the latest report  
18 compared with the preferred plan submission assumptions. The cost difference is roughly \$12  
19 million.

1 **SUBJECT: Transmission Economics**

2

3 **REFERENCE: MHEM 1100/750/250 MW Export/Import Firm Point to Point Group**  
4 **Transmission service requests**

5

6 **PREAMBLE:** This question references documents Manitoba Hydro has labeled as  
7 confidential.

8

9 **QUESTION:**

10 Table ES1 shows a summary of all the network upgrades needed for the Y500 option. Are the  
11 network upgrade costs included in the NFAT analysis?

12

13 **RESPONSE:**

14 Table ES1 in the referenced report included a summary of both additional Network Upgrades  
15 needed in Manitoba on top of the new tie line Network Upgrade as well as third party impacts.  
16 The first two items in the list: G82R phase shifting transformer and HVdc reduction scheme are  
17 Manitoba Network Upgrades. The phase shifter cost was included in the estimate. The dc  
18 reduction scheme additions were not included as the complete scope of work was not defined  
19 at the time the report was issued. It is expected that the dc reduction scheme cost would be of  
20 an amount which could be assumed to be included in the estimate contingency.

21

22 The remainder of the items are third party impacts in the MISO network and the no estimate  
23 was determined. . Manitoba Hydro is in the process of coordinating with MISO to determine if  
24 the identified third party upgrades are valid and should be included in MISO's report and final  
25 Facility Construction Agreement.

1 **SUBJECT: Transmission Economics**

2

3 **REFERENCE: MHEM 1100/750/250 MW Export/Import Firm Point to Point Group**  
4 **Transmission service requests**

5

6 **PREAMBLE:** This question references documents Manitoba Hydro has labeled as  
7 confidential.

8

9 **QUESTION:**

10 The report states "North Dakota export and Minnesota- Wisconsin export increases negatively  
11 affect the flow on the new 500 kV line". How is Manitoba Hydro accounting for this finding in its  
12 NFAT analysis?

13

14 **RESPONSE:**

15 The reference is found on Page 6 of the referenced report, "Increase in North Dakota Export  
16 (NDEX) and Minnesota-Wisconsin Export (MWEX) negatively affects the flow on the Riel –  
17 Forbes 500 kV for the Fargo injection. At the maximum simultaneous transfer simulated in this  
18 study (NDEX=2200 MW, MWEX=1600 MW), the North Dakota-Manitoba loop flow issue results  
19 in approximately 105% pre-contingency overload on the Riel – Forbes 500 kV line. This pre-  
20 contingency overload can be mitigated by controlling the power flow distributions on the US-  
21 MH interface through a phase shifting transformer added on to 230 kV line G82R." The issue  
22 identified in the report was mitigated by controlling the setpoint on the proposed phase shifter  
23 on G82R to 200-250 MW south.

24

25 However, the issue was identified for the competing plan terminating in the Fargo area. This  
26 issue did not arise in the preferred plan where the tie line terminates at Blackberry. The phase  
27 shifter at Glenboro could be used for controlling congestion in the export direction if needed,  
28 however it was justified in the preferred plan because it eliminated overloads on the 230 kV

- 1 line G82R during import conditions. The preferred plan in NFAT includes the cost of a phase
- 2 shifting transformer at Glenboro.

1 **SUBJECT: Transmission Economics**

2

3 **REFERENCE: MHEM 1100/750/250 MW Export/Import Firm Point to Point Group**  
4 **Transmission service requests**

5

6 **PREAMBLE:** This question references documents Manitoba Hydro has labeled as  
7 confidential.

8

9 **QUESTION:**

10 One of the upgrades needed for the Y500 option is a new HVDC power order reduction scheme.  
11 Please provide documentation of this and estimated cost. (See Table 12 Comments section for  
12 the new 500 kV tie line contingency.)

13

14 **RESPONSE:**

15 Manitoba Hydro has an existing HVdc power order reduction scheme that includes inputs from  
16 all of its tie lines. The assumption is the new tie line would add new inputs into the existing  
17 HVdc reduction scheme. The referenced report has identified a minimum of two new inputs  
18 would be required: loss of the new 500 kV line between Dorsey and Blackberry as well as the  
19 Blackberry 500/230 kV transformer. It is likely that bypassing of the new series capacitor bank  
20 at Blackberry will also require detection and a dc reduction but this was not verified.

21

22 An estimate for the additional dc reduction input signals was not prepared or included in the  
23 cost of upgrades. Based on past experience, it is expected that these upgrades will be relatively  
24 modest depending on available communication capacity and controller capacity at Dorsey. An  
25 estimate is being prepared and will be included in the final version of the Group Facility Study  
26 report.

1 **SUBJECT: Transmission Economics**

2

3 **REFERENCE: MHEM 1100/750/250 MW Export/Import Firm Point to Point Group**  
4 **Transmission service requests**

5

6 **PREAMBLE:** This question references documents Manitoba Hydro has labeled as  
7 confidential.

8

9 **QUESTION:**

10 The incremental impact of the TSRs included in this report is evaluated with the VSAT  
11 application. How does VSAT determine the output of different generators (Manitoba and U.S.)  
12 in the study?

13

14 **RESPONSE:**

15 VSAT is a tool developed by PowerTech that is similar to Siemen's PSS/E in terms of the network  
16 solution calculation method. With VSAT, transactions (e.g. Manitoba to U.S.) can be  
17 programmed to occur automatically in steps. The activity identifies a study system in which  
18 generation is increased (or load is decreased) and an opposing system in which generation is  
19 decreased (or load is increased). Manitoba Hydro used the same POR and POD sources and  
20 sinks as MISO did in their studies. For each 50 MW step in transfer level, appropriate generation  
21 is adjusted in each control area based on the aggregate of the 1100 MW in TSRs. For example,  
22 250/1100 or 22.7% of the 50 MW step will result in generation in the MP control area being  
23 adjusted.

1 **SUBJECT: Transmission Economics**

2

3 **REFERENCE: LCA/MH I-152, LCA/MH I-153, LCA/MH I-154, LCA/MH I-155, LCA/MH I-**  
4 **156**

5 **PREAMBLE:** This question references documents Manitoba Hydro has labeled as  
6 confidential.

7

8 **QUESTION:**

9 Provide all assumptions, workpapers, and data sources used in forming the referenced  
10 responses. In the reports provided by Manitoba Hydro, it is mentioned that the costs are  
11 estimated (+/- 50%). How is this calculated? Where possible, please provide workpapers and  
12 data in electronic spreadsheet format with all formulas intact and readable.

13

14 **RESPONSE:**

15 Ac Transmission lines and station estimates reflect a linear project and rely on Manitoba Hydro standard  
16 estimating approaches with cross-checks of recently completed projects. A different methodology  
17 applies to the HVdc component cost as they are non-standard custom designs and cost  
18 estimates have been developed based on a combination of equipment manufacturers'  
19 budgetary prices and Manitoba Hydro past experience.

20

21 Various estimate levels would occur for a project depending on the project stages. The costs provided  
22 for North-south transmission system upgrade project, Keeyask transmission project, Conawapa  
23 transmission project and the Manitoba Hydro-U.S. tie line projects refer to Manitoba Hydro level 1  
24 estimate. This is a high-level base estimate in the Planning stage that typically relies on unit cost  
25 information based on the best information available on the project, historic numbers, evaluation of  
26 costs from comparable projects undertaken by other utilities, as well as consideration of market  
27 conditions. The estimate assumes +/-50% accuracy with no contingency . With the further refinement  
28 of project details and the progress of project, the accuracy of estimate levels will increase and falls into  
29 level 2 (+/-30%) or level 3 level (+/-10%).. A certain project may have mixed estimate levels for various

1 components depending on the different project stages for such component. In such a case, the lowest  
2 estimate level is used for the project.

3 The typical unit costs are summarized in the exploratory study, “Interconnection of 400 MW of  
4 Future Generation to the Northern AC System” completed in 2009 (filed as a reference report in  
5 response to LCA/MH-II-494). The unit cost of the 230kV line cost has been increased to  
6 300k/km (> 10km) and the cost of the 500kV ac single circuit overhead line was estimated at  
7 800k/km considering the cost increase experienced recently.

1 **SUBJECT: Transmission Economics**

2

3 **REFERENCE: LCA/MH I-147**

4

5 **PREAMBLE:** This question references documents Manitoba Hydro has labeled as  
6 confidential.

7

8 **QUESTION:**

9 In the answer provided for LCA-147, Manitoba Hydro states that the transfer limits may be  
10 different from the firm transfer capability limits provided in the NFAT. Provide the 5 lowest  
11 Manitoba Hydro-U.S. transfer limits and the reason for the reduction.

12

13 **RESPONSE:**

14 The long term firm transfer capability in the planning horizon during system intact conditions is  
15 2175 MW south and 700 MW north. These limits include a 75 MW reliability margin and a 150  
16 MW reserve sharing obligation to MISO in the southern direction. Therefore, long term firm  
17 transmission service requests would typically be limited to 625 MW in the north direction and  
18 1950 MW in the southern direction.

19

20 Seasonal operating studies represent the transfer capability that can be specified during specific  
21 operating conditions expected for that season. The seasonal capability may be equal to or  
22 greater than the expected long term firm capability during system intact conditions. Long  
23 duration outages can impact shorter term transfer capability (eg. daily, weekly, monthly).

24 The top five outages and the associated Manitoba to US transfer limits are:

25 1. Dorsey to Forbes 500 kV line – 675 MW

26 2. Forbes to Chicago 500 kV line – 675 MW

27 3. Roseau series capacitors – 1875 MW

- 1 4. Dorsey 500/230 kV transformer – 1875 MW
- 2 5. Forbes SVC – 2080 MW
- 3 The real time performance of the interface has been very good. The export availability during
- 4 the peak and off-peak summer hours (May-September) is typically better than 95%. Scheduled
- 5 outages of the 500 kV line for maintenance occur in spring and fall for a few days or few weeks
- 6 at most each year.

1 **SUBJECT: MISO; Opportunity Exports**

2

3 **PREAMBLE:** Regarding opportunity imports to the MISO market.

4

5 **QUESTION:**

6 Please describe how Manitoba Hydro uses MISO markets to import power.

7

8 **RESPONSE:**

9 Manitoba Hydro has the ability to purchase power from the MISO market to serve load in  
10 Manitoba on a day ahead and real time basis. Purchases are made when the price of purchased  
11 power is economic relative to Manitoba Hydro's alternative supply sources.

12

13 On a day-ahead basis, Manitoba Hydro is able to submit a bid to purchase power at a specified  
14 price signifying the maximum Manitoba Hydro is willing to pay for each hour of the following  
15 day. Manitoba Hydro's purchase price is determined based on its value of water in storage.  
16 Once the MISO market clears, Manitoba is notified of the energy quantity it has purchased and  
17 the Manitoba Hydro Electric Board market clearing price for each respective hour. On a real  
18 time basis, Manitoba Hydro is able to submit a bid to purchase power but is unable to indicate a  
19 maximum purchase price. MISO will charge the real time Manitoba Hydro Electric Board  
20 market clearing price to all power purchased in real time.

1 **SUBJECT: MISO; Opportunity Exports**

2

3 **PREAMBLE:** Regarding opportunity imports to the MISO market.

4

5 **QUESTION:**

6 As an external asynchronous resource, does Manitoba Hydro import using the DA and RT  
7 markets? Why or why not?

8

9 **RESPONSE:**

10 Currently MISO only allows external asynchronous resources to sell into the MISO market.

11 Importing from MISO using an external asynchronous resource is not permitted at this time.

1 **SUBJECT: MISO; Opportunity Exports**

2

3 **PREAMBLE:** Regarding opportunity exports to the MISO market.

4

5 **QUESTION:**

6 Please describe how Manitoba Hydro uses MISO markets to export power.

7

8 **RESPONSE:**

9 Manitoba Hydro has the ability to sell energy to the MISO market on a day ahead and real time  
10 basis. On a day-ahead basis, Manitoba Hydro is able to submit an offer to sell power at a  
11 specified price signifying the minimum price Manitoba Hydro is willing to sell at for each hour of  
12 the following day. Manitoba Hydro's offer price is based on its value of water in storage plus a  
13 small risk premium. Once the MISO market clears, Manitoba is notified of the energy quantity  
14 it has sold and the MHEB market clearing price for each respective hour. On a real time basis,  
15 Manitoba Hydro is able to submit an offer to sell power but is unable to indicate a minimum  
16 sale price. MISO will pay the real time MHEB market clearing price for all power sold in real  
17 time.

1 **SUBJECT: MISO; Opportunity Exports**

2

3 **PREAMBLE:** Regarding opportunity exports to the MISO market.

4

5 **QUESTION:**

6 As an external asynchronous resource, does Manitoba Hydro export using the DA and RT  
7 markets? Why or why not?

8

9 **RESPONSE:**

10 Yes, Manitoba Hydro has the ability to export a portion of its surplus power to MISO on a DA  
11 and RT basis as an external asynchronous resource (EAR). Manitoba Hydro uses EAR to offer  
12 power as well as three ancillary service products (regulation, spinning reserves, and  
13 supplemental reserves) to the MISO market. An advantage to offering energy on the EAR in RT  
14 is that EAR provides a limited amount of RT price protection as Manitoba Hydro is permitted to  
15 submit a minimum offer price for power and ancillary services sold under the EAR. There is no  
16 price protection for energy offered to the RT market using MISO's standard export offer  
17 mechanisms.

1 **SUBJECT: MISO; Opportunity Exports**

2

3 **PREAMBLE:** Regarding opportunity exports to the MISO market.

4

5 **QUESTION:**

6 Does Manitoba Hydro offer power at cost or at zero price in MISO? If at cost, how does  
7 Manitoba Hydro bid non-zero amounts without market-based rate authority? If the conditions  
8 under which Manitoba Hydro makes non-zero offers varies, please explain the conditions  
9 Manitoba Hydro makes non-zero offers into MISO.

10

11 **RESPONSE:**

12 Manitoba Hydro offers its power to MISO based upon its marginal costs. Manitoba Hydro does  
13 not require U.S. Federal Energy Regulatory Commission market based rate authority to sell  
14 energy to the MISO market as the sale does not occur in the U.S. but rather title to the energy  
15 transfers to MISO at the Canada-U.S. border.