MIPUG/MH II-1

Subject: IFRS

a) Given the recent decision by the Financial Reporting & Assurance Standards Canada Accounting Standards Board (AcSB) to extend the existing deferral of the mandatory IFRS changeover date for entities with qualifying rate-regulated activities by an additional year to January 1, 2014, does Manitoba Hydro expect to defer IFRS changeover by a year?

ANSWER:

Yes, Manitoba Hydro expects to defer implementation of IFRS by one year to fiscal 2014/15.

MIPUG/MH II-2

Subject: MIPUG/MH I-2(a), IFF12

a) Please confirm that IFF11 (filed March 30, 2012) includes a rate increase sequence that includes 3.5% as of April 1, 2012 and a further 3.5% as of April 1, 2013.

ANSWER:

Confirmed.

MIPUG/MH II-2

Subject: MIPUG/MH I-2(a), IFF12

b) Please confirm that IFF11-2 (filed June 15, 2012) includes a rate increase sequence that includes 2.0% April 1, 2012, a further 2.5% September 1, 2012 and a further 3.5% as of April 1, 2013.

ANSWER:

Confirmed.

<u>MIPUG/MH II-2</u>

Subject: MIPUG/MH I-2(a), IFF12

c) Please indicate if Manitoba Hydro intends to file IFF12 as evidence in the current hearing, assuming its approval by the MH Board in November 2012?

<u>ANSWER</u>:

Manitoba Hydro expects that IFF12 will be presented to the Manitoba Hydro-Electric Board (MHEB) in November 2012. Manitoba Hydro will file IFF12 with the PUB and Intervenors subsequent to its approval by the MHEB.

MIPUG/MH II-2

Subject: MIPUG/MH I-2(a), IFF12

d) Please indicate if IFF12 is expected to include different assumptions regarding the April 1, 2013 rate increase? If so, is it expected that this would further change Hydro's requested approvals in the current application?

ANSWER:

Please see Manitoba Hydro's response to PUB/MH II-37(a).

<u>MIPUG/MH II-3</u>

Subject: MIPUG/MH I-4(a), Wuskwatim

a) Please confirm that at page 34 of Attachment 3 of the July 20, 2012 Interim Rates filing (the 2011/12 Power Resource Plan), the value of dependable energy from Wuskwatim in 2018/19 is 1250 GW.h.

<u>ANSWER</u>:

Manitoba Hydro confirms that for the year 2018/19 of the 2011/12 Power Resource Plan the amount of dependable energy available from Wuskwatim is 1250 GWh.

MIPUG/MH II-3

Subject: MIPUG/MH I-4(a), Wuskwatim

b) Please confirm that at page 34 of Attachment 3 of the July 20, 2012 Interim Rates filing (the 2011/12 Power Resource Plan), the dependable energy system surplus is 1666 GW.h

ANSWER:

Manitoba Hydro confirms that for the 2018/19 year of Attachment 3, the 2011/12 Power Resource Plan, the dependable energy system surplus is 1666 GW.h.

MIPUG/MH II-3

Subject: MIPUG/MH I-4(a), Wuskwatim

c) Based on the answers to (a) and (b) above, please confirm that, absent Wuskwatim, in 2018/19, the system surplus would remain positive.

ANSWER:

While a simple subtraction of the Wuskwatim energy of 1250 GWh from the total system surplus of 1666 GWh yields a positive result, there are other factors to consider as stated in Manitoba Hydro's response to MIPUG/MH I-4(a).

The two tables below depict certain components of supply and demand in the Power Resource Plans from 2004/05 to 2011/12 for two particular load years 2011/12 and 2019/20. The tables show the increases in total commitments as a result of increases in Manitoba load growth starting with the 2005/06 Power Resource Plan and the subsequent decline in Manitoba load growth starting with the 2009/10 Power Resource Plan. The tables also show the quantities assumed from a planning perspective for wind generation and for Wuskwatim generation.

As stated in MIPUG/MH I-4(a), in the 2011/12 Power Resource Plan, the 250 MW of wind power that has been purchased under Power Purchase Agreements has deferred the need for new energy sources to meet Manitoba load to 2020/21. Deducting both Wuskwatim and wind generation from system surplus gives a representative indication of when new generation resources would have been required. The tables below show that in all Power Resource Plans from 2006/07 to 2011/12 new generation resources would have been required for the 2012/13 and 2019/20 load years. Wuskwatim as the next generation resource would fulfill this requirement, while wind power defers the need for new energy resources.

Power Resource Plan
No New Generation (GW.h)

2012/13 Load Year								
Power Resource Plan	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
MB Load	24,988	25,592	26,497	26,932	27,127	25,793	25,142	25,173
Total Commitments	27,927	28,531	29,665	30,191	30,386	29,042	28,507	28,374
Wuskwatim	1,250	1,250	878	878	1,250	1,250	1,250	1,205
Wind	717	820	1,311	1,069	1,069	1,254	783	819
Total	1,967	2,070	2,189	1,947	2,319	2,504	2,033	2,024
System Surplus	3,088	2,316	1,294	654	702	2,156	1,888	1,826
- Wind	2,371	1,496	(17)	(415)	(367)	902	1,105	1,007
- Wind & Wuskwatim	1,121	246	(895)	(1,293)	(1,617)	(348)	(145)	(198)

2019/20 Load Year								
Power Resource Plan	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12
MB Load	26368	26928	28275	29264	29295	28452	28016	27966
Total Commitments	26513	27073	28420	29409	31502	29409	29658	29607
Wuskwatim	1250	1250	1250	1250	1250	1250	1250	1250
Wind	717	820	1311	1229	1229	1254	783	819
Total	1967	2070	2561	2479	2479	2504	2033	2069
System Surplus	2417	2361	1517	365	(154)	785	470	406
- Wind	1700	1541	206	(864)	(1383)	(469)	(313)	(413)
- Wind & Wuskwatim	450	291	(1044)	(2114)	(2633)	(1719)	(1563)	(1663)

In addition, please see Manitoba Hydro’s response to MIPUG/MH II-16(b) which shows that, based on the 2011/12 Power Resource Plan Page 34 of Attachment 3 and deducting both Wuskwatim and wind generation from system surplus, a persistent deficit occurs starting in the first year of the plan which is 2011/12.

MIPUG/MH II-3

Subject: MIPUG/MH I-4(a), Wuskwatim

d) Comparable to the analysis in parts (a) through (c) of this information request, please confirm that at page 36 of the same document, that absent Wuskwatim in 2018/19 the system firm winter peak demand would remain in system surplus condition.

ANSWER:

Manitoba Hydro confirms that for the 2018/19 year of the 2011/12 Power Resource Plan absent Wuskwatim the system winter peak surplus remains positive. As a predominantly hydro-electric system Manitoba Hydro expects that energy resources would be required in advance of capacity resources.

MIPUG/MH II-3

Subject: MIPUG/MH I-4(a), Wuskwatim

e) Given the responses to (a) through (d) of this information request, please indicate in detail why the response to MIPUG/MH-1-4(a) is "not confirmed".

ANSWER:

Please see Manitoba Hydro's responses to MIPUG/MH II-3(c) and (d).

MIPUG/MH II-4

Subject: MIPUG/MH I-6(b), Rates in Other Jurisdictions

a) Given Manitoba Hydro was aware of Newfoundland PUB Order P.U.6-2012, which approved a new rate for Vale Newfoundland and Labrador Limited equal to the rate that has long been charged to Teck mine in Newfoundland ($6.68/kW/month and an energy rate of 1.676 cents/kW.h, a rate approximately 40% below the current Manitoba Hydro rates), and this new rate supersedes the January 1, 2012 Newfoundland Hydro rate schedules, why is this information not included in Manitoba Hydro's comparison of what customers face as to rates in other jurisdictions in Appendix 10.10?

ANSWER:

Manitoba Hydro's annual Survey of Canadian Electricity Bills does not identify or specify particular rate schedules for the participating utility respondents. Rather it identifies load characteristics for the benchmark loads and the participating utilities calculate the bill in the survey.

In the case of large industrial customers, Manitoba Hydro requests that the participating utilities provide the monthly bill, excluding taxes, for customers with unity power factor, customer owned transformation and service at Transmission voltage exceeding 100 kV for three levels of monthly usage: 20 MVA and 12 million kWh; 50 MVA and 31 million kWh and 100 MVA and 62 million kWh. The amounts shown for Newfoundland and Labrador Hydro in the 2012 survey were provided by Newfoundland and Labrador Hydro.

MIPUG/MH II-5

Subject: MIPUG/MH I-7(a), Marginal Value

a) **For each annual change in the marginal value, please indicate the amount of the change (in cents/kW.h) driven by annual changes to the Weighted Average Cost of Capital, versus to other factors.**

ANSWER:

Power Smart Plan	Levelized Marginal Value (cents/kWh)	Original Discount Rate Used	Levelized Marginal Value using Previous Year's Discount Rate (cents/kWh)	Change in Levelized Marginal Value Compared to Previous Year (Assuming Previous Year Discount Rate) (cents/kWh)	Change in Marginal Value due to Change in Discount Rate (cents/kWh)
2011	8.52	6.10%	8.56	(0.39)	(0.04)
2010	8.95	5.75%	8.93	0.68	0.02
2009	8.26	6.00%	8.25	0.16	0.01
2008	8.08	6.10%	8.08	0.27	0.00
2007	7.81	6.10%	7.82	(0.12)	(0.00)
2006	7.93	6.00%	7.93	0.13	0.00
2005	7.80	6.00%	7.80	0.24	(0.00)
2004	7.56	5.98%	7.55	0.26	0.01
2003	7.29	6.08%	7.30	0.31	(0.01)
2002	6.99	5.93%	6.99	0.23	0.00
2001	6.76	5.93%	N/A	N/A	N/A

MIPUG/MH II-6

Subject: MIPUG/MH I-7(d), Bioenergy

a) In assessing the DSM benefits associated with the Bioenergy program, please indicate the future time horizon assumed for generation benefits due to customer-installed bioenergy generation.

ANSWER:

Time periods used for determination of the net present value of demand side management benefits associated with customer-owned bioenergy generation are dependent on the anticipated life of the measure, potential for reinvestment at end-of-life, and related contractual agreements for specific projects.

In instances where the anticipated life of the measure and potential for reinvestment are unknown or unpredictable, time periods used for analysis are based on contractual agreements specifying the duration of the period over which the customer is obligated to supply energy.

MIPUG/MH II-6

Subject: MIPUG/MH I-7(d), Bioenergy

b) Please file a copy of Manitoba Hydro's non-utility generation guideline. Please indicate if there have been any changes to this guideline in the last three years, or if any further changes are planned.

ANSWER:

Manitoba Hydro's Open Access Interconnection Tariff (2012 03 16), Distributed Resource Interconnection Procedures (2005 06 30) and Technical Requirements for Connecting Distributed Resources (Rev 2.1, 2011 01) can be found in Appendix 37, along with the following link to Manitoba Hydro's Open Access Transmission Tariff and associated documents (http://oasis.midwestiso.org/OASIS/MHEB).

No substantive changes were made to these documents in the last three years.

MIPUG/MH II-7

Subject: MIPUG/MH I-8(a), Export Contracts

a) The question requested an updated version of the information attached to RCM/TREE-MH-1-27 from the 2010 GRA. The response refers the question to CAC/MH-1-115(a) which does not provide the same information as RCM/TREE-MH-1-27 from the 2010 GRA. Please provide an updated version of the attachment to RCM/TREE-MH-1-27, showing all comparable information and data to the original attachment.

ANSWER:

The document provided in response to RCM/TREE-MH-I-27 in the 2010 GRA was prepared specifically for ICF as part of their review of Manitoba Hydro's Export Power Sales and Associated Risks. The document was referenced in ICF's report filed in that process and RCM/TREE had requested Manitoba Hydro produce the referenced document. In order to file to the requested information it was necessary to redact the document as it contained confidential information that is commercially sensitive. Manitoba Hydro declines to update this document in the same format in the current proceeding as filed in the 2010 GRA. Such request would by necessity require that Manitoba Hydro prepare the update and then immediately redact it prior to filing.

CAC/MH I-115(a) provides a summary of Manitoba Hydro's current firm export contracts and Table 1 and 2 on pages 5 and 6 of Tab 9, Volume II of Manitoba Hydro's Application provide the total energy and capacity commitments associated with the contracts.

MIPUG/MH II-8

Subject: MIPUG/MH I-12(a), PUB/MH II-45(a) from the 2011 GRA

a) As requested in MIPUG/MH I-12(a), please provide and update to PUB/MH II-45(a) from the 2010 GRA which extends out 20 years (versus the 10 years that were provided in CAC/MH I-3(a)).

ANSWER:

Please see the attached schedules.

AVERAGE PRICE CALCULATION: IFF11-2

VOLUMES (in GW.h)	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
Demand:										
Manitoba Domestic Energy Sales	21749	22261	22488	22523	22796	23173	23351	23728	24119	24468
Domestic energy Losses	3161	3181	3223	3237	3272	3022	3061	3100	3138	3166
Firm & Opportunity Export Sales to Canada	915	589	577	603	595	581	570	537	471	559
Firm & Opportunity Export Sales to US	6337	6537	6378	6257	6048	5853	5673	5845	7713	8396
Export Transmission Losses	625	654	632	624	600	575	554	555	736	819
Total Demand Volumes:	**32787**	**33222**	**33299**	**33244**	**33311**	**33204**	**33209**	**33767**	**36177**	**37409**
Supply:										
MH Hydraulic Generation	29268	30744	30712	30693	30699	30461	30375	30813	33223	34591
MH Thermal Generation	111	311	328	314	332	385	430	295	307	298
Purchased Energy	3497	2259	2350	2328	2371	2449	2495	2751	2738	2612
Total Supply Volumes:	**32876**	**33313**	**33390**	**33335**	**33402**	**33296**	**33300**	**33858**	**36268**	**37500**

REVENUE/COST (in millions of dollars)	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
Manitoba Domestic Energy Sales @ Approved Rates	1,290.384	1,293.566	1,306.475	1,313.103	1,329.744	1,349.664	1,361.356	1,381.890	1,402.571	1,421.635
Additional Domestic Revenue	45.260	105.523	156.033	208.272	264.834	325.447	387.404	455.377	527.459	603.097
Total Manitoba Domestic Energy Sales	1,335.644	1,399.089	1,462.508	1,521.375	1,594.578	1,675.111	1,748.760	1,837.267	1,930.030	2,024.732
Total Export Sales to Canada	33.720	25.704	30.824	37.390	41.398	44.821	47.780	48.654	46.621	54.997
Total Export Sales to USA	221.081	277.149	320.013	386.869	415.481	439.948	458.828	513.945	725.031	808.434
Total Export Sales	254.801	302.852	350.838	424.259	456.879	484.769	506.608	562.599	771.652	863.431
MH Hydraulic Generation	97.834	102.715	102.608	102.546	102.564	101.771	101.482	102.945	110.999	115.572
MH Thermal Generation	9.386	21.929	25.643	25.530	28.061	34.026	40.391	36.076	38.836	39.123
Purchased Energy	120.044	108.483	120.490	125.566	133.687	143.093	151.183	167.962	171.345	170.701

AVERAGE PRICE ($/MW.h))	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
Manitoba Domestic Energy Sales @ Approved Rates	$ 59.33	$ 58.11	$ 58.10	$ 58.30	$ 58.33	$ 58.24	$ 58.30	$ 58.24	$ 58.15	$ 58.10
Additional Domestic Revenue	2.08	4.74	6.94	9.25	11.62	14.04	16.59	19.19	21.87	24.65
Total Manitoba Domestic Energy Sales @ meter	61.41	62.85	65.04	67.55	69.95	72.29	74.89	77.43	80.02	82.75
Total Export Sales to Canada	36.85	43.66	53.39	62.03	69.62	77.14	83.81	90.54	98.93	98.43
Total Export Sales to USA	34.89	42.40	50.17	61.83	68.70	75.17	80.88	87.92	94.00	96.29
Total Export Sales	35.14	42.50	50.44	61.85	68.78	75.34	81.14	88.14	94.29	96.42
MH Hydraulic Generation	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34
MH Thermal Generation	84.56	70.61	78.22	81.42	84.54	88.28	93.91	122.44	126.61	131.32
Purchased Energy	34.33	48.03	51.26	53.93	56.37	58.43	60.59	61.06	62.58	65.36

AVERAGE PRICE CALCULATION: IFF11-2

VOLUMES (in GW.h)	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31
Demand:									
Manitoba Domestic Energy Sales	24814	25161	25510	25865	26266	26648	27026	27392	27760
Domestic energy Losses	3237	3302	3342	3487	3525	3579	3629	3688	3732
Firm & Opportunity Export Sales to Canada	555	538	386	553	689	663	651	632	633
Firm & Opportunity Export Sales to US	8264	8188	9296	12179	12978	12692	12343	12048	11885
Export Transmission Losses	804	775	887	1194	1279	1242	1202	1167	1149
Total Demand Volumes:	**37674**	**37964**	**39420**	**43277**	**44736**	**44823**	**44852**	**44927**	**45160**
Supply:									
MH Hydraulic Generation	34813	34685	36500	40442	41715	41670	41637	41638	41837
MH Thermal Generation	305	324	299	251	262	278	275	276	276
Purchased Energy	2647	3045	2712	2675	2850	2965	3031	3104	3139
Total Supply Volumes:	**37765**	**38055**	**39511**	**43368**	**44827**	**44914**	**44943**	**45018**	**45251**
REVENUE/COST (in millions of dollars)									
Manitoba Domestic Energy Sales @ Approved Rates	1,440.557	1,459.652	1,478.804	1,498.358	1,520.624	1,541.314	1,561.748	1,581.673	1,601.558
Additional Domestic Revenue	682.933	767.293	822.484	879.993	941.345	1,004.062	1,068.956	1,135.879	1,205.194
Total Manitoba Domestic Energy Sales	2,123.490	2,226.945	2,301.288	2,378.351	2,461.969	2,545.376	2,630.704	2,717.552	2,806.752
Total Export Sales to Canada	57.003	57.101	47.325	62.910	76.069	75.887	77.396	77.846	80.783
Total Export Sales to USA	822.968	837.452	1,023.829	1,290.968	1,394.691	1,411.875	1,404.792	1,408.400	1,424.775
Total Export Sales	879.971	894.552	1,071.153	1,353.878	1,470.761	1,487.762	1,482.188	1,486.246	1,505.557
MH Hydraulic Generation	116.313	115.886	121.946	135.118	139.370	139.220	139.108	139.113	139.776
MH Thermal Generation	41.425	45.594	43.612	38.365	41.181	45.084	45.980	47.736	49.235
Purchased Energy	179.710	206.998	188.473	190.629	208.679	222.634	233.009	244.857	253.887
AVERAGE PRICE ($/MW.h))									
Manitoba Domestic Energy Sales @ Approved Rates	$ 58.06	$ 58.01	$ 57.97	$ 57.93	$ 57.89	$ 57.84	$ 57.79	$ 57.74	$ 57.69
Additional Domestic Revenue	27.52	30.50	32.24	34.02	35.84	37.68	39.55	41.47	43.41
Total Manitoba Domestic Energy Sales @ meter	85.58	88.51	90.21	91.95	93.73	95.52	97.34	99.21	101.11
Total Export Sales to Canada	102.66	106.17	122.49	113.84	110.43	114.54	118.87	123.17	127.58
Total Export Sales to USA	99.59	102.28	110.14	106.00	107.47	111.24	113.81	116.90	119.88
Total Export Sales	99.78	102.52	110.63	106.34	107.62	111.41	114.06	117.21	120.27
MH Hydraulic Generation	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34
MH Thermal Generation	135.82	140.72	145.81	153.02	157.18	161.91	167.37	172.79	178.45
Purchased Energy	67.89	67.97	69.50	71.28	73.21	75.08	76.87	78.89	80.89

MIPUG/MH II-9

Subject: MIPUG/MH I-15(a), Gannett Fleming

a) The question asked for all studies performed by Gannett Fleming (not solely Mr. Kennedy, if there is a difference). Please indicate if there are additional studies performed by Gannett Fleming in Canada over the same period which were not directed by Mr. Larry Kennedy, and provide a comparable list.

ANSWER:

The following response was prepared by Gannett Fleming.

Two additional studies have been completed and filed in Canada by Gannett Fleming analysts other than Mr. Kennedy as follows:

1) Nova Scotia Power – Completed by Mr. John Wiedmayer from the firm's Valley Forge office in 2010. This study was entered as evidence but was part of a negotiated settlement and therefore an appearance before the Nova Scotia Public Utilities Board was not required.

2) Newfoundland Power – Completed by Mr. John Wiedmayer from the firm's Valley Forge office in 2012. This study has just recently been filed and the regulatory review process has not yet started.

MIPUG/MH II-9

Subject: MIPUG/MH I-15(a), Gannett Fleming

b) Please clarify which of the utilities listed in the attachment to MIPUG/MH-1-15(a) and in response to part (a) of this question are Crown utilities.

ANSWER:

The following response was prepared by Gannett Fleming.

The following utilities are either Crown Corporations or city owned utilities:

- Northwest Territories Power Corporation
- Manitoba Hydro
- Yukon Energy Corporation
- The City of Red Deer Electric system
- British Columbia Transmission Corporation
- BC Hydro
- City of Lethbridge Electric System
- SaskPower
- Quilliq Energy Corporation

MIPUG/MH II-9

Subject: MIPUG/MH I-15(a), Gannett Fleming

c) For each study in part (b) above, please indicate if the study is:

i. intended to be compliant with IFRS;
ii. makes use of the ASL procedure, the ELG procedure, or some other procedure (please specify);
iii. includes net salvage in the depreciation rates or some other form of amortization over the useful life of the asset in question.

ANSWER:

The following response was prepared by Gannett Fleming.

Northwest Territories Power Corporation (NWTPC) – 2012 Study

i. Study was prepared giving consideration to IFRS implementation issues
ii. Study was prepared using the ASL procedure
iii. Study includes net salvage within the depreciation calculations

Manitoba Hydro – 2010 Study

i. Study was prepared giving consideration to IFRS implementation issues
ii. Study was prepared using the ELG procedure
iii. Study does not include net salvage within the depreciation calculations.

Yukon Energy Corporation – 2004 Study

i. Study was prepared prior to IFRS
ii. Study was prepared using the ASL procedure
iii. Study includes net salvage within the depreciation calculations

The City of Red Deer Electric system – 2011 Study

i. Study was not prepared giving consideration to IFRS
ii. Study was prepared using the ELG procedure
iii. Study includes net salvage within the depreciation calculations

British Columbia Transmission Corporation – 2005 Study

i. Study was prepared prior to IFRS
ii. Study was prepared using the ASL procedure
iii. Study does not include net salvage within the depreciation calculations

BC Hydro – 2006 Study

i. Study was prepared prior to IFRS
ii. Study was prepared using the ASL procedure
iii. Study does not include net salvage within the depreciation calculations

City of Lethbridge Electric System – 2008 Study

i. Study was not prepared giving consideration to IFRS
ii. Study was prepared using the ELG procedure
iii. Study includes net salvage within the depreciation calculations

SaskPower – 2011 Study

i. Current study was prepared giving consideration to IFRS implementation issues
ii. Study was prepared using the ASL procedure
iii. Study does not include net salvage within the depreciation calculations.

Quilliq Energy Corporation – 2011 Study

i. Study was not prepared giving consideration to IFRS
ii. Study was prepared using the ASL procedure
iii. Study does not include net salvage within the depreciation calculations

MIPUG/MH II-10

Subject: **Re: CAC/MH-I-47(a), Equal Life Group**

Preamble: **The response indicates "The ELG method will minimize the amount of gains and losses recognized on retirement of assets, and will reduce net income volatility".**

a) **Please provide evidence, with reference to the actual experience of MH over the past 10 years using an ASL system, of the net income volatility that would have arisen had IAS16 part 68 (requirement to immediately recognize gains and losses) been applied. Specifically, please provide a summary of Manitoba Hydro's net income using ASL under GAAP, and what Manitoba Hydro's net income would have been using ASL under IAS 16 part 68 been in force.**

ANSWER:

The requested information is not available. Under CGAAP, Manitoba Hydro follows the common utility practice of using group accounting for assets, whereby retirement transactions are recorded in the financial records as a credit to asset cost and a debit to accumulated depreciation. As such, it is only necessary to track accumulated depreciation at the depreciable component level for compliance with CGAAP. In order to calculate the gains and losses actually experienced in a particular year, it would be necessary to have a system in place to track accumulated depreciation separately for each install year applicable to each depreciable component.

For the time period requested, Manitoba Hydro's asset accounting records do not contain sufficient accumulated depreciation detail to support the calculation of annual gains and losses. This situation is common across the utility industry, which makes it impractical for affected utilities to retrospectively adopt IFRS changes pertaining to Property, Plant & Equipment. The IASB has approved an exemption for rate-regulated entities to carry forward existing PP&E balances as of the date of transition to IFRS.

MIPUG/MH II-10

Subject: **Re: CAC/MH-I-47(a), Equal Life Group**

Preamble: **The response indicates "The ELG method will minimize the amount of gains and losses recognized on retirement of assets, and will reduce net income volatility".**

b) Please indicate numerically the scale of net income volatility and the expected benefits to customers as a percentage of the net income volatility that arises for Manitoba Hydro in relation to water flow variation? Would the net income volatility be less than, equal to, or larger than the water flow volatility that is presently managed through the income statement?

ANSWER:

As described in the response to MIPUG/MH II-10(a), Manitoba Hydro follows the common utility practice of holding gains and losses on disposition of assets within accumulated depreciation (with the assumption that, overall, assets are fully depreciated when retired and the charge against accumulated depreciation offsets the amount accumulated in that account). As historical data with respect to net gains and losses is not available, it is not possible to quantify the potential range of impact that gains or losses calculated under the ASL method of depreciation would have on net income.

Manitoba Hydro expects some level of interim retirement activity, as is evidenced by the assignment of IOWA curves to the components for depreciation purposes. Under the ASL procedure for group depreciation, losses are expected for assets retired prior to the assigned average service life of a given component, which will be offset in later years by gains on assets which survive longer than the average service life. Given the size and age of Manitoba Hydro's asset base, in the short-term, annual losses are more likely to be realized than gains, and there is the potential that these losses could materially and negatively impact net income.

Under the ELG procedure for group depreciation, interim retirement activity is anticipated and is factored into the calculation of depreciation rates. Gains and losses will still occur as the actual timing of retirements is unlikely to exactly match that anticipated. However, with the ELG procedure, gains are no more or less likely to be realized than losses, and it is expected that for any given year, in normal circumstances, gains and losses will be largely offsetting.

MIPUG/MH II-11

Subject: MIPUG/MH I-15(q), Depreciation

a) Re: Attachment 1 – please provide all calculations required to arrive at the values in columns (3) and (5). If these values are derived from other values on the table, please provide all calculations required to arrive at those underlying values.

ANSWER:

The following response was prepared by Gannett Fleming.

The values for each installation vintage as indicated in columns (3) and (5) are based on the age of the installation vintage expressed as a percentage of the age to the average life estimate. The specific values for each age interval were originally published in 1942 in the publication “Depreciation of Group Properties – Engineering Research Institute Bulletin 155 by Robley Winfrey, Iowa State University, Engineering Research Institute, Ames, Iowa. Please refer to the attached excerpt from Bulletin 155. It should be noted that the Equal Life Group procedure was originally known as the Unit Summation procedure. As such the relevant discussion in the provided excerpt is the discussion related to the Unit Summation procedure.

DEPRECIATION OF GROUP PROPERTIES

By Robley Winfrey

ENGINEERING RESEARCH INSTITUTE
BULLETIN 155
1942

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ENGINEERING RESEARCH INSTITUTE
AMES, IOWA 50010

unit properties apply without question. Cases 2 and 3 introduce the problem of more than one life to be handled on a group basis. The derivation of the depreciation equations does not consider such cases.

Case 2 involves (1) an average life for the group of units which is constant for all ages throughout the life of the group, (2) an average life expectancy of the units surviving in the group which decreases as this common age increases (the expectancy equals average life at zero age and zero at the age of the last survivor), and (3) a decreasing number of units in service which varies from 100 percent at zero age to 0 percent at maximum age.

If case 3 is considered to be a continuous property composed of like units and operated always without increase or decrease in number of service units, renewals soon cause the units to be of different ages ranging from zero to maximum age. For purposes of analysis it is considered that renewal units maintain the constant average life and retirement law of the original group of units.

In analyzing these three cases the following fundamental relationships are used:

1. Age+expectancy=probable life.
2. Depreciated (or present) value+depreciation reserve account balance=value new of property surviving in service.
3. Depreciated value+depreciation reserve account balance+value new of retirements=value new of all original units installed.
4. Salvage value=zero (to simplify calculations).

Factors and Formulas for Measuring Depreciation

In setting up ratios expressing the present value or accrued depreciation for each of the three property classes, four service factors are available: (1) age, (2) expectancy, (3) probable life, and (4) average life. For one property unit there is no average life so only three factors can be considered. Of these, probable life is chosen as the service base since it measures total service. The only two possible ratios of service are:

$$A.\ \frac{\text{Age}}{\text{Probable life}}, \qquad \text{and } B.\ \frac{\text{Expectancy}}{\text{Probable life}}.$$

The first ratio is a measure of expired service and the second of remaining or future service. Since age+expectancy=probable life, the following expressions may be written:

$$\frac{\text{Remaining service}}{\text{Total life service}} = 1 - \frac{\text{Age}}{\text{Probable life}} = \frac{\text{Expectancy}}{\text{Probable life}}.$$

This ratio, multiplied by 100, may be regarded as the *service condition percent* of the property unit, that is, the condition percent of the unit based upon units of service rather than upon depreciable value as condition percent was previously defined. The service condition percent is identical with condition percent based upon depreciable value when the straight-line method is used. As shown by Eq. 24, when $r=0$,

$$\frac{(1+r)^n - (1+r)^x}{(1+r)^n - 1} = \frac{n-x}{n}$$

This indicates that for *one unit of property* there is only one possible ratio of service factors that may be used to express present value.

The original group of case 2 offers more possibilities since average life must be considered in addition to the other three factors. The ratios of expired and remaining service may be written:

$$A.\ \frac{\text{Age}}{\text{Probable life}},\quad B.\ \frac{\text{Expectancy}}{\text{Probable life}},\quad \text{and } C.\ \frac{\text{Expectancy}}{\text{Average life}}.$$

A ratio of age to average life cannot be used because at ages above those equal to average life the ratio exceeds unity. As before, A and B are equal if A is subtracted from unity. The expression C, however, is another measure of remaining value unlike that obtained from A or B and is considered in later analyses.

The same fundamental ratios may be applied to continuous properties of case 3, when proper consideration is given to the differences in ages of the units.

For a given case the ratios A and B may each vary when applied to a group of units of like age, depending upon whether the probable life of the average survivor at a given age or the average of the probable lives of the survivors is used. In the first case the survivors are incorrectly considered as one unit, while in the latter case each surviving unit is correctly considered separately and each given its proper weight. The same is true of ratio C for the expectancy.

When considering groups of units instead of single units of property it is necessary to consider ratios B and C (ratio A may be reduced to ratio B) and two possible selections of the probable life (or expectancy). For a group of units of same age, three solutions exist:

1. The *average-life procedure* from ratio C, wherein the service base is chosen as the average life m of the group, and the variable factor which measures the remaining service is the average expectancy of the group.

2. The *probable-life procedure* from ratio B, wherein the probable life n is chosen as that for the average survivor of the group.

3. The *unit-summation procedure* from ratio B, wherein the probable life n is determined for each unit (or for the retirements of each age-interval), and the condition percent is then calculated for each retirement frequency group to find the weighted condition percent of the survivors.

The average-life procedure (1) results in the condition percent of the survivors measured in terms of the average life of the original group, rather than the probable lives of the survivors. The probable-life procedure (2) results in the condition percent of the average survivor which really is equivalent to considering all survivors as one unit. The unit-summation procedure (3), the only mathematically correct procedure, results in the average of the condition percents of the survivors because it considers separately each surviving unit.

Equations for the condition percent of the survivors of an original group for these three procedures are:

Average-life procedure,

$$C_x = 100 \frac{(1+r)^m - (1+r)^{m-e}}{(1+r)^m - 1} \qquad [54]$$

Probable-life procedure,

$$C_x = 100 \frac{(1+r)^L - (1+r)^x}{(1+r)^L - 1} \qquad [55]$$

Unit-summation procedure,

$$C_x = \frac{\sum_x^M 100 \frac{(1+r)^n - (1+r)^x}{(1+r)^n - 1} (f)}{\sum_x^M f = P} \qquad (56)$$

C_x = condition percent of survivors at age x.
r = rate of return, or rate of interest, expressed as a decimal.
m = average life of original group, years.
e = average expectancy of survivors at age x, years.
x = age of group (all survivors of same age), years.
L = average probable life of survivors (probable life of the average survivor) at age x, years.
n = probable life in years of a given unit at age x; each unit has its own probable life.
M = maximum life in years of group = age of last survivor.
f = frequency, or units retired during each 1-year-age interval.
P_x = survivors at age x.

The three equations above are special adaptations of the general quation,

$$C_p = 100 \frac{(1+r)^n - (1+r)^x}{(1+r)^n - 1}, \qquad [22]$$

derived for a single unit, in which n and x can have only one interpretation. When units are considered in groups, Eqs. 54, 55, and 56 may be used, although correct results are obtained only with Eq. 56.

The analysis on pages 21-27 shows that the straight-line assumption, the sinking-fund assumption, and the present-worth principle result in the same calculated present value and accrued depreciation except for difference in interest rate. In their application, however, there generally is a difference in the arithmetical procedure of calculating depreciation. Annual depreciation by the straight-line method usually is found by multiplying the depreciation base by the depreciation rate. In the sinking-fund method the annual depreciation is found by multiplying the depreciation base by the annuity rate and adding the sinking-fund interest accrual for the year. Annual depreciation by the present-worth method usually is obtained as the difference in the present value of the property at the beginning and end of the year. This procedure also is applicable to the other two methods, especially when condition-percent tables are available.

Illustrations of Depreciation Calculations

The three types of properties (one property unit, original group, and continuous property group), the four methods of estimating depreciation (constant percentage of diminishing base, straight line, sinking fund, and present worth), and the three variations of age-life ratios (Eqs. 54, 55, and 56) are illustrated by tables, complete with calculations. These tables are divided into the following groups:

	Table No
1. One unit of property.	
a. Depreciation not a function of interest but a constant percentage of the depreciated value.	14
b. Depreciation not a function of interest but a constant percentage of the depreciable value new.	15
c. Depreciation a function of interest and based upon the sinking-fund assumption.	16, 17
d. Depreciation a function of interest and based upon age, probable life, and the present worth of the probable operation returns.	18
2. Original group of units decreasing to zero in service.	
a. Depreciation not a function of interest, but a constant percentage of the depreciated value.	19, 20
b. Depreciation not a function of interest, but a constant percentage of the depreciable value new of original group.	21, 22
bb. Depreciation not a function of interest, but a constant percentage of the depreciable value new of the average number of survivors.	23
c. Depreciation not a function of interest and based upon ratios of age, average life, and probable life.	24, 25, 26
d. Depreciation a function of interest and based upon the sinking-fund assumption.	27, 28
e. Depreciation a function of interest and based upon ratios of age, average life, and probable life.	29, 30, 31

MIPUG/MH II-11

Subject: MIPUG/MH I-15(q), Depreciation

b) Re: Attachment 3 – please provide all calculations required to arrive at the values in columns (4), (5) and (6). If these values are derived from other values on the table, please provide all calculations required to arrive at those underlying values.

ANSWER:

The following response was prepared by Gannett Fleming.

Column (4) – Allocated Book Reserve – the total amount of allocated book reserve is determined from the company's actual financial sub-ledgers. The total amount by account is allocated to each vintage based on the calculated accrued depreciation amount for each vintage as a percentage of the total account calculated accrued depreciation. For example the Allocated booked reserve for the installation year of 1991 is determined as follows:

($23,525,912/$56,703,974)*$49,241,598

Where the $49,241,598 is based on a known amount from the company's accumulated depreciation sub-ledger.

Column (5) – Future Book Accruals – is determined by subtracting the allocated booked reserve (column 4) from the original cost (column 2). For example the future book accruals for the 1991 installation year are determined as follows:

$80,430,469 - $20,429,847

Column (6) – Remaining Life – The remaining life for each installation vintage as indicated in column (6) is based on the age of the installation vintage expressed as a percentage of the age to the average life estimate. The specific values for each age interval were originally published in 1935 in the publication "Statistical Analysis of Industrial Property Retirements – Engineering Research Institute Bulletin 152 by Robley Winfrey, Iowa State University, Engineering Research Institute, Ames, Iowa. Please refer to the attached excerpt from Bulletin 125. It should be noted that account 1175D is subject to an expected retirement year, and as such, the formulae provided in the attached excerpt have been modified to reflect the truncation of the Iowa curve as at the end of the year 2131.

Statistical Analyses of Industrial Property Retirements

by

Robley Winfrey

IOWA STATE UNIVERSITY FOUNDED 1858

BULLETIN 125
REVISED

ENGINEERING RESEARCH INSTITUTE
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VI. APPENDIX A

EQUATIONS AND CALCULATIONS FOR THE 18 TYPE CURVES

The following section contains supplementary information on the 18 type curves—valuable either in theoretical analyses or in the calculation of the condition percent of industrial property groups. The final equations of the type frequency curves (page 99) give the numerical values of the coefficients and constants in the general equations below. In Table 21 (page 102) is tabulated the percent surviving and probable lives corresponding to the 18 type curves. Table 22 (page 107) gives the total renewals in percent for the type curves.

General Equations for the 18 Type Frequency Curves

LEFT-MODAL NOS. 0 AND 1

$$y_x = y_o \left(1 - \frac{(x \pm d_m)^2}{a^2}\right)^m \quad \text{For } x \text{ values to left of mode}$$

$$y_x = y_o \left(1 - \frac{(x \pm D_m)^2}{A^2}\right)^M \quad \text{For } x \text{ values to right of mode}$$

LEFT-MODAL NOS. 2, 3, 4, AND 5 AND
RIGHT-MODAL NOS. 1, 2, 3, 4, AND 5

$$y_x = Y_e\left(1 + \frac{x \pm D_m}{A_1}\right)^{M_1} \left(1 - \frac{x \pm D_m}{A_2}\right)^{M_2} + y_e\left(1 + \frac{x \pm d_m}{a_1}\right)^{m_1} \left(1 - \frac{x \pm d_m}{a_2}\right)^{m_2}$$

SYMMETRICAL NOS. 0, 1, 2, 3, 4, 5, AND 6

$$y_x = y_o \left(1 - \frac{x^2}{a^2}\right)^m$$

in which y_x = ordinate to the frequency curve at age x (origin at the mean age).

y_o = ordinate to the frequency curve at its mode.

Y_e = ordinate to the major constituent curve at its mean.

y_e = ordinate to the minor constituent curve at its mean.

x = age (in units equal to 10 percent of average life), measured from the average-life ordinate.

D_m, d_m = x distance from the mean of the type curve to the mean of the constituent curve.

$A, A_1, A_2, a, a_1, a_2, M, M_1, M_2, m, m_1, m_2$ are parameters.

Final Equations of the 18 Type Frequency Curves

In the following 18 equations, x is measured from the mean, or average life, negative values of x being to the left of 100 percent of average life and positive values to the right. An age-interval of 10 percent of average life is equal to x. Therefore, if $x = -2.5$ the equivalent age is 75 percent of average life and when $x = +4.2$ the equivalent is 142 percent of average life.

Left-Modal No. 0

$$y_x = 6.24256418\left(1 - \frac{(x+5.06)^2}{24.60758105}\right)^{0.4411811}$$ for x values to left of 49.4 percent of average life, and

$$y_x = 6.24256418\left(1 - \frac{(x+5.06)^2}{1569.183739}\right)^{7.75906308}$$ for x values to right of 49.4 percent of average life.

Left-Modal No. 1

$$y_x = 7.45095687\left(1 - \frac{(x+4)^2}{85.49500000}\right)^{4.77742941}$$ for x values to left of 60 percent of average life, and

$$y_x = 7.45095687\left(1 - \frac{(x+4)^2}{697.8983268}\right)^{4.74147112}$$ for x values to right of 60 percent of average life.

Left-Modal No. 2

$$y_x = 6.2\left(1 + \frac{x - 0.56632298}{10.56632298}\right)^{2.00691507}\left(1 - \frac{x - 0.56632298}{18.11962398}\right)^{4.15639835}$$
$$+4.03141046\left(1 + \frac{x + 1.98831766}{4.90258200}\right)^{2.73360830}\left(1 - \frac{x + 1.98831766}{12.07825433}\right)^{8.19831032}$$

Left-Modal No. 3

$$y_x = 6.12\left(1 + \frac{x - 0.69997304}{9.94997304}\right)^{2.51767682}\left(1 - \frac{x - 0.69997304}{13.35543784}\right)^{3.72163230}$$
$$+8.19722280\left(1 + \frac{x + 1.22119072}{6.98766177}\right)^{10.15754029}\left(1 - \frac{x + 1.22119072}{16.85048078}\right)^{25.90598437}$$

LEFT-MODAL No. 4

$$y_x = 10.811999434\left[1 - \frac{(x+0.600)^2}{51.8400}\right]^{25.300}$$

$$+ 9.901828065\left[1 - \frac{(x+0.300)^2}{56.2500}\right]^{3.650} \qquad -10 \leqq x \leqq -0.6$$

$$y_x = 10.811999434\left[1 - \frac{(x+0.600)^2}{184.9600}\right]^{62.000}$$

$$+ 9.901828065\left[1 - \frac{(x+0.300)^2}{56.2500}\right]^{3.650} \qquad -0.6 \leqq x \leqq -0.3$$

$$y_x = 10.811999434\left[1 - \frac{(x+0.600)^2}{184.9600}\right]^{62.000}$$

$$+ 9.901828065\left[1 - \frac{(x+0.300)^2}{176.8900}\right]^{8.350} \qquad -0.3 \leqq x \leqq (13.6 - 0.6)$$

LEFT-MODAL No. 5

$$= 12.76925713\left(1 + \frac{x - 0.088051975}{5.9500}\right)^{4.7715}\left(1 - \frac{x - 0.088051975}{10.7500}\right)^{9.4275}$$

$$+ 16.28938438\left(1 + \frac{x + 0.161460055}{4.0000}\right)^{11.8000}\left(1 - \frac{x + 0.161460055}{5.7000}\right)^{17.2400}$$

SYMMETRICAL No. 0

$$y_x = 6.95219904\left(1 - \frac{x^2}{100}\right)^{0.74857140}$$

SYMMETRICAL No. 1

$$y_x = 9.08025966\left(1 - \frac{x^2}{100}\right)^{1.82839970}$$

SYMMETRICAL No. 2

$$y_x = 11.91103882\left(1 - \frac{x^2}{100}\right)^{3.70009374}$$

SYMMETRICAL No. 3

$$y_x = 15.61048797\left(1 - \frac{x^2}{100}\right)^{6.9015918}$$

SYMMETRICAL No. 4

$$y_x = 22.32936082\left(1 - \frac{x^2}{81}\right)^{11.93537940}$$

SYMMETRICAL No. 5

$$y_x = 33.22051575\left(1 - \frac{x^2}{64}\right)^{21.43782170}$$

SYMMETRICAL No. 6

$$y_x = 52.47259169\left(1 - \frac{x^2}{49}\right)^{11.63414220}$$

RIGHT-MODAL No. 1

$$y_x = 4.87234751\left(1 + \frac{x+2.1173}{19.08200310}\right)^{2.16036988}\left(1 - \frac{x+2.1173}{12.2}\right)^{1.02056945}$$

$$+2.95921394\left(1 + \frac{x-2.03848}{9.25013197}\right)^{2.69374074}\left(1 - \frac{x-2.03848}{6.76380495}\right)^{1.69831583}$$

RIGHT-MODAL No. 2

$$y_x = 6.89465710\left(1 + \frac{x+0.470}{30.05448169}\right)^{9.16816044}\left(1 - \frac{x+0.470}{9.05171312}\right)^{2.06241419}$$

$$+ 3.34428110\left(1 + \frac{x-0.470}{91.60465100}\right)^{100.000}\left(1 - \frac{x-0.470}{7.80000000}\right)^{7.600}$$

RIGHT-MODAL No. 3

$$y_x = 9.4035297069\left(1 + \frac{x+0.235}{17.61801370}\right)^{7.950}\left(1 - \frac{x+0.235}{7.18500000}\right)^{2.650}$$

$$+ 5.5945716839\left(1 + \frac{x-0.698}{17.31323077}\right)^{27.800}\left(1 - \frac{x-0.698}{6.25200000}\right)^{9.400}$$

RIGHT-MODAL No. 4

$$y_x = 15.20129316\left(1 + \frac{x+0.11}{17.92683200}\right)^{14.05850860}\left(1 - \frac{x+0.11}{5.41801100}\right)^{3.55112010}$$

$$+5.85667821\left(1 + \frac{x-0.70}{2.56783700}\right)^{3.66879450}\left(1 - \frac{x-0.70}{3.45398750}\right)^{5.27997721}$$

RIGHT-MODAL No. 5

$$y_x = 14.99330391\left(1 + \frac{x+0.12869}{7.0000000}\right)^{5.79473520}\left(1 - \frac{x+0.12869}{3.8764409}\right)^{2.76276990}$$

$$+15.44614441\left(1 + \frac{x-0.2086}{4.2350000}\right)^{6.05833400}\left(1 - \frac{x-0.2086}{2.4150000}\right)^{3.02500040}$$

MIPUG/MH II-11

Subject: MIPUG/MH I-15(q), Depreciation

c) Re: Attachment 5 and 7 – please provide a version of Attachment 5 and 7 with no Net Salvage.

ANSWER:

The following response was prepared by Gannett Fleming.

Please refer to the following attachments:

Attachment 1 shows the calculation of annual and accrued depreciation for account 1175D using the ASL procedure, being a version of MIPUG/MH I-15(q) Attachment 5 calculated without any net salvage provision.

Attachment 2 shows the calculation of composite remaining life for account 1175D using the ASL procedure, being a version of MIPUG/MH I-15(q) Attachment 7 calculated without any net salvage provision.

MANITOBA HYDRO

ACCOUNT 1175D - SPILLWAY

CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST OF INVESTMENT AS OF MARCH 31, 2010

YEAR (1)	ORIGINAL COST (2)	AVG. LIFE (3)	--ANNUAL ACCRUAL-- RATE (4)	AMOUNT (5)	EXP. (6)	--ACCRUED DEPREC.-- FACTOR (7)	AMOUNT (8)
INTERIM SURVIVOR CURVE.. IOWA 75-R2							
PROBABLE RETIREMENT YEAR.. 12-2131							
NET SALVAGE PERCENT.. 0							
1991	80,430,469.28	75.00	1.33	1,069,725.24	58.01	0.2265	18,219,914
1992	80,430,469.28	75.00	1.33	1,069,725.24	58.85	0.2153	17,319,093
1993	40,215,234.64	75.00	1.33	534,862.62	59.69	0.2041	8,209,136
2007	68,329.54	74.94	1.33	908.78	71.79	0.0420	2,872
2008	94,022.89	74.92	1.33	1,250.50	72.67	0.0300	2,824
2010	2,246.89	74.88	1.34	30.11	74.43	0.0060	14
	201,240,772.52			2,676,502.49			43,753,853

COMPOSITE ANNUAL ACCRUAL RATE, PERCENT .. 1.33

MANITOBA HYDRO

SUMMARY OF
CALCULATED ANNUAL AND ACCRUED DEPRECIATION
RELATED TO ORIGINAL COST OF INVESTMENT AS OF MARCH 31, 2010

ACCT	GP	AVG. AGE	ORIGINAL COST	--ANNUAL ACCRUAL-- RATE	AMOUNT	ACCRUED DEPRECIATION
1175D		18.7	201,240,772.52	1.33	2,676,502.49	43,753,853
GRAND TOTAL		18.7	201,240,772.52	1.33	2,676,502.49	43,753,853

MANITOBA HYDRO

ACCOUNT 1175D - SPILLWAY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF MARCH 31, 2010

INTERIM SURVIVOR CURVE.. IOWA 75-R2
PROBABLE RETIREMENT YEAR.. 12-2131
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1991	80,430,469.28	18,219,914	20,505,112	59,925,357	58.01	1,033,018
1992	80,430,469.28	17,319,093	19,491,308	60,939,161	58.85	1,035,500
1993	40,215,234.64	8,209,136	9,238,751	30,976,484	59.69	518,956
2007	68,329.54	2,872	3,232	65,098	71.79	907
2008	94,022.89	2,824	3,179	90,844	72.67	1,250
2010	2,246.89	14	16	2,231	74.43	30
	201,240,772.52	43,753,853	49,241,598	151,999,175		2,589,661

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 58.7 1.29

MANITOBA HYDRO

SUMMARY OF
CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST OF INVESTMENT AS OF MARCH 31, 2010

ACCT	GP	AVG. AGE	ORIGINAL COST	--ANNUAL ACCRUAL-- RATE	AMOUNT	BOOK RESERVE	REM. LIFE
1175D		18.7	201,240,772.52	1.29	2,589,661	49,241,598	58.69
GRAND TOTAL		18.7	201,240,772.52	1.29	2,589,661	49,241,598	58.69

MIPUG/MH II-11

Subject: MIPUG/MH I-15(q), Depreciation

d) Re: Attachment 5 – please provide all calculations in support of the values in columns (3), (4), (5), (6), (7) and (8). If these values are derived from other values on the table, please provide all calculations required to arrive at those underlying values.

ANSWER:

The following response was prepared by Gannett Fleming.

Column (3) – Average Life – Represents the average life expectancy before any impacts of the Life span year of 2131. When using the Average Service Life procedure, the value for most vintages will equal the 75 year average service life estimate. More recent vintages include a small adjustment caused by the mid year convention for the installation and retirement of assets.

Column (4) – Annual Accrual Rate – Is calculated as follows:

100% divided by Average Life (column 3)

Column (5) – Annual Accrual Amount – Is calculated as follows:

(Original cost (column 2) X (1– net salvage %)) X Annual Accrual Rate (column 4)

Column (6) – Expectancy – Is the probable remaining life for the surviving investment of each vintage. This column is calculated in the same manner as column (6) – Remaining life in Attachment 3 to MIPUG/MH I-15(q), as explained in the response to MIPUG/MH II-11(b).

Column (7) – Accrued Depreciation Factor – Is calculated in accordance with the same formulae as provided in the response to MIPUG/MH II-11(a).

Column (8) – Accrued Depreciation Amount – Is calculated as follows:

(Original cost (column 2) X (1 – net salvage %)) X Accrued Depn Factor (column 7)

MIPUG/MH II-11

Subject: MIPUG/MH I-15(q), Depreciation

e) Re: Attachment 7 – please provide all calculations in support of the values in columns (3), (4), (5), (6) and (7). If these values are derived from other values on the table, please provide all calculations required to arrive at those underlying values.

ANSWER:

The following response was prepared by Gannett Fleming.

Column (3) – Calculated Accrued – The values for each installation vintage as indicated in columns (3) are based on the age of the installation vintage expressed as a percentage of the age to the average life estimate. The specific values for each age interval were originally published in 1942 in the publication "Depreciation of Group Properties – Engineering Research Institute Bulletin 155 by Robley Winfrey, Iowa State University, Engineering Research Institute, Ames, Iowa. An excerpt of Bulletin 155 is provided in the attachment to MIPUG/MH-II-11(a). The formula relating to the Average-life procedure was used in this calculation.

Column (4) – Allocated Book Reserve – The total amount of allocated book reserve is determined from the company's actual financial sub-ledgers. The total amount by account is allocated to each vintage based on the calculated accrued depreciation amount for each vintage as a percentage of the total account calculated accrued depreciation. For example the Allocated booked reserve for the installation year of 1991 is determined as follows:

($20,041,469/$48,129,237)*$49,241,598

Where the $49,241,598 is based on a known amount from the company's accumulated depreciation sub-ledger.

Column (5) – Future Book Accruals – Is calculated as follows:

(Original cost (column 2) X (1 – net salvage %)) - Allocated Book Reserve (column 4)

<u>Column (6) – Remaining Life</u> – Is the probable remaining life for the surviving investment of each vintage. This column is calculated in the same manner as column (6) – Remaining life in Attachment 3 to MIPUG/MH I-15(q), as explained in the response to MIPUG/MH II-11(b).

<u>Column (7) – Annual Accrual</u> – Is calculated as follows:

(Future Book Accruals (column 5) / Remaining Life (column 6)

MIPUG/MH II-12

Subject: MIPUG/MH I-16(a)

a) Please show separately the depreciation for Wuskwatim Generation and Wuskwatim Transmission.

ANSWER:

Please see Manitoba Hydro’s response to PUB/MH II-93(b)(iii).

MIPUG/MH II-13

Subject: MIPUG/MH I-16(d)

a) Please confirm that dividends paid under an assumed NCN preferred equity interest are not linked to WPLP net income. If not confirmed, please indicate why a change to depreciation expenses, which would presumably change net income, would not change dividends to be paid.

ANSWER:

Dividends paid to NCN under an assumed preferred equity interest are linked to WPLP gross revenues. Under an assumed common equity interest, where dividends are a distribution of residual net income, dividends would be affected by depreciation and other expenses.

MIPUG/MH II-14

Subject: MIPUG/MH 19(b), Electric Heat

a) Please provide all evidence in support of a 10% shift to electric heat as being reasonable, as opposed to a higher or lower value.

ANSWER:

The 10% figure was intended to illustrate the potential impact of increased use of electric space heating on the electric load for sensitivity analysis purposes. The expected shift to electric heat is already incorporated into the Electric Load Forecast.

MIPUG/MH II-15

Subject: MIPUG/MH I -29(d), Vacancy Rate

a) Please provide detailed calculations that explain how the 6.2% vacancy rate was developed.

ANSWER:

The vacancy rate is calculated as the number of vacant positions (426) as a percentage of the total positions (6,882), as outlined in the table in MIPUG/MH I-29(d). This results in a vacancy rate of 6.2%. Vacant positions are attributable to a number of factors including the external hiring freeze as well as employee retirements and turnover of staff both internally and externally.

MIPUG/MH II-16

Subject: Undertaking #22 (Exhibit MH-35) from 2010 GRA

a) Please Confirm that in Undertaking #22 (Exhibit MH-35) of the 2010 GRA, Manitoba Hydro stated that "Wuskwatim G.S. is not required until 2019/20 from the perspective of the dependable energy criterion" based on the 2010/11 Power Resource Plan.

ANSWER:

Manitoba Hydro can confirm that Undertaking #22 (Exhibit #MH-35) of the 2010 GRA states:

"It is only in the last three years that the load growth has decreased to the point where Wuskwatim G.S. is not required until 2019/20 from the perspective of the dependable energy criterion."

MIPUG/MH II-16

Subject: Undertaking #22 (Exhibit MH-35) from 2010 GRA

b) Please update the table provided in Undertaking #22 (Exhibit MH-35) that documented System Firm Energy Demand and Dependable Resources (GW.h) for the 2011/12 Power Resource Plan with and without Wuskwatim.

ANSWER:

The following table is the table provided in Undertaking #22 (Exhibit #MH-35) from the 2010 GRA updated with information from the 2011/12 power resource plan. Rows have also been added to the table to show the impact on system surplus when both Wuskwatim and wind are deducted. Note that there is a persistent shortfall starting in 2011/12 when Wuskwatim and wind are deducted.

Please also see Manitoba Hydro's response to MIPUG/MH II-3(c).

System Firm Energy Demand and Dependable Resources (GW.h)
2011/12 Power Resource Plan - No New Generation

Fiscal Year	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
System Surplus with Wuskwatim	823	1826	1256	990	2212	2062	1877	1666	406
Wuskwatim	75	1205	1250	1250	1250	1250	1250	1250	1250
System Surplus w/o Wuskwatim	748	621	6	(260)	962	812	627	416	(844)
Wind	770	819	819	819	819	819	819	819	819
System Surplus w/o Wuskwatim and Wind	(22)	(198)	(813)	(1079)	143	(7)	(192)	(403)	(1663)

MIPUG/MH II-17

Subject: 30-100 kV impacts

The response to GAC/MH-1-25(b) indicates at page 18 the range of impacts on the GSL 30-100 kV class is larger than the range of impacts on the GSL >100 kV class.

a) Please provide a version of the table at page 18 of Attachment 1 to GAC/MH-1-24(c) assuming the minimum billing demand changes proposed for April 1, 2013 are not implemented (i.e., the contract demand and highest measured demand ratchets remain at 25% not 50%), but all other aspects of the time of use proposal are adopted as proposed.

ANSWER:

The table below provides the impact to customers of the proposed TOU rates incorporating 25% ratchets rather than the 50% ratchets being proposed.

	Number of Customers	
	Large 30-100 kV	**Large >100 kV**
> (5.0%)	6	4
(3.%) - (5.0%)	7	2
(1.%) - (3.%)	10	1
(1.)% - 1.%	5	4
1.% - 3.%	6	1
3.% - 5.%	2	0
> 5.0%	1	0
Total Customers	**37**	**12**

MIPUG/MH II-17

Subject: 30-100 kV impacts

The response to GAC/MH-1-25(b) indicates at page 18 the range of impacts on the GSL 30-100 kV class is larger than the range of impacts on the GSL >100 kV class.

b) Please provide the impact on Hydro's 2013/14 revenue from the adoption of the changes in part (a) above.

ANSWER:

Please see Manitoba Hydro's response to GAC/MH II-30(b) which provides the kVA impact between the 25% and 50% ratchets. The difference between the two ratchet amounts, adjusting for the on-peak demand differential and applying the proposed 2013/14 demand charges yields incremental revenue of approximately $453 thousand for the Large 30 to 100 kV customers, and approximately $74 thousand for the Large over 100 kV customers.

As noted in Manitoba Hydro's response to GAC/MH II-30(b), the revenues reported in the Proof of Revenue for the Large >30 kV customer subclasses do not reflect the difference between the 25% and 50% ratchets since it is assumed that customers most significantly impacted will revise their contracts.

MIPUG/MH II-17

Subject: 30-100 kV impacts

The response to GAC/MH-1-25(b) indicates at page 18 the range of impacts on the GSL 30-100 kV class is larger than the range of impacts on the GSL >100 kV class.

c) Please provide a revised version of the table in (a) based on the following 30-100 kV rate scenarios:

i. Maintain the traditional 0.14 cents/kW.h gap between the GS Large >100 kV and the GS Large 30-100 kV classes, and balance the revenues using the demand charge, specifically: winter on-peak 0.0531 cents/kW.h; summer on-peak 0.0431 cents/kW.h; off-peak 0.0267 cents/kW.h; demand charge as needed to balance revenues.

ii. Maintain demand charge at 75% of the COS derived demand charge (as per Appendix 13.1 page 20) consistent with the >100 kV proposal; specifically: demand charge at $4.35/kV.A on-peak; lower the proposed 30-100 kV energy charges by an equal cents/kW.h as needed to balance revenues.

iii. Same demand charges as in (ii) above, but maintain on-peak energy charges at the proposed level, and reduce off-peak energy charges to balance revenues.

ANSWER:

Based on the criteria specified in the question for i, ii, and iii (based on 25% ratchets), the rates for the GS Large 30-100 kV subclass (as shown on the following page) would produce the following bill impacts:

	GS Large 30-100 kV		
	i	**ii**	**iii**
> (5.0%)	6	6	6
(3.%) - (5.0%)	0	0	0
(1.%) - (3.%)	16	12	12
(1.)% - 1.%	5	7	4
1.% - 3.%	8	10	13
3.% - 5.%	1	1	1
> 5.0%	1	1	1
Total Customers	**37**	**37**	**37**

i) Based on the rates specified in the question for the Large 30-100 kV, that is:

Winter On-Peak	$0.0531
Non-winter On-Peak	$0.0431
Off Peak	$0.0267

The demand charge would have to be $3.95 to maintain revenue neutrality.

ii) Based on a demand charge of $4.35, the energy charges for the Large 30-100 kV, to achieve revenue neutrality, would be:

Winter On-Peak	$0.0523
Non-winter On-Peak	$0.0423
Off Peak	$0.0259

iii) Based on the demand charge as in ii) and the on-peak rates proposed in the application, that is:

Demand Charge	$4.35
Winter On-Peak	$0.0548
Non-winter On-peak	$0.0448

The off-peak energy charge would be $0.0239 which is lower than the off-peak energy charge proposed for the GS Large >100 kV subclass.

MIPUG/MH II-17

Subject: 30-100 kV impacts

The response to GAC/MH-1-25(b) indicates at page 18 the range of impacts on the GSL 30-100 kV class is larger than the range of impacts on the GSL >100 kV class.

d) Please provide a full set of billing determinants for 2013/14 for the April 1, 2013 proposed rates under the proposed time-of-use rates and under a rate design that rejects time of use rates and maintains rate design consistent with the current approach. Please ensure the units are shown for each of winter on-peak energy by class, summer on-peak energy by class and off-peak energy by class. For demand charge determinants, please show units based on on-peak demand (per TOU), monthly demand (per the previous rate design approach) and for each please show with and without the proposed new 50% contract ratchet.

ANSWER:

Please see Manitoba Hydro's response to GAC/MH II-30(a) which provides the billing determinants for the TOU periods. Manitoba Hydro's response to MIPUG/MH I-20(b) (pages 4, 9 and 10) provided the billing determinants for non-TOU rates for the Large >30 kV customer sub-classes.

MIPUG/MH II-18

Subject: Cost of Service

a) Given the Board has ordered that the cost of service study will not be reviewed until after the current first component of the GRA, how does Manitoba Hydro propose to support a differential rate increase for April 1, 2013.

ANSWER:

Rate increases which are meaningfully different from the General Consumers' average of 3.5% are proposed for three rate classes: General Service Small non-demand, General Service Large 0-30 kV and General Service Large 30 - 100 kV. The proposed increases for all other classes are very close to the average General Consumers' increase of 3.5% (ie. within the range 3.4% to 3.6%). For the three affected classes, the proposed increases are:

General Service Small, non-demand	3.0%
General Service Large 0-30 kV	4.5%
General Service Large 30 – 100 kV	4.0%

The basis for determining the extent of difference from the GCR average for each of these classes is the 2013 Prospective Cost of Service Study, the review of which has been deferred until after the current proceeding. However, for two of the three proposed class differential increases, there have been longstanding issues with respect to revenue cost recovery, which have persisted through several versions of the Cost of Service Study, as depicted below.

	Revenue Cost Recovery Ratio (%)	
	General Service Small non-Demand	General Service Large 0-30 kV
2006 Previous methodology	103.1	94.0
2006 Recommended methodology	107.4	90.1
2008 re: Order 117/06	104.3	90.4
2008 re: Order 116/08	101.4	89.9
2010	105.7	92.3
2011	104.8	91.9
2013	107.6	93.3

With respect to the proposed higher than average increase for the General Service Large 30-100 kV class, the 2013 Cost of Service Study currently shows the revenue cost coverage for this customer group as being 96.6%.

MIPUG/MH II-19

Subject: Stakeholder Consultation

a) Please provide copies of Hydro's presentations and handout materials prepared for stakeholder consultation meetings dated November 2, 2010 (>100 kV) and March 16, 2011 (30-100 kV).

ANSWER:

Please see Appendix 36 for copies of presentation as presented at the Time-of-Use stakeholder presentations dated November 2, 2010 and March 16, 2011.

MIPUG/MH II-20

Subject: Export Prices

On pages 2 of Manitoba Hydro's October 3, 2012 letter regarding Proposed Rates Effective April 1, 2013, Manitoba Hydro indicates that "Manitoba Hydro will periodically apply to adjust future TOU rates to continue sending a price signal that is comparable to anticipated firm export contracts that may be negotiated forward."

a) Please explain if Manitoba Hydro intends to apply to adjust future TOU rates as part of General Rate Application proceedings or as part of a separate process.

ANSWER:

Manitoba Hydro anticipates that, normally, applications to adjust future TOU rates would form part of a General Rate Application.

MIPUG/MH II-20

Subject: Export Prices

On pages 2 of Manitoba Hydro's October 3, 2012 letter regarding Proposed Rates Effective April 1, 2013, Manitoba Hydro indicates that "Manitoba Hydro will periodically apply to adjust future TOU rates to continue sending a price signal that is comparable to anticipated firm export contracts that may be negotiated forward."

b) Please indicate how adjustments may occur in the event anticipated firm export contract prices decline over a rate setting interval.

ANSWER:

Manitoba Hydro's intent is not to establish a TOU peak period price that exactly tracks to firm export contract prices, but rather to approximate those prices and trend with them over the long term. Embedded cost recovery, rate gradualism and understandability will continue to remain as integral components of rate setting. Generally the overall direction and level of export prices would be taken into account in future rate applications.

MIPUG/MH II-21

Subject: 50% Contract Demand Charge

On page 5 of Manitoba Hydro's October 3rd, 2012 letter regarding proposed rates to be effective April 1, 2013, Manitoba Hydro notes that "For the Large 30-100 kV sub-class, bill impacts will range from (14.2%) to 10.1%. For the Large >100 kV sub-class the impacts will range from (15.4%) to 6.6%. A few customers could experience bill increases greater than 10.1% due to the proposed contract ratchet provisions; these customers will have the opportunity to mitigate bill impacts by re-contracting."

a) Please indicate if the percentage rate impacts referenced at page 5 remain consistent with the rate impacts estimated at page 18 of Attachment 1 to GAC/MH-1-24(c). If not, please provide an updated table similar to page 18 of Attachment 1 to GAC/MH-1-24(c). For those customers in excess of 5% in the table, please provide each specific rate impact percentage.

ANSWER:

The percentage rate impacts related to implementation of Time-of-Use rates for General Service Large customers served at greater than 30 kV referenced on page 5 of Manitoba Hydro's October 3rd, 2012 letter were determined relative to the interim approved September 1, 2012 General Service Large rates. The Time-of-Use rate impact estimates provided on page 18 of Attachment 1 to GAC/MH I-24 c) were determined based on a comparative April 1, 2013 rate using the present General Service Large rate structure with an average 3.5 percent class rate increase, to be collected entirely through increasing the energy rate.

Rate impacts for customers identified as having a rate increase of greater than 5 percent on Page 18 as a direct result of the implementation of Time-of-Use rates are listed below:

General Service Large > 100 kV

Customer 1	6.8%

General Service Large 30 – 100 kV

Customer 1	7.6%
Customer 2	5.6%
Customer 3	8.4%

MIPUG/MH II-21

Subject: 50% Contract Demand Charge

On page 5 of Manitoba Hydro's October 3rd, 2012 letter regarding proposed rates to be effective April 1, 2013, Manitoba Hydro notes that "For the Large 30-100 kV sub-class, bill impacts will range from (14.2%) to 10.1%. For the Large >100 kV sub-class the impacts will range from (15.4%) to 6.6%. A few customers could experience bill increases greater than 10.1% due to the proposed contract ratchet provisions; these customers will have the opportunity to mitigate bill impacts by re-contracting."

b) Please indicate how Manitoba Hydro will apply the 50% demand charge to

i. Companies in the process of ramping up operations, with signed contracts for demand well above what they are using in the initial operation phases.
ii. Companies with seasonal or intermittent shut-down periods.
iii. Companies in the process of scaling back operations temporarily in response to economic downturns.
iv. Companies which employ intermittent load management strategies such as self-generation or demand side management practices to reduce their loads.

ANSWER:

i) Manitoba Hydro attempts to coordinate timing of supply agreements to the time frame in which customer load is commissioned and brought into service on the Manitoba Hydro system. This process recognizes the lead times for making improvements to the Manitoba Hydro system in order to provide the customer with additional capacity and related customer work required to construct facilities and install equipment that will be adding load on the Manitoba Hydro system.

In instances where customers are requesting capacity to be added well in advance of plans to place load on the Manitoba Hydro system and required system improvements have been undertaken by Manitoba Hydro, customers will be bound to the minimum 50 percent of contract demand provision stated in Manitoba Hydro's Time-of-Use rate application.

ii) Customers with seasonal or intermittent shut-down periods will be bound to the terms in Manitoba Hydro's Time-of-Use rate application, specifying a minimum demand bill equal to 50 percent of contract demand. The lower demand rates specified in the Time-of-Use rate application will generally reduce customer costs during these periods relative to the present rate structure, which has a lower minimum demand bill percentage but a higher demand rate.

iii) Similar to the response provided in ii), customers would be subject to the terms specified in Manitoba Hydro's Time-of-Use rate application. It should be noted that the lower demand rate specified in the Time-of-Use application will generally reduce customer's fixed costs when scaling back operations. Prior experience under these circumstances shows that customers are generally not able to significantly scale back peak demand when curtailing production. The lower demand rate specified in the time-of-use application will reduce monthly demand costs relative to present rates when customers scale back operations in response to economic downturns.

iv) In instances where customers implement demand side management practices that result in long term load reductions, the impact of the 50 percent of contract demand could be mitigated by reducing specified contract demands. In instances where customer-owned, self generation displaces customer load to levels below the 50 percent of contract threshold, examination of the circumstances will need to be undertaken to establish whether contract levels can be revised, thereby solidifying the long-term benefit to Manitoba Hydro, or whether requirements exist for the customer to retain the specified contract capacity for redundancy or back-up, which require Manitoba Hydro to maintain the higher capacity level.

MIPUG/MH II-21

Subject: 50% Contract Demand Charge

On page 5 of Manitoba Hydro's October 3rd, 2012 letter regarding proposed rates to be effective April 1, 2013, Manitoba Hydro notes that "For the Large 30-100 kV sub-class, bill impacts will range from (14.2%) to 10.1%. For the Large >100 kV sub-class the impacts will range from (15.4%) to 6.6%. A few customers could experience bill increases greater than 10.1% due to the proposed contract ratchet provisions; these customers will have the opportunity to mitigate bill impacts by re-contracting."

c) Please provide a list of all measures considered by Manitoba Hydro as alternatives to the 50% of contract demand charge ratchet to address the concern noted at page 2 of Manitoba Hydro's October 3, 2012 letter; i.e., "that unused capacity, reserved by customers through their specified contract demand levels, may impede the Corporation's ability to serve new and/or expanding load with existing transmission infrastructure, resulting in potential costs for new infrastructure that would not be required if unused capacity was released." For each measure, please provide a comparison of the impacts on the number of customers affected, the magnitude of impacts on target customers, any impacts on Hydro's revenues, and a comparison of the likely effectiveness of each approach to addressing the issue of contracted but unused capacity.

ANSWER:

Manitoba Hydro considered the application of an unused capacity charge at a reduced demand rate for the unused capacity between the specified contract demand and actual monthly on-peak demand as an alternative to the 50 percent minimum contract demand charge.

Reduced rate demand charges of $1.00 per kVA, $1.50 per kVA, and $2.00 per kVA were examined for application to the difference between the specified contract demand and actual monthly on-peak demand in order to determine the impact on customers with un-used capacity and establish the potential impact on Manitoba Hydro revenues.

The scope and number of customers impacted by this approach would have been considerably larger than the proposal filed in Manitoba Hydro's Time-of-Use rate application, since the majority of customers do not fully utilize their contract capacity. To mitigate the extent of this impact, a threshold equal to 90 percent of contract demand was considered as a limit for applying the lower unused capacity charge, with customers operating at greater than 90 percent of contract not being impacted.

The range of customer impacts for the $1.00, $1.50, and $2.00 per kVA demand charge for unused capacity using the 90 percent threshold level are noted below. Manitoba Hydro revenue impacts are compared to the Time-of-Use rate application.

Unused Demand Charge ($/kVA)	Customers # < - 5%	Customers -5% > # < 0%	Customers 0% < # < 5%	Customers # > 5%	Manitoba Hydro Revenue Impact
General Service Large > 100 kV					
$1.00	1	6	5	0	$762,591
$1.50	0	4	7	1	$1,289,815
$2.00	0	4	6	2	$1,817,038
General Service Large 30 – 100 kV					
$1.00	3	12	15	5	$870,532
$1.50	2	7	15	11	$1,596,154
$2.00	2	6	13	14	$2,321,776

Adoption of these measures would have had similar types of impacts to the proposed adoption of the 50 percent of contract demand provision in Manitoba Hydro’s Time-of-Use rate application. The effectiveness of the measure would have been dependent on the magnitude of the impact felt by each individual customer, with impacts increasing as the charge for unused capacity increased, the greater impacts creating increased awareness about the impact of unused capacity. Higher charges for unused capacity would have increased the number of customers impacted and therefore created greater awareness.

The 50 percent of contract demand provision was proposed for Manitoba Hydro’s Time-of-Use rate application for ease of application and similarity to current minimum demand bill provisions in the present rate, easing customer understanding of the measure.

MIPUG/MH II-22

Subject: GAC/MH-1-25(b)

a) For each month for the past 5 years, please indicate the number of (i) GS Large >100 kV and (ii) GS Large 30-100kV customers who would have paid a higher demand charge had the proposed 50% minimum contract demand ratchet been in place at that time. For each customer in each month, please indicate the added costs that would have been paid by the customer in that month (assuming no revisions were made to the contracted demand level).

ANSWER:

To prepare the data requested for a five year period is an undertaking requiring significant time and resources. Manitoba Hydro also notes that the 70% winter ratchet that was in effect until December 2009 would further complicate this calculation. Accordingly, Manitoba Hydro has prepared the requested analysis based on 2011/12 monthly billing data only. Please see the tables below.

There are 15 customers in the Large 30-100 kV customer group and four customers in the Large >100 kV customer group who would have been billed on the 50% of contract demand ratchet. Note that the 50% contract demand was compared to the customers highest maximum recorded demand (on or off peak) as this is what the customer's recorded demand was based on at the time. The revenue calculations are also based on the demand charge applicable at the time.

Table 1:

Additional kV.A Billed Due to 50% Contract Demand Ratchet													Total
GSL 30 - 100	**Apr-11**	**May-11**	**Jun-11**	**Jul-11**	**Aug-11**	**Sep-11**	**Oct-11**	**Nov-11**	**Dec-11**	**Jan-12**	**Feb-12**	**Mar-12**	
Customer 1	161	186	194	211	489	437	520	401	308	349	425	392	**4,072**
Customer 2	250	250	250	250	250	250	233	250	250	247	250	250	**2,980**
Customer 3	692	836	236	428	260	548	860	1,028	908	1,004	1,172	1,218	**9,190**
Customer 4	76	409	535	627	558	359	356	148	-	-	-	-	**3,070**
Customer 5	2,585	2,585	2,585	2,585	2,585	2,585	2,585	2,585	2,585	2,585	2,585	2,585	**31,020**
Customer 6	-	-	113	-	-	-	-	-	113	-	-	-	**226**
Customer 7	80	108	124	127	51	131	11	-	-	-	-	43	**674**
Customer 8	-	-	61	50	-	-	-	-	-	-	-	-	**111**
Customer 9	25	1,459	774	-	-	855	-	644	-	-	-	-	**3,756**
Customer 10	-	-	-	545	538	362	-	-	-	-	-	-	**1,444**
Customer 11	1,047	2,352	416	-	3,418	-	668	1,307	-	91	2,008	-	**11,308**
Customer 12	1,626	1,675	3,233	1,712	2,848	2,585	2,489	1,996	1,887	1,660	1,773	1,658	**25,143**
Customer 13	3,323	3,323	3,323	3,323	3,323	3,323	3,323	3,146	3,305	3,323	3,323	3,323	**39,675**
Customer 14	3,180	3,589	2,802	1,634	2,259	1,932	2,822	1,109	1,737	1,092	2,472	1,280	**25,908**
Customer 15	810	1,434	276	270	48	-	-	-	-	-	-	-	**2,838**
Total 30 to 100	**13,854**	**18,205**	**14,921**	**11,762**	**16,625**	**13,368**	**13,866**	**12,613**	**11,094**	**10,350**	**14,007**	**10,749**	**161,415**
GSL > 100 kV													
Customer 1	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	2,250	**27,000**
Customer 2	1,211	1,451	2,017	5,338	5,338	5,338	2,713	1,610	1,548	2,193	1,356	3,129	**33,239**
Customer 3	-	-	152	514	1,520	1,567	1,217	-	-	-	-	-	**4,970**
Customer 4	-	591	-	-	-	-	-	-	-	-	-	1,900	**2,490**
Total > 100 kV	**3,461**	**4,292**	**4,419**	**8,101**	**9,108**	**9,154**	**6,179**	**3,860**	**3,798**	**4,443**	**3,606**	**7,279**	**67,700**
Grand Total	**17,315**	**22,497**	**19,341**	**19,863**	**25,733**	**22,522**	**20,046**	**16,473**	**14,892**	**14,794**	**17,613**	**18,028**	**229,115**

Table 2:

Additional Revenue from 50% Contract Demand Ratchet (based on April 1, 2011 Rates)													Total
GSL 30 to 100	**Apr-11**	**May-11**	**Jun-11**	**Jul-11**	**Aug-11**	**Sep-11**	**Oct-11**	**Nov-11**	**Dec-11**	**Jan-12**	**Feb-12**	**Mar-12**	
Customer 1	$ 974	$ 1,125	$ 1,176	$ 1,276	$ 2,963	$ 2,650	$ 3,151	$ 2,429	$ 1,869	$ 2,112	$ 2,573	$ 2,375	**$ 24,673**
Customer 2	$ 1,515	$ 1,515	$ 1,515	$ 1,515	$ 1,515	$ 1,515	$ 1,413	$ 1,515	$ 1,515	$ 1,497	$ 1,515	$ 1,515	**$ 18,060**
Customer 3	$ 4,194	$ 5,066	$ 1,430	$ 2,594	$ 1,576	$ 3,321	$ 5,212	$ 6,230	$ 5,502	$ 6,084	$ 7,102	$ 7,382	**$ 55,692**
Customer 4	$ 461	$ 2,481	$ 3,245	$ 3,801	$ 3,383	$ 2,178	$ 2,155	$ 899	-	-	-	-	**$ 18,602**
Customer 5	$ 15,665	$ 15,665	$ 15,665	$ 15,665	$ 15,665	$ 15,665	$ 15,665	$15,665	$15,665	$15,665	$15,665	$ 15,665	**$ 187,981**
Customer 6	-	-	$ 685	-	-	-	-	-	$ 685	-	-	-	**$ 1,370**
Customer 7	$ 485	$ 656	$ 750	$ 768	$ 308	$ 791	$ 67	-	-	-	-	$ 261	**$ 4,086**
Customer 8	-	-	$ 370	$ 304	-	-	-	-	-	-	-	-	**$ 674**
Customer 9	$ 149	$ 8,840	$ 4,689	-	-	$ 5,183	-	$ 3,901	-	-	-	-	**$ 22,762**
Customer 10	-	-	-	$ 3,302	$ 3,258	$ 2,194	-	-	-	-	-	-	**$ 8,753**
Customer 11	$ 6,346	$ 14,254	$ 2,521	-	$ 20,712	-	$ 4,048	$ 7,920	-	$ 553	$12,170	-	**$ 68,524**
Customer 12	$ 9,855	$ 10,150	$ 19,593	$ 10,375	$ 17,257	$ 15,668	$ 15,083	$12,096	$11,437	$10,058	$10,743	$ 10,050	**$ 152,366**
Customer 13	$ 20,134	$ 20,134	$ 20,134	$ 20,134	$ 20,134	$ 20,134	$ 20,134	$19,062	$20,027	$20,134	$20,134	$ 20,134	**$ 240,433**
Customer 14	$ 19,270	$ 21,747	$ 16,978	$ 9,905	$ 13,687	$ 11,711	$ 17,101	$ 6,718	$10,527	$ 6,618	$14,980	$ 7,758	**$ 157,000**
Customer 15	$ 4,909	$ 8,690	$ 1,673	$ 1,636	$ 291	-	-	-	-	-	-	-	**$ 17,198**
Total 30 to 100	**$ 83,957**	**$110,324**	**$ 90,424**	**$ 71,275**	**$100,748**	**$ 81,010**	**$ 84,029**	**$76,435**	**$67,228**	**$62,723**	**$ 84,883**	**$ 65,140**	**$ 978,175**
GSL > 100													
Customer 1	$ 12,150	$ 12,150	$ 12,150	$ 12,150	$12,150	$ 12,150	$ 12,150	$12,150	$12,150	$12,150	$ 12,150	$ 12,150	**$ 145,800**
Customer 2	$ 6,537	$ 7,837	$ 10,891	$ 28,823	$28,823	$ 28,823	$ 14,648	$ 8,691	$ 8,359	$11,843	$ 7,322	$ 16,896	**$ 179,492**
Customer 3	-	-	$ 823	$ 2,773	$ 8,210	$ 8,461	$ 6,571	-	-	-	-	-	**$ 26,839**
Customer 4	-	$ 3,189	-	-	-	-	-	-	-	-	-	$ 10,258	**$ 13,447**
Total > 100	**$ 18,687**	**$ 23,176**	**$ 23,865**	**$ 43,746**	**$ 49,182**	**$ 49,434**	**$ 33,369**	**$20,841**	**$20,509**	**$23,993**	**$19,472**	**$ 39,304**	**$ 365,578**
Grand Total	**$102,644**	**$133,501**	**$114,288**	**$115,020**	**$149,930**	**$130,444**	**$117,398**	**$97,277**	**$87,737**	**$86,716**	**$104,355**	**$104,444**	**$1,343,753**

MIPUG/MH II-22

Subject: GAC/MH-1-25(b)

b) Please indicate the number of customers in each class who would persistently face higher bills under Hydro's contract demand ratchet proposal than under the current ratchet.

ANSWER:

Based on the information presented in response to MIPUG/MH II-22(a), there are nine customers who would face higher bills in every month under the proposed contract ratchet provisions. However, Manitoba Hydro anticipates that the change in the demand ratchet will encourage some customers to reduce their contract demand, and thus reduce their demand charges.

MIPUG/MH II-22

Subject: GAC/MH-1-25(b)

c) For each customer in part (b), please indicate the efforts Hydro has made to have the customer release persistently unused contract demand, and over what period these efforts have been made.

ANSWER:

Supply agreements for larger customers are reviewed by Manitoba Hydro's Key and Major Account Energy Service Advisors on a periodic basis as loads change and contracts are identified for review and renewal. Customers who have not utilized their contract demands are informed and discussions are had regarding their short and long term capacity needs. Legacy supply agreements do not require customers to release contracted capacity and at present, there is minimal incentive for customers to relinquish capacity, as there is no specific penalty or incentive for them to release unused contract demand.

MIPUG/MH II-22

Subject: **GAC/MH-1-25(b)**

d) **For each customer in part (b), please provide an indicative annual load factor for the customer based on (i) actual annual peak demand, (ii) contract demand and (iii) proposed billing demand under Hydro's proposed April 1, 2013 rate schedules.**

ANSWER:

The load factors for all customers reported in response to MIPUG/MH II-22(a) are provided below.

GSL 30 kV to 100 kV	Annual Load Factor		Monthly Average Billing Demand LF
	Max. Recorded Peak Demand	100% Contract Demand	Proposed April 2013 TOU Rates
Customer 1	47%	21%	42%
Customer 2	18%	5%	10%
Customer 3	74%	36%	71%
Customer 4	54%	34%	65%
Customer 5	46%	2%	3%
Customer 6	16%	14%	19%
Customer 7	38%	26%	47%
Customer 8	51%	39%	60%
Customer 9	55%	29%	58%
Customer 10	56%	62%	69%
Customer 11	53%	28%	57%
Customer 12	29%	11%	22%
Customer 13	17%	4%	9%
Customer 14	55%	26%	53%
Customer 15	53%	35%	61%
GSL > 100 kV			
Customer 1	40%	4%	7%
Customer 2	33%	15%	30%
Customer 3	43%	23%	45%
Customer 4	46%	35%	56%

MIPUG/MH II-22

Subject: **GAC/MH-1-25(b)**

e) **For each customer in part (b), please indicate whether the customer initially provided capital contributions to Hydro to pay for the capital costs of installation of transmission and distribution infrastructure. If for any of the customers the answer is yes, why would the customer now be required to "release" this capacity?**

ANSWER:

Large General Service customers served at 30 kV and above are required to provide capital contributions for dedicated portions of infrastructure required for provision of supply to their facilities, including taps, line extensions, etc. Costs incurred for dedicated facilities provide no additional benefit to Manitoba Hydro beyond that obtained from providing service to a specific customer (i.e. revenue for energy consumed) and are therefore provided on a cost recovery basis.

System improvement costs, which are incurred to enhance the capacity and operation of the bulk system, can be segregated into two categories. Those costs incurred to provide for general capacity improvements and operation of the transmission and distribution system are allocated to the general rate base in accordance with the cost of service study. Load growth from large customers is included in planning for regional transmission and distribution improvements. The second category includes costs incurred to provide capacity and support for a distinguishable new or expanding load brought onto the system by a specific customer, generally require a customer contribution in proportion to the share of their contribution to the requirement for the improvements. Such distinguishable load growth may force Manitoba Hydro to accelerate planned system improvements, or enhance portions of the system that would otherwise not be required.

Each customer listed in the response to part b) would have provided contributions for dedicated costs incurred to serve their facility. The vast majority of these contributions were related to dedicated infrastructure that provided no benefit to Manitoba Hydro in respect to general capacity or operational improvements. Systems improvement costs were incurred in some instances, primarily for conductor upgrades/additions and switching improvements. In those instances, the costs related to the customers' portion of the upgrades required a contribution.

Regional constraints at the transmission and distribution station level often occur further into the system than the improvements towards which a customer may contribute when adding load. The scope of a customer's contribution is determined at the time that service is requested, and may therefore not extend to the full reach of the regional system serving their localized area. Those components of the system, which were funded by the general rate base, may have provided adequate capacity at the time of the service request. As time advances, those components of the system may become constrained due to general load growth, requiring Manitoba Hydro to incur costs for station upgrades and other system improvements. Unused capacity contracted by customers contributes to those constraints and accelerates the timeline for expenditures needed increase capacity and support operation of the transmission and distribution system.

MIPUG/MH II-22

Subject: GAC/MH-1-25(b)

f) Please provide Hydro's definition for "sustained periods of time" as per paragraph 1 of GAC/MH-1-25(b). Is this intended to refer to periods of months, years, etc.?

ANSWER:

For the purposes of historical reference used in the response to GAC-MH I-25(b), "sustained periods of time" was intended to refer to periods of years.

<u>MIPUG/MH II-22</u>

Subject: **GAC/MH-1-25(b)**

g) **Please indicate what is meant by "Contractually, customers have historically not been required to release unused capacity in order for Manitoba Hydro to serve other load…". Is there a proposed change in the contractual obligations on customers to release unused capacity at this time, or only a change to impose demand charges on the customers for this unused capacity? If there is a also a proposed change in the contractual terms between Hydro and new or existing customers, please provide copies of the existing terms (if any) governing unused capacity, the proposed new terms governing unused capacity, the impact if any on existing customers (or whether such change would only apply to new customers) and the effective date when Hydro will begin implementing such new provisions in customer contracts.**

<u>ANSWER</u>:

Earlier legacy supply agreements do not have specific clauses enabling Manitoba Hydro to recover unused capacity after a specified period of time. More recent contracts do have such a clause included in the wording of the supply contract. The specific clause from the current version of the supply agreement in included as a reference below:

Clause 4 (b) of the current Supply Agreement states:

> *Manitoba Hydro shall have the right to decrease the amount of contracted power to reflect the customer's recorded demand at any time after a date which is ____ billing year(s) calculated from the 30th day of November next following the commencement date. Manitoba Hydro shall provide notice to the Customer prior to decreasing the amount of contracted power. The effective date of the decrease shall be the 1st day of December of the billing year next following the date of the notice, provided that the notice is given to the Customer at least 60 days prior to the start of the billing year, otherwise the effective date shall be the 1st day of December of the second billing year following the date of the notice.*

No customer subject to the current version of the supply agreement will be impacted based on current or projected operating demand levels. These terms only apply to customers entering into the new Supply Agreement, and therefore do not impact customers under older legacy agreements.

Manitoba Hydro has implemented this contract language in its agreements effective March 15, 2011.

MIPUG/MH II-22

Subject: GAC/MH-1-25(b)

h) For an industrial customer who does not use their contracted capacity for a sustained period of time, and consequently releases such capacity to Hydro for other customer use, would that industrial customer be required to make new capital contributions and/or risk failing to receive an allocation of future capacity in the event the originally contracted demand is required in future?

Under the April 1, 2013 proposed Time of Use rates, if a customer has a contract for 100 MV.A, an on-peak demand of 40 MV.A and an off-peak demand of 70 MV.A, would that customer still face a 50 MV.A ratchet demand charge (i.e., 50% of contract demand)? How would this added demand charge be in any way related to "unused capacity"?

ANSWER:

Customers that release capacity and subsequently request additional capacity may be required to make capital contributions for additional capacity if Manitoba Hydro incurs costs that are subject to customer contribution for providing the requested capacity increase.

Under the proposed time-of-use application, customers would be subject to a minimum demand charge based on the greatest of the measured on-peak demand, 50 percent of contract demand, or 50 percent of the highest recorded on-peak demand in the past 12 months.

As Manitoba Hydro's system load is greatest in the on-peak period, unused capacity in the on-peak period may be useful to Manitoba Hydro for providing service to other domestic customers served by the same regional portion of the transmission system. Serving that load may otherwise require expansion of the Manitoba Hydro system resulting in additional costs to the Corporation and its ratepayers.

It is important to recognize that under the current rate structure, the described customer profile would result in a peak demand bill of 70 MVA. The time-of-use proposal provides the customer with a lower peak demand bill of 50 MVA under that same scenario based on a minimum demand bill of 50 percent of contract demand.