MIPUG/MH II-1

Construction in Progress Balances (PUB/MH I-19)

a) With reference to the response to PUB/MH I-19 ii), please explain the nature of the $159.399 million contribution recorded against the Keeyask Generation Project.

ANSWER:

The table in the PUB/MH 1-19 response contained project classification errors. The revised table below has been corrected, and the amount of ($159 205) for the Wuskwatim-Transmission project represents a contribution from the WPLP General Partner to Manitoba Hydro. The contribution is eliminated upon consolidation of Manitoba Hydro's financial statements.

(in thousands of dollars)

Major New Generation & Transmission	Component of Capitalized Costs					
	Wages	Overhead	Materials & Other	Interest	Contributions	Total
Wuskwatim - Generation	3,592	1,144	20,607	8,267		33,609
Wuskwatim - Transmission	20,241	6,643	134,067	2,283	(159,205)	4,030
Herblet Lake - The Pas 230kV Transmission	2,316	658	8,411	370	(194)	11,560
Keeyask - Generation	20,954	6,373	237,912	79,765		345,003
Conawapa - Generation	10,995	3,106	105,475	17,293		136,869
Kelsey Improvements & Upgrades	3,277	984	15,320	2,530		22,111
Kettle Improvements & Upgrades	370	100	298	21		789
Pointe du Bois Improvements & Upgrades	4,841	1,329	19,032	1,879		27,080
Pointe du Bois - Transmission	750	212	429	56		1,447
Bipole 3	3,472	1,036	6,456	3,003		13,968
Riel 230/500kV Station	2,650	781	1,723	436		5,591
Total	**73,456**	**22,366**	**549,729**	**115,904**	**(159,399)**	**602,056**

MIPUG/MH II-2

Major Projects

a) Please expand the response to MIPUG/MH I-14 (a) to show the collective impact of these major projects on IFF09-1. Please indicate the impacts of Major Projects on each line item on the electricity operations operating statement (both revenues and expenses).

ANSWER:

The collection of major projects in this information request includes large projects such as Wuskwatim and Kelsey Rerunnering in the earlier years and Pointe du Bois, Keeyask and Conawapa in the later years of the IFF. In order to respond to this information request it would be necessary to undertake an analysis of system operation without these components in the system in order to determine the impact on revenues and operating costs in the IFF. Because such an analysis must consider system operations on the basis of an integrated system, this analysis is complex and cannot be undertaken in the time frame that is available.

Manitoba Hydro has provided information for an alternative development plan, in Appendix 15, that does not include the Keeyask project, the new export sales to MP and WPS and the U.S. interconnection.

Wuskwatim Power Limited Partnership statements are provided in response to PUB/MH I-42(b) and PUB/MH II-38(a), for the approximate impacts of Wuskwatim G.S. and the Herblet Lake The Pas 230kV Transmission.

MIPUG/MH II-3

DSM Savings

a) **With reference to CAC/MSOS/MH I-46 (a) – please explain, in broad terms, why the levelized value of a peak period kWh of DSM savings has declined in the 2009 Power Smart Plan relative to the 2007 Power Smart Plan.**

ANSWER:

The marginal cost for the 2009 Power Smart Plan was derived from the 2008 estimate of marginal cost while the 2007 Power Smart Plan was derived from the 2006 estimate of marginal cost. Marginal costs are largely derived from export prices which are predominantly denominated in U.S. dollars. There was a significant change in the currency exchange rate between 2006 and 2008 during which the U.S. dollar lost value relative to the Canadian dollar. This was the dominant factor that caused the estimate of marginal cost to decline during this period.

MIPUG/MH II-4

Cost of Service Study Terms of Reference

a) **With reference to the response to CAC/MSOS/MH-I-68 (a) – will Hydro also commit to file the Terms of Reference for the external contract to review the cost of service methodology with other parties to the current GRA proceeding?**

ANSWER:

The Terms of Reference was filed on May 25, 2010 with the PUB and Intervenors registered for the current Manitoba Hydro General Rate Application.

MIPUG/MH II-5

IFF09-1

a) Please provide separately the electric operations and gas operations debt:equity ratios for all years of IFF09-1.

ANSWER:

Manitoba Hydro tracks debt/equity ratios at the consolidated level only and no longer calculates stand-alone debt:equity ratios for its subsidiaries. Because the amount of equity in each of the subsidiaries is minimal, it will not impact the debt:equity ratio of the consolidated entity.

<u>MIPUG/MH II-5</u>

IFF09-1

b) Please provide copies of the consolidated and electric operations projected operating statements, balances sheets and projected cash flow statements assuming 2.9% annual general consumer revenue increases through the IFF forecast period.

<u>ANSWER</u>:

Please refer to the attached schedules.

CONSOLIDATED PROJECTED OPERATING STATEMENT
2.90% Rate Increases from 2011-2020
(In Millions of Dollars)

For the year ended March 31	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
REVENUES											
General Consumers	1,652	1,670	1,739	1,800	1,854	1,928	1,994	2,056	2,122	2,188	2,254
Extraprovincial	414	383	554	583	615	590	701	729	742	894	1,093
	2,066	2,054	2,293	2,383	2,468	2,518	2,694	2,785	2,864	3,082	3,347
Cost of Gas Sold	351	332	340	346	342	349	350	351	352	353	352
	1,715	1,722	1,953	2,037	2,126	2,169	2,344	2,434	2,512	2,730	2,995
Other	28	29	31	32	32	33	34	34	35	36	36
	1,742	1,751	1,984	2,069	2,158	2,202	2,378	2,468	2,547	2,765	3,032
EXPENSES											
Operating and Administrative	446	456	482	492	501	512	522	532	555	568	589
Finance Expense	454	451	509	569	571	591	578	598	644	736	947
Depreciation and Amortization	394	415	438	469	481	502	513	519	540	573	607
Water Rentals and Assessments	120	110	111	113	114	114	115	115	115	115	124
Fuel and Power Purchased	103	131	248	249	259	268	296	341	362	440	418
Capital and Other Taxes	97	99	100	104	109	116	125	133	140	146	150
	1,613	1,663	1,888	1,995	2,035	2,103	2,149	2,239	2,356	2,579	2,836
Non-controlling Interest	-	-	1	1	(2)	(5)	(9)	(11)	(12)	(15)	(14)
Net Income	129	88	98	75	121	94	220	218	178	172	182
Additional General Consumers Revenue											
General electricity rate increases		2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%
General gas rate increases		0.00%	1.50%	0.00%	1.00%	0.00%	1.00%	0.00%	1.00%	1.00%	0.00%
Financial Ratios											
Equity	26%	25%	24%	24%	22%	21%	20%	19%	19%	18%	19%
Interest Coverage	1.24	1.15	1.15	1.11	1.17	1.12	1.25	1.22	1.16	1.15	1.14
Capital Coverage	1.39	1.09	1.14	1.27	1.22	1.46	1.77	1.71	1.76	1.93	2.27

MIPUG-MH II-5(b)

CONSOLIDATED PROJECTED BALANCE SHEET
2.90% Rate Increases from 2011-2020
(In Millions of Dollars)

For the year ended March 31	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
ASSETS											
Plant in Service	13,097	13,626	15,691	16,213	16,654	17,387	17,844	18,579	21,071	22,401	25,835
Accumulated Depreciation	(4,800)	(5,171)	(5,562)	(5,985)	(6,414)	(6,864)	(7,320)	(7,787)	(8,275)	(8,799)	(9,357)
Net Plant in Service	8,297	8,455	10,129	10,228	10,240	10,523	10,524	10,792	12,796	13,602	16,478
Construction in Progress	1,949	2,460	1,343	1,820	2,840	3,856	5,534	6,950	6,161	6,448	4,170
Current and Other Assets	2,421	2,374	2,503	2,551	2,304	2,433	2,673	2,929	3,192	3,021	3,323
Goodwill	107	107	107	107	107	107	107	107	107	107	107
	12,775	13,397	14,082	14,705	15,492	16,920	18,838	20,778	22,257	23,179	24,079
LIABILITIES AND EQUITY											
Long-Term Debt	7,816	8,613	9,071	8,786	10,366	11,522	13,140	14,629	15,563	16,846	14,564
Current and Other Liabilities	2,246	2,000	2,187	2,991	2,165	2,368	2,482	2,738	3,117	2,588	5,589
Contributions in Aid of Construction	293	291	285	280	276	273	272	270	268	267	267
Retained Earnings	2,227	2,315	2,396	2,471	2,592	2,686	2,906	3,125	3,303	3,475	3,656
Accumulated Other Comprehensive Income	192	178	143	178	94	71	38	17	6	3	3
	12,775	13,397	14,082	14,705	15,492	16,920	18,838	20,778	22,257	23,179	24,079

CONSOLIDATED PROJECTED CASH FLOW STATEMENT
2.90% Rate Increases from 2011-2020
(In Millions of Dollars)

For the year ended March 31

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
OPERATING ACTIVITIES											
Cash Receipts from Customers	2,171	2,159	2,401	2,488	2,574	2,625	2,802	2,893	2,973	3,192	3,458
Cash Paid to Suppliers and Employees	(1,175)	(1,227)	(1,364)	(1,382)	(1,414)	(1,441)	(1,493)	(1,561)	(1,613)	(1,712)	(1,726)
Interest Paid	(474)	(445)	(504)	(568)	(578)	(577)	(582)	(601)	(669)	(769)	(965)
Interest Received	29	22	14	16	14	4	15	26	36	39	33
	551	510	547	553	596	611	742	758	726	749	801
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	900	800	600	600	1,600	1,400	1,800	2,000	1,800	1,600	1,000
Sinking Fund Withdrawals	262	227	27	103	483	-	3	-	-	456	171
Retirement of Long-Term Debt	(448)	(304)	(27)	(183)	(849)	(100)	(262)	(201)	(530)	(869)	(321)
Other	(36)	(12)	19	(10)	(13)	(11)	(13)	(14)	(14)	(26)	(15)
	678	712	619	509	1,220	1,289	1,529	1,785	1,255	1,161	835
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of contributions	(1,151)	(1,117)	(1,046)	(1,035)	(1,495)	(1,774)	(2,163)	(2,173)	(1,723)	(1,658)	(1,299)
Sinking Fund Payment	(94)	(99)	(98)	(116)	(176)	(107)	(201)	(159)	(242)	(200)	(256)
Other	(36)	(20)	(16)	(17)	(17)	(31)	(29)	(41)	(28)	(27)	(27)
	(1,281)	(1,236)	(1,160)	(1,168)	(1,687)	(1,912)	(2,393)	(2,372)	(1,993)	(1,885)	(1,582)
Net Increase (Decrease) in Cash	(52)	(15)	6	(105)	130	(12)	(122)	171	(11)	26	54
Cash at Beginning of Year	(32)	(84)	(99)	(92)	(198)	(68)	(81)	(203)	(31)	(42)	(16)
Cash at End of Year	(84)	(99)	(92)	(198)	(68)	(81)	(203)	(31)	(42)	(16)	38

MIPUG-MH II-5(b)

ELECTRIC OPERATIONS (MH09-1)
PROJECTED OPERATING STATEMENT
2.90% Rate Increases from 2011-2020
(In Millions of Dollars)

For the year ended March 31

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
REVENUES											
General Consumers											
at approved rates	1,160	1,159	1,177	1,191	1,204	1,229	1,244	1,260	1,272	1,283	1,297
additional *	-	33	69	106	145	188	231	277	325	374	427
Extraprovincial	414	383	554	583	615	590	701	729	742	894	1,093
Other	7	7	8	8	8	8	8	9	9	9	9
	1,581	1,584	1,808	1,888	1,972	2,015	2,185	2,275	2,347	2,560	2,826
EXPENSES											
Operating and Administrative	372	380	403	411	420	428	437	445	467	478	497
Finance Expense	417	413	468	525	527	547	534	553	599	690	901
Depreciation and Amortization	368	386	407	435	446	466	476	481	501	532	566
Water Rentals and Assessments	120	110	111	113	114	114	115	115	115	115	124
Fuel and Power Purchased	103	132	248	250	260	269	297	341	363	441	419
Capital and Other Taxes	73	76	77	80	85	92	100	109	115	121	124
Corporate Allocation	8	9	9	9	9	9	9	9	9	9	9
	1,460	1,505	1,723	1,824	1,861	1,924	1,967	2,054	2,168	2,386	2,640
Non-controlling Interest	-	-	1	1	(2)	(5)	(9)	(11)	(12)	(15)	(14)
Net Income	121	78	87	65	109	85	209	210	167	159	171
*Additional General Consumers Revenue											
Percent Increase		2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%
Cumulative Percent Increase		2.90%	5.88%	8.96%	12.11%	15.37%	18.71%	22.15%	25.70%	29.34%	33.09%

MIPUG-MH II-5(b)

ELECTRIC OPERATIONS (MH09-1)
PROJECTED BALANCE SHEET
2.90% Rate Increases from 2011-2020
(In Millions of Dollars)

For the year ended March 31	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
ASSETS											
Plant in Service	12,527	13,034	15,075	15,566	15,982	16,691	17,127	17,837	20,301	21,599	25,001
Accumulated Depreciation	(4,663)	(5,018)	(5,398)	(5,805)	(6,216)	(6,649)	(7,091)	(7,540)	(8,010)	(8,514)	(9,052)
Net Plant in Service	7,865	8,015	9,677	9,761	9,765	10,042	10,035	10,297	12,292	13,085	15,950
Construction in Progress	1,947	2,458	1,341	1,818	2,838	3,854	5,532	6,948	6,159	6,446	4,168
Current and Other Assets	2,767	2,735	2,871	2,926	2,684	2,811	3,047	3,303	3,565	3,393	3,697
Goodwill	42	42	42	42	42	42	42	42	42	42	42
	12,621	13,251	13,931	14,546	15,329	16,749	18,656	20,589	22,058	22,967	23,857
LIABILITIES AND EQUITY											
Long-Term Debt	7,800	8,596	9,054	8,769	10,349	11,505	13,123	14,612	15,546	16,829	14,547
Current and Other Liabilities	2,156	1,926	2,119	2,924	2,106	2,309	2,423	2,679	3,058	2,529	5,530
Contributions in Aid of Construction	290	288	284	280	276	275	274	273	272	271	271
Retained Earnings	2,183	2,261	2,331	2,396	2,504	2,590	2,799	3,009	3,176	3,335	3,506
Accumulated Other Comprehensive Income	192	178	143	178	94	71	38	17	6	3	3
	12,621	13,251	13,931	14,546	15,329	16,749	18,656	20,589	22,058	22,967	23,857

ELECTRIC OPERATIONS (MH09-1)
PROJECTED CASH FLOW STATEMENT
2.90% Rate Increases from 2011-2020
(In Millions of Dollars)

For the year ended March 31	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
OPERATING ACTIVITIES											
Cash Receipts from Customers	1,581	1,584	1,808	1,888	1,972	2,015	2,185	2,275	2,347	2,560	2,826
Cash Paid to Suppliers and Employees	(646)	(690)	(827)	(845)	(872)	(898)	(946)	(1,010)	(1,059)	(1,156)	(1,168)
Interest Paid	(453)	(423)	(479)	(542)	(551)	(549)	(554)	(573)	(641)	(740)	(936)
Interest Received	29	22	14	16	14	4	15	26	36	39	33
	511	493	516	517	563	572	699	718	683	702	755
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	745	800	600	540	1,600	1,400	1,800	2,000	1,800	1,600	1,000
Sinking Fund Withdrawals	262	227	27	103	483	-	3	-	-	456	171
Retirement of Long-Term Debt	(355)	(304)	(27)	(121)	(849)	(100)	(262)	(201)	(530)	(869)	(321)
Other	(35)	(10)	19	(10)	(14)	(12)	(13)	(14)	(15)	(26)	(15)
	618	713	619	512	1,220	1,288	1,529	1,785	1,255	1,161	835
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of contributions	(1,113)	(1,079)	(1,004)	(989)	(1,457)	(1,737)	(2,125)	(2,135)	(1,685)	(1,619)	(1,259)
Sinking Fund Payment	(94)	(99)	(98)	(116)	(176)	(107)	(201)	(159)	(242)	(200)	(256)
Other	(36)	(20)	(16)	(17)	(15)	(31)	(29)	(40)	(28)	(27)	(27)
	(1,243)	(1,198)	(1,118)	(1,123)	(1,648)	(1,876)	(2,355)	(2,334)	(1,954)	(1,846)	(1,543)
Net Increase (Decrease) in Cash	(114)	8	17	(94)	134	(15)	(127)	169	(16)	18	48
Cash at Beginning of Year	66	(48)	(40)	(23)	(117)	17	2	(125)	44	28	46
Cash at End of Year	(48)	(40)	(23)	(117)	17	2	(125)	44	28	46	94

MIPUG/MH II-6

Sinking Funds

a) With reference to the response to PUB/MH I-25 b), please elaborate on the "potential negative impacts that may result from credit rating agency reviews" from removing the sinking fund requirements.

ANSWER:

Liquidity levels provided by a large pool of sinking funds have been noted as a major credit rating strength factor in credit opinions provided by Standard & Poor's for the Province of Manitoba. It is unknown if the elimination of the sinking fund would negatively impact the credit rating of the Province of Manitoba through time and potentially increase Manitoba Hydro's credit spreads and borrowing costs.

<u>MIPUG/MH II-6</u>

Sinking Funds

b) With reference to the response to PUB/MH I-25 b), please confirm the $8 million impact results in lower expenses (i.e. cost savings).

<u>ANSWER</u>:

Confirmed.

MIPUG/MH II-7

EIIR Revenues

a) Please provide any updates to revenue forecasts for 2010/11 and 2011/12 based on Manitoba Hydro's most recent thinking with respect to a proposed EIIR.

ANSWER:

Please see Manitoba Hydro's response to CAC/MSOS II-32(b).

MIPUG/MH II-8

DSM Amortization Rates

a) Please discuss if the reduction in the amortization period of electric Power Smart Programs from 10 to 15 years has adversely affected the economics of any existing Power Smart Programs. If so, please provide details.

ANSWER:

Changing the amortization period of DSM programs has no affect on the economics of any Power Smart programs. Amortization is an accounting activity and this activity is unrelated to determining the economics of a Power Smart program. The economics of a Power Smart program is determined by calculating the 30-year net present value of program costs and benefits using the appropriate discount rate.

MIPUG/MH II-9

Marginal Costs

a) With reference to the response to CAC/MSOS/MH I-66 (c), please elaborate on the "Manitoba Hydro established methodology" for developing marginal cost estimates by function (Generation, Transmission and Distribution).

ANSWER:

Please refer to the response to RCM/TREE/MH II-4(b)(iii)(a)(i-ii) for a description of the methodology for determining the generation component of marginal cost. This component is derived from the change in production cost of system operation that can be expected over the range of flow conditions. The prices associated with export sales are the primary driver in determining this component of marginal cost. The generation component comprises about 85% of the total marginal cost and is driven primarily by energy savings as opposed to capacity savings.

The methodology for the transmission and distribution components is described in the response to RCM/TREE/MH II-4(b)(v)(a)(i-ii) and RCM/TREE/MH II-4(b)(vi)(a)(i-ii). These components are derived from ability to defer the requirements for infrastructure additions and are driven entirely by saving in capacity during the period of annual peak load requirements.

MIPUG/MH II-9

Marginal Costs

b) Please expand the response to CAC/MSOS/MH I-66 (c) to show the 2009/10 average embedded cost by function.

ANSWER:

The embedded cost by function can be found in PCOSS10 (pp 17 schedule B3) submitted as part of this application. Using the energy for each class in schedule B2 yields the following average embedded cost by function:

From PCOSS10	**Gen**	**Tran**	**Subtran**	**Dist Plant**	**Cust Serv**	**Total $/kW.h**
Residential	0.029	0.007	0.006	0.025	0.008	0.074
GS Small - Non Demand	0.031	0.007	0.005	0.019	0.009	0.071
GS Small - Demand	0.030	0.007	0.004	0.014	0.002	0.056
General Service - Medium	0.029	0.007	0.004	0.010	0.002	0.052
General Service - Large <30kV	0.029	0.006	0.003	0.008	0.002	0.048
General Service - Large 30-100kV	0.026	0.006	0.003	0.000	0.001	0.036
General Service - Large >100kV	0.026	0.005	0.000	0.000	0.000	0.031

Values shown are net of allocated export revenue

MIPUG/MH II-10

2009/10 Power Resource Plan (Appendix 47)

a) **With reference to page 5 of Appendix 47, please elaborate on the assumption that dependable energy is assumed to be reduced by 15 GW.h each year, subject to restrictions under the Prairie Province Apportionment Agreement. Please provide details on the relevant portion of the referenced agreement and indicate how the 15 GW.h/year reduction was estimated.**

ANSWER:

The reduction in dependable energy supply referenced in the 2009/10 Power Resource Plan (Appendix 47) is attributable to consumptive water uses in the Saskatchewan River basin based on projected irrigation demands and other consumptive uses over the 40-year planning horizon. A study entitled, "Canada-Saskatchewan South Saskatchewan River Basin Study" in 1992 provided streamflow projections at the Saskatchewan-Manitoba border for three time periods (1986, 2000 and 2020) to reflect the forecast of increased consumptive uses and regulation practices on the Saskatchewan River in Alberta and Saskatchewan. For long-range planning studies, the consumptive water use was extrapolated from the 1992 report and applied to long-term flow data files used in generation system simulation models. The quantity of 15 GW.h of reduced dependable energy supply annually is computed by incorporating the projected irrigation and consumptive uses from the aforementioned 1992 study of the Saskatchewan River into Manitoba Hydro's generation system studies model which is used to simulate long-term system energy production.

Under the Prairie Provinces Apportionment Agreement, Alberta and Saskatchewan have the right to retain up to 50% of the water naturally arising within their respective provincial borders. Historically, the average annual quantity of consumptive uses in the Saskatchewan River basin has not reached the full apportionment amount that could be withdrawn under the Prairie Provinces Apportionment Agreement. In addition, projected quantities of consumptive uses that are utilized by Manitoba Hydro are not limited by the apportionment agreement.

<u>MIPUG/MH II-10</u>

2009/10 Power Resource Plan (Appendix 47)

b) Are these dependable energy reductions also anticipated to affect new plants such as Wuskwatim, Conawapa and Keeyask over time? Please discuss.

<u>ANSWER</u>:

Since the Saskatchewan River comprises approximately 20% of the Nelson River dependable energy supply, the reduction in water flow due to increasing consumptive water use projected for the Saskatchewan River basin will reduce the overall dependable energy supply for Conawapa and Keeyask. However this flow reduction is estimated to result in a total energy reduction of less than 10 GW.h per year, and this is not significant relative to the total output of these projects.

These water flow reductions apply only to the Saskatchewan River system and therefore do not impact the Wuskwatim Generating Station.

MIPUG/MH II-11

IFF09-1

a) Please provide a copy of IFF09-1 that:

i. Removes the impact of Conawapa and Keeyask costs and revenues through the forecast period.

ii. Implements average annual domestic rate increases necessary to achieve a 75:25 debt to equity ratio in the last year of IFF09-1.

ANSWER:

The 2009/10 Power Resource Plan indicates that under dependable energy conditions new generation is required to meet Manitoba load requirements in 2022/23. A number of development plans were studied to meet Manitoba load requirements and all of them included Conawapa in combination with either thermal generation or Keeyask.

Financial statements for the 2009/10 Alternative Power Resource Development Plan that meets Manitoba load requirements without a new interconnection and without the MP and WPS Sales can be found in Appendix 15. This development plan assumes Conawapa is placed in-service in 2021/22 followed by a combined cycle gas turbine in 2033/24.

<u>MIPUG/MH II-12</u>

Demand Billing Concessions

Reference: MIPUG/MH I-21(d)

a) Please confirm that the Winter Ratchet savings illustrated in the table were calculated before the application of the demand billing concessions (i.e. they are calculated assuming the demand billing concession program were not in place). If this cannot be confirmed, please provide a version of the table that provides the calculation of the winter ratchet savings assuming the demand billing concession program were not in place.

<u>ANSWER</u>:

Confirmed.

MIPUG/MH II-12

Demand Billing Concessions

Reference: PUB/MH I-170(a)

b) Please confirm, as stated in the letter from P.J. Ramage to G. Gaudreau dated November 18, 2009, attached to the response to PUB/MH 1-170 (a), that certain customers who would otherwise have been eligible for the program elected not to apply given uncertainty with respect to whether the demand concession would be forgiven or require repayment.

ANSWER:

Concern about the deferral aspect of the Billing Demand Deferral Program was raised by many customers inquiring about the program. A key aspect of this concern was related to the fact that the “deferral” remained as a liability from a financial perspective, with the potential to increase future unit energy costs.

Due to this concern, several companies chose not participate in the Billing Demand Deferral Program, reducing the effectiveness of the program in assisting customers that were experiencing high unit energy costs during periods of curtailed operation resulting from the economic downturn.