

**MANITOBA PUBLIC UTILITIES BOARD**

**IN THE MATTER OF *The Crown Corporation Public Review and Accountability Act***

**AND IN THE MATTER OF Manitoba Hydro's  
2012/13 & 2013/14 General Rate Application**

**REBUTTAL EVIDENCE OF MANITOBA HYDRO**

**WITH RESPECT TO THE WRITTEN EVIDENCE OF:**

**PAUL CHERNICK, RESOURCE INSIGHT, INC. on behalf of Green Action Centre  
("GAC");**

**PATRICK BOWMAN, INTERGROUP CONSULTANTS LTD. on behalf of  
Manitoba Industrial Power Users Group ("MIPUG"); and,**

**PHILIPPE U. DUNSKY, DUNSKY ENERGY CONSULTING on behalf of  
Consumers' Association of Canada (Manitoba) and Green Action Centre  
("CAC/GAC")**

December 7, 2012



**MANITOBA HYDRO  
2012/13 & 2013/14 GENERAL RATE APPLICATION**

**REBUTTAL EVIDENCE**

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TABLE OF CONTENTS

1		
2	1.0	INTRODUCTION .....1
3	2.0	REVENUE REQUIREMENTS AND RATE PROPOSALS .....1
4	2.1	Issues Associated with the 2012/13 & 2013/14 Test Years (Prior to IFRS).....2
5	2.1.1	Manitoba Hydro’s Overhead Capitalization Practices are Consistent with
6		Canadian Electric Utilities .....2
7	2.1.2	Manitoba Hydro’s Overhead Capitalization Practices are Consistent with
8		PUB Findings & Recommendations .....3
9	2.1.3	Manitoba Hydro’s Overhead Capitalization Practices are Consistent with
10		Future Capital Spending Plans .....4
11	2.1.4	The Revised Service Lives Implemented by Manitoba Hydro Effective
12		April 1, 2011 are Reasonable .....6
13	2.1.5	Recovery of Net Salvage Costs in Depreciation Rates is a Legitimate
14		Regulatory Concept under a Rate-Regulated Accounting Model.....8
15	2.1.6	Manitoba Hydro’s Proposed Treatment of the Accumulated Depreciation
16		Surplus is Fair to Ratepayers .....9
17	2.1.7	Manitoba Hydro has Implemented Effective Cost Control Measures in
18		Minimizing Growth in OM&A Expenditures .....10
19	2.1.8	Manitoba Hydro’s Proposed Rate Increases are Reasonable and Serve to
20		Protect Customers .....11
21	2.2	Issues Associated with 2014/15 and Beyond (after IFRS Implementation) ..... 14
22	2.2.1	Rate-Regulated Accounting is currently Under Review by the IASB .....15
23	2.2.2	Manitoba Hydro’s Proposed Change to ELG Improves Intergenerational
24		Equity .....15
25	2.2.3	Manitoba Hydro’s Proposed Change to ELG is Appropriate for an Electric
26		Utility .....19
27	2.2.4	Changes to Manitoba Hydro’s Depreciation Methodology are required for
28		IFRS Compliance .....20
29	2.2.5	There is No Need for a Separate Set of Regulatory Financial Statements
30		Under the Cost of Service Rate Setting Methodology .....21
31	3.0	DEMAND SIDE MANAGEMENT .....24
32	3.1	Manitoba Hydro’s Demand Side Management Activities .....24

**MANITOBA HYDRO  
2012/13 & 2013/14 GENERAL RATE APPLICATION**

**REBUTTAL EVIDENCE**

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1	3.2	Estimate of Environmental Values.....	36
2	3.3	Accelerated DSM and Need for New Generation.....	36
3	4.0	FUEL SWITCHING REPORT .....	37
4	5.0	MARGINAL COST ESTIMATES .....	38
5	5.1	Generation Plant Investment Costs are Considered.....	38
6	5.2	Methodology for Marginal Transmission and Distribution Costs .....	38
7	6.0	NEED FOR WUSKWATIM.....	39
8	7.0	RATE OPTIONS .....	40
9	7.1	Curtable Rate Program.....	40
10	7.1.1	Low Capacity Prices in Neighbouring Markets due to Capacity Surpluses	40
11	7.1.2	No Long-term Commitment to Provide Curtailment Service .....	41
12	7.1.3	Manitoba Hydro has decided that additional CRP load is not required to	
13		respond to a MISO Maximum Generation Event .....	42
14	8.0	OTHER .....	43
15	8.2	Reviewability of Manitoba Hydro's Application.....	43
16	8.3	Consultation on Cost of Service and Time-of-Use Rate Proposal.....	44
17		ATTACHMENT A: COMPARISON OF ASL AND ELG SCENARIOS FOR A	
18		DECLINING ASSET POOL .....	47
19		ATTACHMENT B: COMPARISON OF ASL AND ELG SCENARIOS FOR AN ASSET	
20		POOL WITH A CONSTANT LEVEL OF INVESTMENT .....	51
21			

**MANITOBA HYDRO  
2012/13 & 2013/14 GENERAL RATE APPLICATION**

**REBUTTAL EVIDENCE**

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1 **1.0 INTRODUCTION**

2  
3 Manitoba Hydro's Rebuttal Evidence addresses the written evidence filed on behalf of the  
4 following parties with respect to Manitoba Hydro's 2012/13 & 2013/14 General Rate  
5 Application:

- 6 • Mr. Paul Chernick on behalf of the Green Action Centre (GAC);
- 7 • Mr. Patrick Bowman on behalf of the Manitoba Industrial Power Users Group  
8 (MIPUG); and,
- 9 • Mr. Philippe Dunsky on behalf of the Consumers' Association of Canada (CAC)  
10 and GAC.

11  
12 **2.0 REVENUE REQUIREMENTS AND RATE PROPOSALS**

13  
14 In this section of Manitoba Hydro's Rebuttal Evidence, Manitoba Hydro addresses the  
15 written evidence of Mr. Patrick Bowman on behalf of MIPUG regarding the proposed  
16 revenue requirements and rates.

17  
18 Mr. Bowman's evidence alleges that the proposed rate increases are not the result of  
19 declines in export prices but rather are necessitated by Manitoba Hydro's aggressive  
20 advancement of the recognition of capital related costs and to a lesser extent, the failure of  
21 Manitoba Hydro to control costs. While Mr. Bowman does not provide specific rate  
22 recommendations to the Public Utilities Board (PUB), instead preferring to finalize their  
23 recommendations after a review of IFF12, he tentatively recommends that rates for  
24 2012/13 and 2013/14 be finalized at the current levels approved on an interim basis as at  
25 September 1, 2012 and that the accumulated balance in the deferral account as at March  
26 31, 2012 related to the 1% rate-rollback directed in Order 5/12 be returned to customers.  
27 Manitoba Hydro reserves the right to provide additional Rebuttal Evidence based on Mr.  
28 Bowman's final recommendations.

29  
30 Mr. Bowman's evidence was developed based on information contained in IFF11-2 which  
31 assumed that Manitoba Hydro would implement International Financial Reporting  
32 Standards (IFRS) in the 2013/14 fiscal year, which is the second Test Year in the

1 Application currently before the PUB. On September 19, 2012, the Accounting Standards  
2 Board of Canada (AcSB) extended the optional transition date to IFRS for rate-regulated  
3 entities by an additional year to January 1, 2014. Manitoba Hydro has adopted the  
4 additional optional deferral and reflected IFRS implementation during its 2014/15 fiscal  
5 year in IFF12. As a result, there are no IFRS impacts contained in the 2012/13 and  
6 2013/14 Test Years as presented in IFF12.

7  
8 To assist the PUB in its review of the 2012/13 and 2013/14 Test Years, Manitoba Hydro  
9 has structured the Rebuttal Evidence into two sub-sections, first, those issues raised by Mr.  
10 Bowman that pertain to the proposed rate increases for 2012/13 and 2013/14 and secondly,  
11 those issues raised by Mr. Bowman that pertain to setting rates in the 2014/15 fiscal year  
12 and beyond by virtue of the deferral of IFRS by an additional year.

13  
14 Through these sections of the Rebuttal Evidence, Manitoba Hydro will demonstrate that  
15 the accounting and depreciation practices that form part of the revenue requirement  
16 calculations in the Application are appropriate and consistent with accepted rate-making  
17 principles for Canadian electrical utilities and that its cost control measures have been  
18 successful in constraining costs. Manitoba Hydro will demonstrate that the reasons for the  
19 proposed rate increases relate to the need to maintain the financial integrity of the  
20 Corporation in order to continue to provide safe and reliable service, and future rate  
21 stability for customers.

22  
23 Manitoba Hydro will also review the proposed accounting and depreciation changes to be  
24 made upon the adoption of IFRS in 2014/15 and outline how the associated impacts can be  
25 successfully managed within the cost of service rate setting methodology employed to set  
26 electric rates in Manitoba, while ensuring rate stability for customers.

27  
28 **2.1 Issues Associated with the 2012/13 & 2013/14 Test Years (Prior to IFRS)**

29  
30 Section 2.1 address those issues raised by Mr. Bowman that pertain to the proposed rate  
31 increases for 2012/13 and 2013/14, recognizing that IFRS implementation has now been  
32 deferred to Manitoba Hydro's 2014/15 fiscal year in IFF12.

33  
34 **2.1.1 Manitoba Hydro's Overhead Capitalization Practices are Consistent with**  
35 **Canadian Electric Utilities**

36  
37 Mr. Bowman opines that changes to Manitoba Hydro's overhead capitalization practices

1 over the 2008/09 to 2012/13 period do not reflect Manitoba Hydro's changing cost profile  
2 in terms of projected increases in capital spending and are shifting the burden of cost  
3 recovery of long-lived assets to current ratepayers which is resulting in unnecessary rate  
4 increases in the Test Years.

5  
6 Mr. Bowman is ignoring the information that was provided by Manitoba Hydro during the  
7 information request process that explains the reasons for the changes to overhead  
8 capitalization practices.

9  
10 Historically, electric utilities applied a full-cost accounting approach under Canadian  
11 Generally Accepted Accounting Principles (CGAAP) whereby common overhead charges  
12 such as depreciation on head office buildings were included in the cost of capital items.  
13 This interpretation and application of CGAAP was accepted by external auditors as it was  
14 consistent across the industry and thus, promoted comparability of the financial results of  
15 Canadian utilities. However, the interpretation and application of CGAAP by utilities has  
16 changed over the years such that there has been a reduction in the general and indirect  
17 overheads that are being capitalized today as compared to the past.

18  
19 As explained in the response to PUB/MH I-79(a) and PUB/MH II-52(a), the overhead  
20 capitalization changes implemented to date by Manitoba Hydro recognize industry trends  
21 to move away from full cost accounting and as a result are designed to make Manitoba  
22 Hydro's practices more consistent with those of other Canadian electric utilities. In the  
23 response to PUB/MH II-52(b) Manitoba Hydro outlined in detail the process and results of  
24 its consultations with other Canadian electric utilities as part of the review of its overhead  
25 capitalization practices and the fact that the changes that have been implemented to  
26 2012/13 under CGAAP are designed to ensure consistency with other Canadian electric  
27 utilities.

28  
29 These changes are fully compliant with CGAAP and have been fully endorsed by  
30 Manitoba Hydro's external auditors.

31  
32 **2.1.2 Manitoba Hydro's Overhead Capitalization Practices are Consistent with**  
33 **PUB Findings & Recommendations**

34  
35 Mr. Bowman's recommendation to return to the overhead capitalization practices  
36 employed by Manitoba Hydro prior to 2008/09 are not only inconsistent with electric  
37 utility practices, but they are also inconsistent with the past findings and recommendations

1 of the PUB.

2  
3 On pages 96 and 97 of Order 116/08, the final Order resulting from the 2008/09 General  
4 Rate Application (GRA), the PUB expressed concern over the aggressive deferral and  
5 capitalization of operating costs under the full cost accounting approach that was  
6 previously employed by Manitoba Hydro. The PUB was concerned that aggressive  
7 capitalization of operating costs would inappropriately burden future ratepayers and  
8 recommended in paragraph 2 at page 340 that the Company consider the early adoption of  
9 less aggressive IFRS overhead capitalization practices. In this context, the PUB is using  
10 the term less aggressive to mean capitalizing less overhead costs.

11  
12 The PUB further reiterated its concerns about the potential for aggressive deferral and  
13 capitalization of operating costs which could burden future ratepayers on page 85 of Order  
14 99/11 which was an interim Order relating to the 2010/11 & 2011/12 GRA. Through the  
15 last Electric GRA, the PUB and Intervenors were fully aware of the overhead capitalization  
16 changes that had been implemented or were planned to be implemented up to 2011/12 and  
17 the PUB did not take exception to these changes for rate-setting purposes in Order 5/12,  
18 the final Order resulting from the 2010/11 and 2011/12 GRA.

19  
20 Manitoba Hydro notes that MIPUG did not make any argument with respect to these  
21 overhead capitalization changes as part of the hearing process leading up to Order 5/12.  
22 Manitoba Hydro does not support a recommendation to return to the overhead practices  
23 employed by Manitoba Hydro five years ago, when the more recent changes have clearly  
24 been accepted for rate-making purposes by the PUB.

25  
26 At page 1-3, lines 26-27 Mr. Bowman also suggests in his evidence that Manitoba Hydro  
27 has not been sensitive to customer impacts in making these changes. Manitoba Hydro  
28 disagrees. Manitoba Hydro has been making changes gradually over the past number of  
29 years in an effort to transition them into customer rates and moderate the impact on  
30 customers.

31  
32 **2.1.3 Manitoba Hydro's Overhead Capitalization Practices are Consistent with**  
33 **Future Capital Spending Plans**  
34

35 Mr. Bowman's view that the changes to overhead capitalization practices are inconsistent  
36 with Manitoba Hydro's changing cost profile and projected increases in capital spending in  
37 the future is equally flawed. At page 4-10, lines 10-12, Mr. Bowman appears to be taking

1 the position that the changes to the overhead capitalization practices are somehow resulting  
2 in direct capital costs being expensed as operating costs. This is not the case. In pages 3 to  
3 5 of Appendix 5.6 of the Application and in the response to PUB/MH I-44(a) and  
4 PUB/MH I-79(a), Manitoba Hydro outlined the nature of the costs that are now being  
5 expensed under current industry practices as compared to the previous full cost accounting  
6 practices, as follows:

- 7 • Interest & Facilities Overhead on Stores
- 8 • Executive Costs
- 9 • Property Taxes on Facilities
- 10 • Interest on Common Assets
- 11 • General & Administrative Departmental Costs (e.g. Corporate Accounting,  
12 Library, Cash Management & Credit, Corporate Risk Management)
- 13 • Interest on Motor Vehicles
- 14 • Information Technology Infrastructure & Related Support Costs
- 15 • Building Depreciation & Operating Costs

16  
17 An examination of the nature of these costs would indicate that they are not direct capital  
18 expenditures, rather, they are sunk costs (i.e. building depreciation and IT infrastructure  
19 costs) or costs which do not vary directly based on the level of capital activity (i.e.  
20 Executive costs). Stated differently, it is appropriate that these overhead costs no longer be  
21 capitalized because they are relatively fixed and cannot be directly linked with a specific  
22 capital project. Without a direct relationship to a capital asset, these costs are more closely  
23 linked to current operations and as such it is appropriate from a rate-setting perspective that  
24 they be borne by the current ratepayers that derive the majority of the benefit from the  
25 expenditures.

26  
27 At page 4-10, lines 23-25, Mr. Bowman argues that Manitoba Hydro is not capitalizing  
28 costs associated with recent year's Equivalent Full Time position (EFT) additions despite  
29 the fact that this growth in EFTs was justified on the basis of Manitoba Hydro's growing  
30 capital program. Manitoba Hydro disagrees with this assertion. To the extent that such  
31 EFTs are working on a capital project, they will be required to directly charge to that  
32 project and as a result, the wages, benefits, and direct support costs associated with such  
33 EFTs will continue to be capitalized.

34  
35 In PUB/MIPUG I-15, Mr. Bowman has asserted that the capitalized EFTs are 679 lower in  
36 2013/14 than what Manitoba Hydro has calculated in PUB/MH II-49(a) and therefore



1 comes to the incorrect conclusion that Manitoba Hydro has not capitalized employee  
2 additions since 2004/05. Manitoba Hydro disagrees with the underlying formula and  
3 assumptions used by Mr. Bowman in coming to this conclusion. Mr. Bowman asserts that  
4 the impact of accounting changes must be deducted in order to properly reflect the correct  
5 capitalized EFT figure. This is incorrect as a significant portion of the accounting changes  
6 (i.e. depreciation, interest and property taxes on facilities and IT infrastructure) have no  
7 direct relationship with EFTs and should not be deducted in the calculation of capitalized  
8 EFTs. The capitalized EFT figure of 2825 for 2013/14 (per PUB/MH II-49(a))  
9 demonstrates the growth in EFTs necessary to support Manitoba Hydro's capital program.

10  
11 **2.1.4 The Revised Service Lives Implemented by Manitoba Hydro Effective April 1,**  
12 **2011 are Reasonable**

13  
14 Mr. Bowman's evidence expresses concern related to the service lives selected for some  
15 hydraulic generation and distribution components, specifically accounts 000A Dams,  
16 Dykes & Weirs, 000D Spillways, 4000J Distribution Poles & Fixtures and 4000L  
17 Distribution Overhead Conductor & Devices (please note, Mr. Bowman's evidence  
18 incorrectly describes account 4000J as Metal Towers).

19  
20 **Dams, Dykes & Weirs (Account 000A):** Mr. Bowman's evidence expresses concern that  
21 the service life adopted for this account is not sufficiently long given Manitoba Hydro's  
22 own retirement data. While it is generally expected that existing hydraulic generation  
23 plants will eventually be replaced at or near their current general location, the nature of the  
24 redevelopment for each site is as yet unknown. As such, it is not possible to determine the  
25 degree of modification that might be required to existing dams, dykes and weirs in  
26 association with the eventual future site redevelopment. From a rate-making perspective,  
27 the costs associated with the original construction of the dams, dykes and weirs should be  
28 recovered from the customers that benefit from the expenditure of those costs. Until such  
29 time as redevelopment plans mature to the point where it can be determined whether and  
30 how much of the current waterway infrastructure will be retained, only the customers in  
31 place during the lifespan of the existing powerhouse can be assured of receiving benefit  
32 from the associated dams, dykes and weirs. In the future, the service life estimates will be  
33 reviewed and adjusted in accordance with redevelopment plans as they become available.  
34 Customers receiving service from the redeveloped site should more appropriately bear the  
35 cost of the redevelopment efforts.

36  
37

1 **Spillways** (Account 000D): Mr. Bowman's evidence expresses concern that the service  
2 life adopted for this account is not sufficiently long given Manitoba Hydro's own  
3 retirement data. The IOWA curve for spillway assets indicates a greater level of early  
4 retirement than has been historically experienced by Manitoba Hydro. Due to age of  
5 existing plants, there is limited data to draw on with respect to historical retirements. The  
6 choice of a 75 year service life reflects the expectation for at least one major spillway  
7 replacement or refurbishment during the lifespan of a hydraulic generating station. The 75  
8 year service life is consistent with an average timing of actual and planned spillway  
9 remediation work of 76 years for the four oldest generating stations. Spillway remediation  
10 work was carried out at Seven Sisters in 1984 at age 53, and at Great Falls in 1986 at age  
11 63 (PUB/MH II-34a & PUB/MH II-34c). CEF12 reflects planned and in-progress spillway  
12 remediation work for Slave Falls at approximately 85 years and for Pointe du Bois at  
13 approximately 105 years.

14  
15 **Distribution Poles and Overhead Conductor** (Accounts 4000J & 4000L): Mr.  
16 Bowman's evidence opines that the lives adopted for these two accounts are excessively  
17 long given Hydro's own retirement data. As indicated in the response to PUB/MH I-82(e),  
18 the retirement data to which Mr. Bowman refers has been statistically developed using the  
19 computed mortality method. During the course of the depreciation study, it was determined  
20 that the statistically derived aging for these accounts did not align well with the actual age  
21 distribution of installed plant. The age distribution of the installed plant was under review  
22 through concurrent work to collect pole inventory data. The revised service life estimates  
23 for the depreciation study were developed with greater weight placed on actual pole  
24 inventory data and the representations of operational and engineering staff than on the  
25 statistical results produced during the depreciation study.

26  
27 The longer life adopted for depreciation rate purposes is consistent with the findings of  
28 Manitoba Hydro's Report on Distribution Asset Condition (Appendix 40). Based on the  
29 previous estimate for depreciation purposes of a 31 year service life for distribution poles  
30 with an R2 IOWA curve retirement profile, less than 5% of poles would be expected to  
31 survive to the age of 52 years. The 31-R2 service life assumption is not consistent with  
32 actual inventory findings which indicate that approximately 25% of the existing pole  
33 population was installed in conjunction with Rural Electrification, between 1945 and 1960.

1 These poles are currently between 52 and 67 years of age.<sup>1</sup> The revised assumption for  
2 depreciation purposes of a 55 year life with an R3 IOWA curve would anticipate  
3 retirement activity peaking at around 57 years of age. This is consistent with projections  
4 made by distribution staff for significant increases in pole replacement activity in the  
5 upcoming years as older poles reach the end of their life.

6  
7 The longer life estimate for distribution poles and conductor is also consistent with  
8 industry trends towards longer asset lives.

9  
10 **2.1.5 Recovery of Net Salvage Costs in Depreciation Rates is a Legitimate**  
11 **Regulatory Concept under a Rate-Regulated Accounting Model**

12  
13 In response to MH/MIPUG I-8, Mr. Bowman recommends that Manitoba Hydro remove  
14 net salvage costs from electric depreciation rates, commencing in the Tests Years.  
15 Manitoba Hydro's proposal is to remove net salvage costs from electric depreciation rates  
16 upon the adoption of IFRS in 2014/15.

17  
18 Manitoba Hydro does not recommend an early adoption of the removal of net salvage from  
19 depreciation rates as it is a valid construct for determining depreciation expense under the  
20 current rate-regulated accounting model. The purpose of including net salvage costs into  
21 depreciation rates it to ensure that the ratepayers benefitting from the respective assets are  
22 bearing the cost of removing those assets at the end of their useful life.

23  
24 Manitoba Hydro's proposal to eliminate this practice with the implementation of IFRS is  
25 driven by the fact that including net salvage costs in depreciation rates is not permitted  
26 under IFRS. Under IFRS, the future costs to retire and salvage assets will become a cost of  
27 the replacement asset. This approach, as recommended in Mr. Bowman's evidence, is  
28 consistent with requirements of IFRS and will be adopted by Manitoba Hydro upon its  
29 transition to IFRS.

30  
31  

---

<sup>1</sup> Appendix 40 – Manitoba Hydro Report on Distribution Asset Condition – November 9, 2012, page 107.

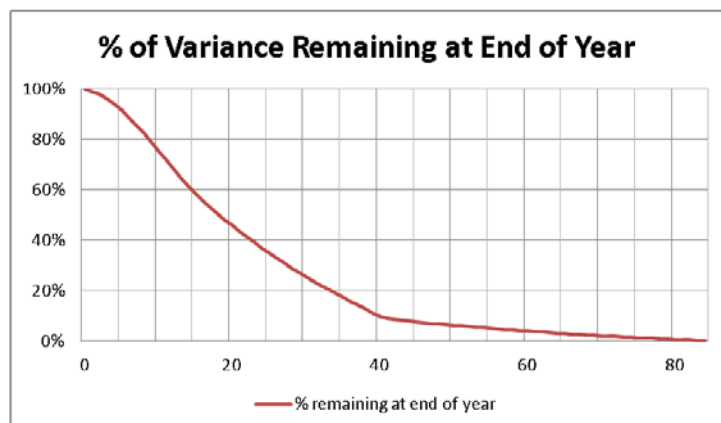
**2.1.6 Manitoba Hydro's Proposed Treatment of the Accumulated Depreciation Surplus is Fair to Ratepayers**

In response to PUB/MIPUGI-17, Mr. Bowman indicates that the accumulated depreciation surplus that results from the application of the proposed changes in the recent depreciation study should likely be refunded over the remaining life of the assets as proposed by Manitoba Hydro. However, Mr. Bowman's acceptance of this approach appears to be conditional on Manitoba Hydro also adopting the other approaches for the recognition of capital-related costs recommended in Mr. Bowman's evidence (e.g. the ASL approach, with no net salvage and full cost accounting overhead allocations).

Manitoba Hydro acknowledges Mr. Bowman's acceptance of Manitoba Hydro's approach to the handling of the accumulated depreciation surplus. The surplus accumulated over a long period of time, using depreciation rates that were based on the best information available and practices in use at the time. Refunding the surplus over the remaining life of the accounts to which they pertain is consistent with past regulatory practice, recognizes the long-term nature of the assets to which it relates, and is consistent with the objective of rate stability for customers.

At page 4-13, line 20, Mr. Bowman asserts that Manitoba Hydro proposes to amortize only \$7 million per year of the surplus balance, which implies an 80 year amortization period. In fact, the \$7 million represents only the first year of amortization of the balance as this amount will fluctuate from year to year as it is based on the different service lives of the multiple asset groups for which it pertains. Figure 1 shows that the majority of the amortization is expected to occur over 40 years.

Figure 1



1 Manitoba Hydro does not agree with Mr. Bowman's condition that the amortization of the  
 2 surplus over the life of the respective plant assets should only be implemented if Manitoba  
 3 Hydro also agrees to all of the other recommendations in Mr. Bowman's evidence.  
 4 Overall, the treatment of the surplus represents the appropriate regulatory treatment for the  
 5 nature of that particular balance.

6  
 7 **2.1.7 Manitoba Hydro has Implemented Effective Cost Control Measures in**  
 8 **Minimizing Growth in OM&A Expenditures**

9  
 10 Mr. Bowman contends that Manitoba Hydro's current cost control initiatives appear to  
 11 have had at most a small effect on the rate of growth in OM&A costs.

12  
 13 Manitoba Hydro has updated the analysis of the average annual increase in OM&A costs  
 14 to reflect cost projections per IFF12. Manitoba Hydro has limited increases in OM&A  
 15 costs to an average annual increase of 1.68% net of accounting changes and the  
 16 incremental costs associated with the in-service of the Wuskwatim Generating Station over  
 17 the period 2009/10 through 2013/14. This is below the average annual increase in  
 18 Canadian CPI of 2.10% over the same period. Please see Figure 2 below.

19  
 20 Figure 2

(in thousands of \$)	2009/10 Actual	2010/11 Actual	2011/12 Actual	2012/13 Forecast	2013/14 Forecast	Average Annual Increase
Electric OM&A (per Annual Report)	\$ 379,697	\$ 403,067	\$ 410,717	\$ 461,800	\$ 477,600	
Less: Subsidiaries	2,146	6,121	7,414	6,491	6,946	
Accounting Changes	11,240	30,910	34,973	75,411	78,318	
Wuskwatim				5,589	10,797	
Electric OM&A after adjusting for subsidiaries, accounting changes and Wuskwatim	<u>\$ 366,311</u>	<u>\$ 366,036</u>	<u>\$ 368,330</u>	<u>\$ 374,309</u>	<u>\$ 381,539</u>	
% Increase	4.28%	-0.08%	0.63%	1.62%	1.93%	1.68%
Number of Customers	532,359	537,299	542,681	548,944	555,955	1.06%
Cost Per Customer	\$ 688	\$ 681	\$ 679	\$ 682	\$ 686	
% Increase (Decrease)	3.32%	-0.99%	-0.37%	0.46%	0.65%	0.61%
Canadian CPI	1.40%	3.30%	1.90%	1.80%	2.10%	2.10%

21  
 22  
 23 Manitoba Hydro has achieved minimal cost increases despite significant cost pressures in  
 24 wages, salaries & overtime costs, benefits and other input commodities such as fuel.

25  
 26 The increase in wages and salaries is primarily due to negotiated contract settlements  
 27 reflecting competitive pressures in the market place in order to attract and retain skilled

1 employees in the increasingly competitive energy sector.

2  
 3 The increase in benefit costs reflects higher pension costs due to the amortization of  
 4 investment fund losses, higher vacation expense due to an increase in the number of days  
 5 accrued and higher extended health benefit costs due to negotiated coverage enhancements  
 6 (e.g. vision coverage, massage therapy, chiropractor). According to information provided  
 7 by Blue Cross, healthcare costs are increasing annually in the range of 8- 10% including  
 8 prescription drugs. For example, costs for eye exams have risen 10.6% from 2007 to 2011.  
 9 In addition, beginning in 2011/12 the reduction in the discount rate on pension and other  
 10 benefit obligations is also contributing to higher benefit costs.

11  
 12 Manitoba Hydro's commodity costs, such as fuel, have also increased by 4% since 2009/10  
 13 primarily due to higher prices. The following table, taken from Statistics Canada, provides  
 14 an overview of relevant input cost indices for Manitoba Hydro:

Commodity	Cost changes (January 2009 to December 2011)
Mineral Fuels	97%
Non-Ferrous Metals	47%
Wire and Cables > 1000v	22%
Ferrous Metals	6%

15  
 16  
 17 To offset these cost drivers, Manitoba Hydro has specifically implemented a number of  
 18 cost constraint initiatives including restrictions on external hiring, out of province travel,  
 19 overtime and reductions in community sponsorships and donations. Cost savings have  
 20 also been achieved as a result of the centralization of staff at both 360 Portage and 820  
 21 Taylor resulting in lower facility lease costs, maintenance and property services as well as  
 22 energy efficiencies in the new building. Manitoba Hydro has also engaged in continuous  
 23 process improvement activities to gain operational efficiencies and improve productivity in  
 24 managing its resources and controlling expenditures. Process improvements include  
 25 automation, utilization and coordination of resources, and reviews of work procedures  
 26 including standardized of work practices.

27  
 28 **2.1.8 Manitoba Hydro's Proposed Rate Increases are Reasonable and Serve to**  
 29 **Protect Customers**

30  
 31 The following table (Figure 3) summarizes Manitoba Hydro's actual electric operations net  
 32 income for the past five years and the projected net income for the 2012/13 and 2013/14

1 Test Years from IFF12, as well as the impacts of the interim rate increases that have been  
 2 implemented in 2012/13 and the proposed rate increase in 2013/14:

3  
 4

**Figure 3**

Net Income - Electricity Operations							
(in millions of \$)	2008	2009	2010	Actual 2011	2012	Forecast 2013 2014	
<b>Revenue</b>							
General Consumers Revenue							
- at approved rates	\$ 1,075	\$ 1,127	\$ 1,145	\$ 1,200	\$ 1,214	\$ 1,250	\$ 1,289
- 1% rate deferral					(23)		
Extraprovincial Revenue (net of Fuel & Power Purchased and Water Rentals)	366	323	202	172	98	97	62
Other Revenue	8	16	6	6	6	14	15
	<u>1,448</u>	<u>1,466</u>	<u>1,353</u>	<u>1,379</u>	<u>1,295</u>	<u>1,362</u>	<u>1,366</u>
<b>Expenses</b>							
	1,112	1,209	1,193	1,240	1,234	1,404	1,450
<b>Non-controlling Interest</b>							
			-	-	-	14	24
<b>Net Income (loss) before interim and proposed rate increases</b>							
	\$ 337	\$ 257	\$ 160	\$ 139	\$ 62	\$ (28)	\$ (59)
<b>Interim Rate Increases (2.0% April 1, 2012 &amp; 2.5% September 1, 2012)</b>							
	-	-	-	-	-	45	58
<b>Proposed rate increases (3.5% April 1, 2013)</b>							
	-	-	-	-	-	-	48
<b>Rate rollback reinstatement</b>							
	-	-	-	-	-	36	14
<b>Net Income after proposed rate increases &amp; rate rollback reinstatement</b>							
	<u>\$ 337</u>	<u>\$ 257</u>	<u>\$ 160</u>	<u>\$ 139</u>	<u>\$ 62</u>	<u>\$ 53</u>	<u>\$ 60</u>

**Retained Earnings and Financial Ratios (before interim & proposed rate increases)**

Retained Earnings (electric operations)	\$ 1,772	\$ 2,029	\$ 2,189	\$ 2,328	\$ 2,390	\$ 2,362	\$ 2,303
Debt to Equity Ratio (electric operations)	0.73	0.77	0.72	0.72	0.74	76:24	79:21
Interest Coverage Ratio (electric operations)	1.72	1.50	1.33	1.26	1.11	0.95	0.90
Capital Coverage Ratio (electric operations)	1.65	1.82	1.28	1.22	1.10	0.90	0.67

**Retained Earnings and Financial Ratios (after proposed rate increases & rate rollback reinstatement)**

Retained Earnings (electric operations)	\$ 1,784	\$ 2,028	\$ 2,190	\$ 2,328	\$ 2,390	2,442	2,502
Debt to Equity Ratio (electric operations)	0.73	0.77	0.72	0.72	0.74	75:25	78:22
Interest Coverage Ratio (electric operations)	1.72	1.50	1.33	1.26	1.11	1.09	1.10
Capital Coverage Ratio (electric operations)	1.65	1.82	1.28	1.22	1.10	1.09	0.89

5  
 6  
 7  
 8  
 9

Tab 2 of the Application and PUB/MH I-61 (a) set out a number of important justifications for the proposed increases. IFF12, in particular, and Figure 3 above further substantiate these justifications, notably:

10 1) **To avoid incurring losses on operations.** As noted in Figure 3, without the rate  
 11 increases that have been approved on an interim basis for 2012/13, the  
 12 reinstatement of the 1% rate roll-back and the further proposed rate increase of  
 13 3.5% on April 1, 2013, Manitoba Hydro is projected to incur losses on electric  
 14 operations of \$28 million in 2012/13 and \$59 million in 2013/14.

15  
 16  
 17  
 18

Based on the update of water flow conditions and the various other assumptions that form part of IFF12 and assuming that the interim and proposed rate increases are approved and the 1% rate roll-back is reinstated in 2012/13, Manitoba Hydro is

1 projecting a moderately higher net income (compared to IFF11-2) in 2012/13 of  
2 \$53 million and a slightly lower net income in 2013/14 of \$60 million, which are  
3 consistent with the actual net income from 2011/12. However, these projected  
4 income levels are significantly down from the average levels of the previous five  
5 years.

6  
7 Allowing the utility to incur a net loss on operations is not in the best interest of  
8 electricity ratepayers and could result in the requirement for substantially higher  
9 rate increases in the future.

- 10  
11 2) **To limit the extent to which financial ratios are projected to deteriorate and to**  
12 **maintain the financial and credit rating integrity of Manitoba Hydro.** In  
13 IFF12, the electric operations debt to equity ratio is projected to meet the 25%  
14 target in 2012/13 and to deteriorate to 22% in 2013/14 and the interest coverage  
15 ratio is projected to be 1.09 and 1.10 in 2012/13 and 2013/14, respectively.  
16 Without the proposed rate increases, the debt to equity ratio is projected to  
17 deteriorate to 24% in 2012/13 and to 21% in 2013/14 and interest coverage ratio is  
18 projected to be 0.95 and 0.90 in 2012/13 and 2013/14, respectively.

19  
20 In particular, Manitoba Hydro is concerned about the deterioration of its interest  
21 coverage ratio below 1.00 given the importance of this financial metric to  
22 bondholders and credit rating agencies and the potential negative consequence for  
23 the credit rating of the Province of Manitoba and Manitoba Hydro. See Manitoba  
24 Hydro's response to CAC/MH I-6 for additional information regarding the  
25 importance of Manitoba Hydro's financial ratios.

- 26  
27 3) **To compensate for the reduced prices for non-firm electricity sales on the**  
28 **export market.** The above summary table demonstrates that there has been a  
29 significant reduction in net extraprovincial revenues over the last number of years  
30 which is primarily due to low export prices, and is projected to continue into the  
31 2012/13 and 2013/14 Test Years.

32  
33 In IFF11-2 there was a reduction in forecast net extraprovincial revenues of \$4.0  
34 billion as compared to IFF10-2 over the 20 year period to 2031/32. In IFF12 there  
35 is a further reduction in forecast net extraprovincial revenues of \$2.9 billion as  
36 compared to IFF11-2 over the 20 year period to 2031/32.



1 The reductions in net extraprovincial revenues will have a significant negative  
2 impact on the net income of Manitoba Hydro in the Test Years. At page 4-1 of his  
3 written evidence, Mr. Bowman concludes that the reductions in net extraprovincial  
4 revenues will be “largely addressed by other offsetting factors within Hydro’s cost  
5 structure”. For example, Manitoba Hydro does not understand the basis under  
6 which a reduction in net income (largely driven by a reduction in net  
7 extraprovincial revenues) could be viewed as a cost structure offset to  
8 extraprovincial revenues. While there may be some partial offsets (for example  
9 with fuel costs), the reality is that the magnitude of the reduction in extraprovincial  
10 revenues will adversely impact net income and it is important from a rate stability  
11 perspective to recognize this reduction in customer rates on a gradual basis.

- 12
- 13 **4) To provide customers with rate stability and predictability and to avoid the**  
14 **need for much higher rates in the future.** The proposed rate increases are in  
15 keeping with Manitoba Hydro’s approach to implement regular and modest rate  
16 increases to ensure the maintenance of an adequate financial structure. A sufficient  
17 level of equity allows the Corporation to withstand the risks and uncertainties  
18 inherent in its operations and to address adverse financial consequences outside of  
19 its control and in so doing, promote rate stability and avoid the need for large or  
20 sudden rate increases in the future. Even with the proposed rate increases in the  
21 Test Years and the indicative rate increases in IFF12, the electric operations  
22 retained earnings are projected to be relatively flat to 2021/22.

23

24 Mr. Bowman’s recommendation to increase rates at the rate of inflation only does not  
25 compensate for the forecast reduction in net extraprovincial revenues and would be  
26 insufficient to maintain a reasonable level of net income and financial ratios. It also places  
27 future rate stability at risk and increases the risk of potential negative consequences to the  
28 credit rating of the Province of Manitoba and Manitoba Hydro.

29

30 **2.2 Issues Associated with 2014/15 and Beyond (after IFRS Implementation)**

31

32 As a result of the additional one-year deferral of IFRS for rate-regulated entities, Manitoba  
33 Hydro will now adopt IFRS in its 2014/15 fiscal year. Accordingly, Manitoba Hydro will  
34 also defer the adoption of a number of accounting policy changes that were designed to be  
35 IFRS compliant such as the write-off of rate-regulated assets, further reductions to  
36 overhead capitalized, removal of asset retirement costs from depreciation rates and the  
37 change to the Equal Life Group depreciation method for financial reporting purposes.

1 These changes no longer impact the setting of rates for the 2012/13 and 2013/14 Test  
2 Years, but rather will influence rate-setting in the 2014/15 period and beyond. Mr.  
3 Bowman's evidence was developed before these changes were incorporated into IFF12 and  
4 filed with the PUB and Intervenors and as such, Manitoba Hydro will address them  
5 separately in Section 2.2.

### 6 7 **2.2.1 Rate-Regulated Accounting is currently Under Review by the IASB**

8  
9 In its evidence, Mr. Bowman is critical of Manitoba Hydro for "electing" to write-off all of  
10 its deferred Power Smart DSM costs and to commence expensing of these costs as they are  
11 incurred as part of the implementation of IFRS. Mr. Bowman noted that the reason for the  
12 delays in implementing IFRS for utilities is due to the active and unresolved debate  
13 surrounding the recognition of rate-regulated accounting under IFRS.

14  
15 Mr. Bowman's characterization of Manitoba Hydro "electing" to write-off DSM costs  
16 upon transition to IFRS is incorrect. Manitoba Hydro's assumption that DSM costs will be  
17 written off on transition to IFRS is not an optional election, but rather was based on years  
18 of discussion and analysis in the utility industry indicating that continued recognition of  
19 rate-regulated assets would not be permitted under IFRS. While the International  
20 Accounting Standards Board (IASB) has recently reinitiated its rate-regulated activities  
21 project and there is potential that an IFRS standard may be developed that would allow for  
22 the recognition of rate-regulated accounting, the project has yet to reach a stage where any  
23 forecast assumption other than de-recognition would be considered reasonable.

24  
25 Manitoba Hydro will continue to monitor the status of the IASB rate-regulated activities  
26 project and will adjust its accounting policies and financial forecasts accordingly. For the  
27 purposes of the 2013/14 Test Year review, the assumed write-off of DSM has been  
28 deferred to 2014/15 in IFF12.

### 29 30 **2.2.2 Manitoba Hydro's Proposed Change to ELG Improves Intergenerational** 31 **Equity**

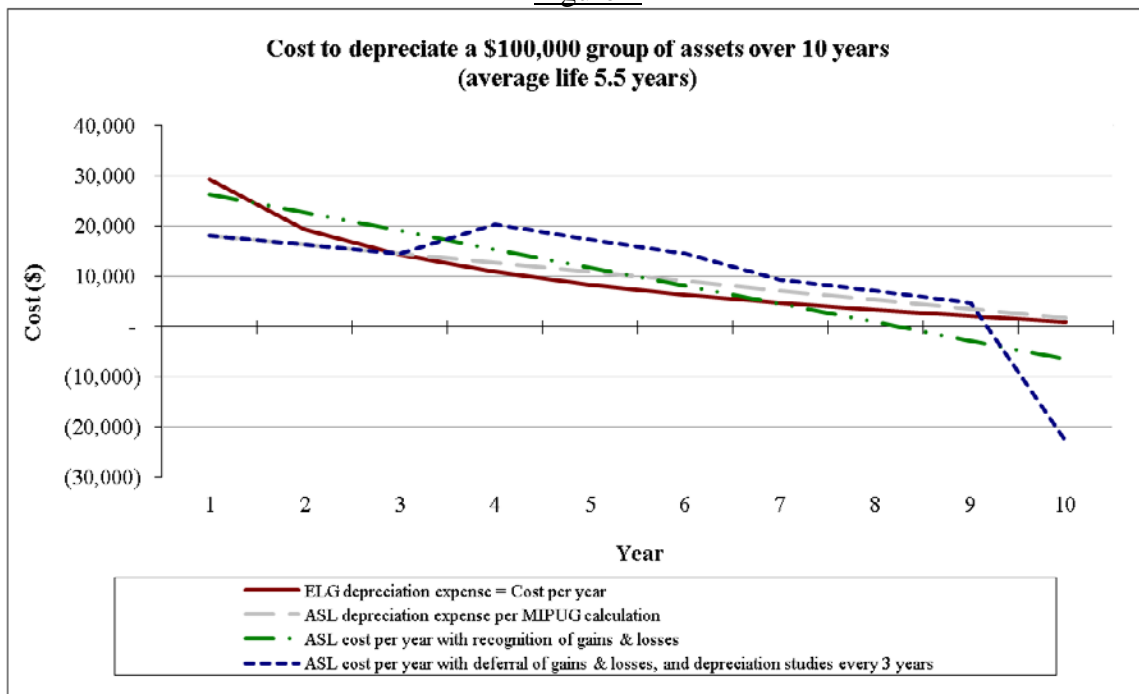
32  
33 Mr. Bowman's evidence opines that Manitoba Hydro's proposed adoption of the Equal  
34 Life Group (ELG) method of depreciation under IFRS is onerous to current ratepayers and  
35 recommends that the Average Service Life (ASL) method should be retained for rate-  
36 setting purposes to be consistent with other Crown owned and hydro dominated utilities.

37

1 Mr. Bowman asserts that the ELG approach results in far higher costs to ratepayers in the  
2 early years than ASL and provides an example in the response to MH/MIPUG I-4 which  
3 on the face of it, appears to support that conclusion. However, the ASL calculations  
4 provided by Mr. Bowman fail to consider the accounting for the gains and losses resulting  
5 from the retirement of assets. For the declining asset balance scenario provided by Mr.  
6 Bowman, use of ASL results in an earlier recognition of expense than ELG when the  
7 impact of gains and losses on asset retirements are considered.

8  
9 The total net cost to ratepayers including the impacts of gains and losses is shown in the  
10 following chart (Figure 4). Supporting calculations may be found in Attachment A:

11  
12 Figure 4



13  
14  
15 Under an ASL scenario where the gains and losses resulting from retirement are  
16 recognized as incurred, the entire \$100,000 original cost is charged to ratepayers in the first  
17 5.5 years, while ratepayers in the later years benefit from the realization of gains on the  
18 retirement of assets. The net cost charged to rate payers in years 6-8 is returned in years 9-  
19 10 when the magnitude of the gains exceeds the annual depreciation expense charged.

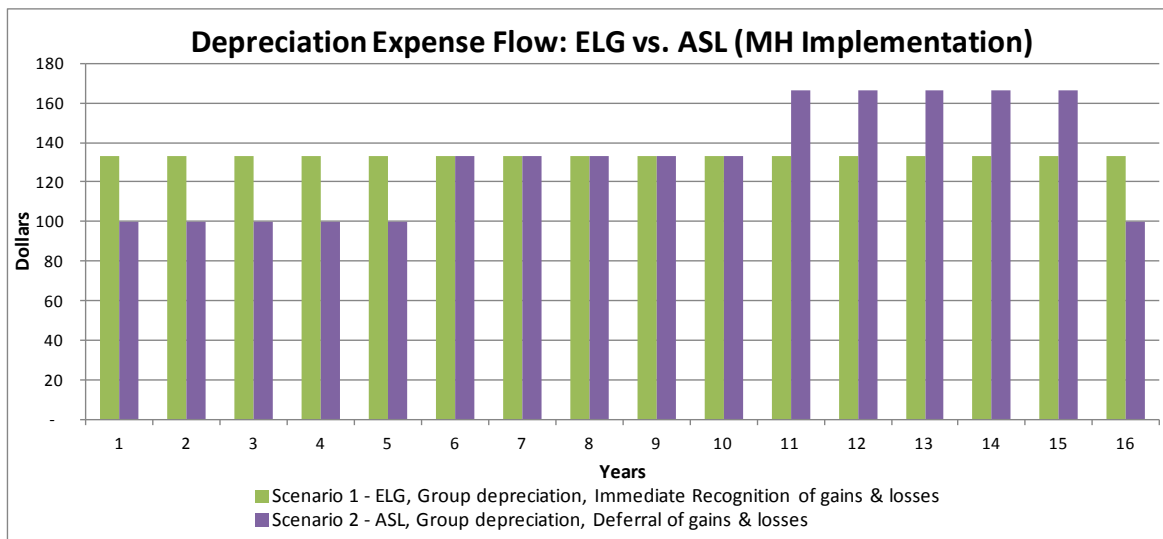
20  
21 Under an ASL scenario where gains and losses are deferred and depreciation studies are  
22 carried out periodically (assumed every 3 years in the above scenario), the account will be  
23 found to have a significant accumulated depreciation deficit at the first depreciation study,

1 resulting in a significant upward adjustment to depreciation rates, followed by further  
2 depreciation rate adjustments in subsequent studies, and realization of a gain or loss at the  
3 end of life of the asset pool. This methodology results in an overall expense pattern which  
4 bears little resemblance to the assets available for use in each year. As with the prior ASL  
5 scenario, the entire \$100,000 original cost has been charged to ratepayers in the first 5.5  
6 years, and ratepayers in year 10 benefit from a repayment of excess depreciation charges  
7 resulting from the recognition of a gain on retirement of the final assets in the group.  
8

9 In contrast, the ELG method produces a declining depreciation expense pattern which  
10 reflects the varying life spans of the individual assets which make up the pool. As such,  
11 there is no need to refund over-depreciated amounts to ratepayers in the later life of the  
12 asset pool with ELG.  
13

14 When ELG is used for a stable asset pool, where individual parts are replaced when they  
15 reach end of life, as is common for utility assets, ELG delivers an equal amount of expense  
16 each year throughout the life of the pool. Assuming the asset in question generates the  
17 same level of output over its service life, charging customers with an equal depreciation  
18 expense each year satisfies the concept of intergenerational equity. In contrast, applying  
19 ASL to the same group with the deferral of gains and losses results in an increasing  
20 expense pattern. The following chart provides a comparison of the depreciation expense  
21 generated under each scenario. Supporting calculations for the scenarios illustrated in this  
22 chart (Figure 5) may be found in Attachment B:  
23  
24

Figure 5



1 Mr. Bowman argues that this increasing expense pattern is appropriate for a hydro  
2 dominated utility as the profitability of hydraulic generation assets increases over time.  
3 Manitoba Hydro contends that the profitability of a hydraulic generating station is  
4 dependent on a number of variables such as future electricity prices, exchange rates and  
5 water levels. All such variables occur and are influenced by factors completely  
6 independent of the physical operations of the generating station and should thus, not be the  
7 determining factor in the selection of the station's depreciation rates. Manitoba Hydro is  
8 not aware of any utility that uses a depreciation method intended to match depreciation  
9 expense to profitability. Any attempt to match depreciation expense flows to profitability  
10 would require ongoing adjustments to depreciation rates as other forecast variables  
11 changed, which would introduce a significant level of volatility, and as such, could not be  
12 considered to be either a rational or a systematic method of depreciation.

13  
14 While Mr. Bowman contends that the ELG approach is inconsistent with the spirit and  
15 intent of IAS 16, Manitoba Hydro would like to point out that the IASB issued an exposure  
16 draft on December 4, 2012 which clarifies that: "A method that uses revenue generated  
17 from an activity that includes the use of an asset is not an appropriate depreciation method  
18 for that asset, because it reflects a pattern of the future economic benefits being generated  
19 from the asset, rather than a pattern of consumption of the future economic benefits  
20 embodied in the asset" (Proposed Amendments to IAS 16, paragraph 62A).

21  
22 The primary function of Manitoba Hydro's assets is to ensure an adequate and continuing  
23 supply of electricity for domestic customers. Any profit resulting from the export of excess  
24 power is reflected as a direct benefit to domestic customers as it is earned.

25  
26 While Mr. Bowman's evidence primarily concentrates on generating assets, Manitoba  
27 Hydro notes that hydraulic generation assets comprise only 38% of the total asset base as  
28 at March 31, 2012.

29  
30 Manitoba Hydro's proposed change to the ELG procedure is the preferred alternative for  
31 both financial reporting and rate-setting purposes as it improves inter-generational equity  
32 by matching the amortization of cost, to the life of the assets in use, ensuring that each  
33 generation of ratepayers is charged only for assets of benefit to that generation.

34  
35

1 **2.2.3 Manitoba Hydro's Proposed Change to ELG is Appropriate for an Electric**  
2 **Utility**

3  
4 Mr. Bowman's evidence states that ELG is not well suited to Manitoba Hydro's operations  
5 and that no other Canadian Crown utility nor hydro-dominated utility is cited as making  
6 use of the ELG approach. This includes the following Canadian utilities as set out in  
7 Attachment C, Table C-1 of Mr. Bowman's evidence: BC Hydro and BC Transmission and  
8 Corporation; Newfoundland and Labrador Hydro; Northwest Territories Power  
9 Corporation; Qulliq Energy Corporation; SaskPower and Yukon Energy Corporation.

10  
11 It should be noted that the nature and level of component breakdown varies between  
12 utilities, and that the larger Crown Utilities cited in Mr. Bowman's evidence have  
13 implemented ASL differently than Manitoba Hydro, in that they have divided their  
14 depreciable assets into a much more granular set of components and use a 'unit'  
15 accounting rather than a 'group' accounting depreciation approach. For Newfoundland and  
16 Labrador Hydro, this is confirmed in the latest negotiated settlement agreement referenced  
17 by Mr. Bowman. The increased level of componentization is evident from a review of the  
18 BC Hydro<sup>2</sup> and the Newfoundland and Labrador Hydro<sup>3</sup> documents referred to in Mr.  
19 Bowman's evidence. It is Manitoba Hydro's understanding that SaskPower and Hydro  
20 Quebec also use ASL with a unit accounting depreciation methodology.

21  
22 Due to the differences in implementation approach, the depreciation expense recorded by  
23 Manitoba Hydro using a group accounting approach under ASL (Scenario 2) is not directly  
24 comparable with that of entities using a unit accounting approach under ASL (Scenario 3).  
25 Manitoba Hydro's proposed use of ELG (Scenario 1) produces results that are more  
26 consistent with that of utilities which use ASL in a unit accounting approach. The  
27 following chart provides a comparison of the relevant scenarios. Supporting calculations  
28 for the scenarios illustrated in this chart (Figure 6) may be found in Attachment B:

29  
30  

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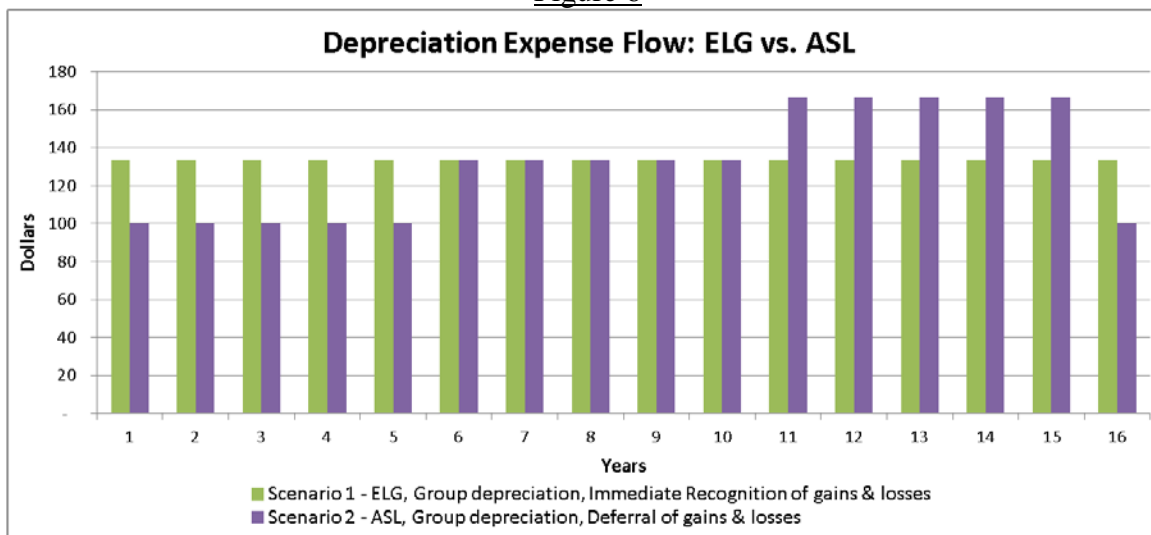
<sup>2</sup> BC Hydro and Power Authority F2012 - 2014 Revenue Requirements Application; Appendix G: Review of  
BC Hydro's Implementation of International Financial Reporting Standards by Gannett Fleming. Pages 14-  
20 (January 24, 2011).

[http://www.bchydro.com/etc/medialib/internet/documents/planning\\_regulatory/rev\\_req/amended\\_bch\\_f12\\_f14\\_rra\\_appendices.Par.0001.File.amended\\_bch\\_f12\\_14\\_rra\\_appendices.pdf](http://www.bchydro.com/etc/medialib/internet/documents/planning_regulatory/rev_req/amended_bch_f12_f14_rra_appendices.Par.0001.File.amended_bch_f12_14_rra_appendices.pdf)

<sup>3</sup> Newfoundland and Labrador Hydro Depreciation Study. Pages III-4 & III-5 (September 7, 2011)  
<http://www.pub.nf.ca/applications/NLH2012Depreciation/files/applic/NLH2012DepreciationApplication.pdf>

1

Figure 6



2

3

4

While Manitoba Hydro could implement a level of componentization at a much more granular level together with use of an ASL depreciation methodology, the increased administrative costs would have to ultimately be borne by customers and this is unnecessary as comparable results can be achieved with use of ELG as proposed by Manitoba Hydro.

9

10 **2.2.4 Changes to Manitoba Hydro’s Depreciation Methodology are required for**  
 11 **IFRS Compliance**

12

13

Mr. Bowman’s evidence claims that Manitoba Hydro has overstated the degree to which accounting standards are driving the changes that have been proposed by the Corporation. Under IFRS, per IAS 16, Property Plant and Equipment is treated as follows:

16

17

*43 Each part of an item of property, plant and equipment with a cost that is significant in relation to the total cost of the item shall be depreciated separately.*

19

20

*45 A significant part of an item of property, plant and equipment may have a useful life and a depreciation method that are the same as the useful life and the depreciation method of another significant part of that same item. Such parts may be grouped in determining the depreciation charge.*

24

25

*46 To the extent that an entity depreciates separately some parts of an item of property, plant and equipment, it also depreciates separately the remainder of the item.*

26

1        *The remainder consists of the parts of the item that are individually not significant. If*  
2        *an entity has varying expectations for these parts, approximation techniques may be*  
3        *necessary to depreciate the remainder in a manner that faithfully represents the*  
4        *consumption pattern and/or useful life of its parts.*

5  
6        Either ASL or ELG can be employed by an entity in a manner that is IFRS compliant, but  
7        the implementation details must differ depending on the methodology employed.

8  
9        The ELG procedure specifically considers the expected service life of each individual asset  
10       in the calculation of the desired annual depreciation charge and depreciation rate. As such,  
11       it embodies the necessary estimation techniques to allow for grouping of assets with  
12       differing expected service lives.

13  
14       The ASL procedure uses an averaging approach, and as such, it is necessary to define  
15       depreciable components quite narrowly in order to meet the IFRS requirement that a group  
16       of assets is depreciated in a way that appropriately reflects the useful life of the included  
17       parts. For Manitoba Hydro, an IFRS compliant ASL implementation would require a  
18       significantly greater degree of componentization in order to segregate parts with longer or  
19       shorter expected lives than the average.

20  
21       **2.2.5 There is No Need for a Separate Set of Regulatory Financial Statements Under**  
22       **the Cost of Service Rate Setting Methodology**

23  
24       Mr. Bowman's evidence contends that Manitoba Hydro has not pursued or identified any  
25       options in the current filing to mitigate the rate impacts of the accounting changes that  
26       have been made to date or are expected upon the transition to IFRS. Mr. Bowman  
27       acknowledges that Manitoba Hydro has limited options in terms of financial reporting  
28       frameworks other than IFRS, but goes on to recommend that in the event that rate-  
29       regulated accounting is not allowed for financial reporting purposes that Manitoba Hydro  
30       should provide the PUB with "regulatory" statements and calculations as an alternate to the  
31       IFF to assess rate requirements. Mr. Bowman suggests that such regulatory statements  
32       would provide for the following for rate-setting purposes:

- 33       • DSM expenditures would continue to be deferred and amortized;  
34       • Overhead capitalization practices for the 2008-2010 period would continue;  
35       • Net salvage from depreciation would be eliminated  
36       • The Average Service Life method of depreciation would continue



- 1 • Long-term debt for projects not in service and AOCI be removed from the  
2 Debt:Equity ratio.

3  
4 Mr. Bowman's assertion that Manitoba Hydro has not pursued any mechanism to mitigate  
5 the rate impacts of accountings changes is not correct. Manitoba Hydro has reviewed its  
6 financial reporting options but has limited options given that Public Sector Accounting  
7 Board (PSAB) standards require that government related business enterprises such as  
8 Manitoba Hydro adopt IFRS for financial reporting purposes. However, Manitoba Hydro  
9 has been making any changes that are necessary and permitted under CGAAP gradually  
10 over the past number of years in an effort to transition them into customer rates and  
11 moderate the impact on customers. Manitoba Hydro has deferred the implementation of  
12 IFRS for three successive years as permitted by the AcSB and continues to monitor the  
13 developments at the IASB with respect to rate-regulated accounting to ensure that when it  
14 does transition to IFRS it is with the lowest possible impacts to customers.

15  
16 Mr. Bowman does not appear to recognize that it is not necessary to resort to a separate set  
17 of regulatory financial statements under the cost of service rate setting methodology that is  
18 used to set electric rates in Manitoba. Unlike the rate base/rate of return methodology that  
19 is used to set rates in other jurisdictions, the cost of service approach used in Manitoba  
20 does not determine rates based strictly on changes in costs and an established capital  
21 structure and return on equity. Rather the cost of service methodology coupled with  
22 Manitoba Hydro's approach of implementing regular and reasonable rate increases has the  
23 flexibility to recognize changes in costs and levels of retained earnings and transition these  
24 changes into rates gradually over time.

25  
26 The success of this approach is evidenced by the fact that despite significant decreases in  
27 net extraprovincial revenues and increases in costs due to accounting changes that have  
28 been forecast between IFF09 and IFF12, Manitoba Hydro has maintained the required rate  
29 increases at around the 3.5% level in the Test Years. This demonstrates Manitoba Hydro's  
30 continued commitment to utilize a cost of service rate setting methodology with regular  
31 and reasonable rate increases to ensure the maintenance of an adequate financial structure  
32 over the long-term. These approaches serve to protect customers from sudden or large rate  
33 increases and make a separate set of regulatory financial statements unnecessary.

34  
35 Manitoba Hydro observes that Mr. Bowman evaluates each of the proposed accounting  
36 changes in isolation and adopts those that decrease costs while rejecting changes that  
37 increase costs as not being consistent with the hydro-electric business. In contrast,

1 Manitoba Hydro has a more balanced approach to this issue and has evaluated the overall  
 2 changes that result from the implementation of IFRS and resulting impacts on rates. The  
 3 following table (Figure 7) summarizes the projected impact of the transition to IFRS on  
 4 electric operations balance sheet and income statement in 2014/15 in IFF12:

5  
 6 Figure 7

**IFRS Impacts - Electric Operations  
 Increase / (Decrease)**

(Millions of \$)	Retained Earnings at April 1, 2014	Net Income 2014/15
Power Smart Programs	(172)	7 *
Site Remediation	(32)	(1) *
Acquisition (Centra & Manitoba Hydro)	(19)	1 *
Regulatory Costs	(2)	1 *
Capital Taxes	-	3
Administrative Overhead and Other	(36)	(36)
Pension & Employee Benefits	(21)	4
Removal of Net Salvage Depreciation	60	63
Change to Equal Life Group Depreciation	<u>(34)</u>	<u>(36)</u>
Total IFRS Impact	<u><b>(257)</b></u>	<u><b>5</b></u>

\*Net income amounts for rate-regulated accounts include the additional operating &  
 administrative expense net of the offsetting reduction to amortization expense.

7  
 8  
 9 As the table demonstrates, the impact on electric net income of all of the proposed changes  
 10 is minimal and will not impact the required electric rate increases. While the impact on  
 11 retained earnings in the year of transition is more significant, this can be accommodated  
 12 within the cost of service rate setting methodology without the need for near-term  
 13 compensating rate increases. The response to PUB/MH I-78(b) demonstrates that the debt  
 14 to equity ratio of a scenario that assumes the continuation of rate-regulated accounting  
 15 converges with the MH11-2 forecast which assumed that rate-regulated accounting would  
 16 be discontinued, within a ten year period to 2021/22. This demonstrates that the transition  
 17 to IFRS will only result in timing differences with respect to the recognition of costs. The  
 18 write-off of rate-regulated accounts will have minimal impact on cumulative retained  
 19 earnings once the 10 year amortization period has elapsed. The transition to IFRS should  
 20 not trigger the requirement for a separate set of regulatory financial statements for rate-  
 21 setting purposes.

22  
 23 One of the benefits of the cost of service rate setting methodology employed in Manitoba  
 24 is that the PUB uses the same set of general purpose financial statements and information

1 to set rates as Manitoba Hydro, the Manitoba Hydro-Electric Board and other external  
2 users of the statements (such as credit rating agencies) for their purposes. This reduces the  
3 potential confusion associated with different users looking at multiple sets of financial  
4 information to make decisions, evaluate financial performance and assess rate  
5 requirements and improves the transparency of the rate setting process by aligning the  
6 basis used to set rates and report results. As an example to support this view, one need  
7 look no further than Mr. Bowman's recommendation to remove the long-term debt  
8 associated with new generation projects that are not yet in service from the debt to equity  
9 ratio calculation. Mr. Bowman's proposed calculation is theoretical in nature and could  
10 result in the PUB having a very different assessment of the financial position of the  
11 Corporation than any other user of the financial statements. Given that one of the purposes  
12 of regulation is to ensure the financial integrity of the utility for the benefit of the  
13 ratepayer, having such a theoretical calculation that reflects only a portion of the  
14 Corporation's operations is at best confusing and potentially misleading.

15  
16 In addition, there is significant administrative costs associated with reconciling between  
17 the different sets of financial information and maintaining duplicate transactional  
18 accounting that would be necessary to produce reliable and complete regulatory reporting.  
19 This would simply add to the regulatory compliance costs that customers ultimately must  
20 bear without any additional benefit to them.

### 21 22 **3.0 DEMAND SIDE MANAGEMENT**

#### 23 24 **3.1 Manitoba Hydro's Demand Side Management Activities**

25  
26 In this section Manitoba Hydro addresses the evidence of Mr. Phillippe U. Dunsky and Mr.  
27 Paul Chernick with respect to Manitoba Hydro's Demand Side Management (DSM)  
28 activities. Mr. Dunsky's evidence suggests that Manitoba Hydro's DSM efforts are modest  
29 compared to those of many other North American jurisdictions (page 44) and that  
30 Manitoba Hydro is abandoning its energy efficiency efforts based upon decreasing DSM  
31 targets over the next 15 years as presented within Manitoba Hydro's Power Smart Plan.  
32 Mr. Dunsky's analysis is primarily based on a comparison of Manitoba Hydro's DSM  
33 efforts to other efforts being made in North America using a savings ratio metric. Mr.  
34 Chernick comments that Manitoba Hydro should adopt the Total Resource Cost (TRC) or a  
35 modified TRC test in program design and cost effectiveness screening (page 49) as  
36 Manitoba Hydro's current approach is limiting DSM in Manitoba.

1 Contrary to Mr. Dunsky's characterization, Manitoba Hydro continues to be a recognized  
2 leader in energy conservation and the Corporation continues to be committed to pursuing  
3 available energy efficient opportunities which are economic. Evidence of Manitoba  
4 Hydro's reputation is exemplified by the following:

- 5 • International Energy Association – Manitoba Hydro's Power Smart Residential  
6 Loan was selected to be included as a Canadian example of best practice in an  
7 upcoming report as a result of the International Energy Agency's international  
8 review of innovative and exemplary energy efficiency programs (Interview  
9 completed in June 2012).
- 10 • Natural Resources Canada Office of Energy Efficiency – Manitoba Hydro was  
11 asked to present the Power Smart Residential Loan Program for a nationwide  
12 webinar for on-bill financing (January, 2012).
- 13 • Ontario Geothermal Association – Manitoba Hydro was invited as a guest speaker  
14 to highlight Power Smart's long history with the geothermal industry including  
15 present day programs as well as the strategies employed early in the adoption cycle  
16 of geothermal to assist the industry in ensuring the technology as a viable heating  
17 alternative in the Manitoba market (November, 2011).
- 18 • Numerous consultations on commercial and residential Power Smart program  
19 design and marketing with other utilities and governments including SaskPower,  
20 Hydro Quebec, Efficiency New Brunswick, BC Hydro, Newfoundland and  
21 Labrador Hydro, Xcel Energy, City of Toronto, Ontario Ministry of Energy,  
22 ESource, Baltimore Gas and Electric and Climate Change Central. Manitoba  
23 Hydro's expertise has been sought for several of its leading edge programs  
24 including Commercial Building Optimization, Commercial New Construction, CFL  
25 School Program, Commercial Refrigeration, Fridge Retirement Program, Water  
26 and Energy Saver Program and several more.

27 Manitoba Hydro agrees that using a savings ratio metric in general is valid for comparing  
28 energy conservation efforts between regions with similar load characteristics and having  
29 similar marginal cost considerations. However the savings ratio metric can produce  
30 misleading conclusions when comparing DSM efforts with regional load differences and  
31 significant marginal cost differences. In the report "Leadership in Energy Efficiency –  
32 Comparing Manitoba Hydro's Power Smart with Leading North American Strategies"  
33 undertaken in 2009, Mr. Dunsky cautions that conclusions drawn from benchmarking must  
34 be done in consideration of varying load and regional differences; and that conclusions

1 should not be drawn solely upon benchmark metrics as it may lead to misleading and  
2 ambiguous results<sup>4</sup>.

3 Manitoba Hydro recognizes Mr. Dunsky's attempt to find comparison regions that would  
4 reflect similar constructs as Manitoba. However, Manitoba Hydro would assert that in his  
5 selection Mr. Dunsky is oversimplifying the influence of market differences and has  
6 understated of the influence of the combined effects of these and other market  
7 characteristics. Manitoba Hydro believes it is important to recognize the influence of these  
8 market differences. To demonstrate this, Mr. Dunsky states on page 20 of his evidence that  
9 "climate doesn't appear to be a determining factor as far as planned DSM savings are  
10 concerned" and that "while it is true that Manitoba, with the harshest climate, has the  
11 lowest savings ratio by far, B.C., with the mildest climate in the group, has the second-  
12 lowest savings ratio". He later states in his response to PUB/CAC & GAC 9 (c) that "the  
13 average residential GWh load in Minnesota is slightly lower than that in BC, despite  
14 Minnesota being nearly twice as cold as BC". Mr. Dunsky also states that penetration of  
15 electric space heating is an important factor but does not investigate further as possibly  
16 influencing the outcomes for BC and Minnesota. We would note that although Minnesota  
17 is nearly twice as cold as BC, the percentage of residential customers with electric heat is  
18 half of that in BC (15% in MN versus 31% in BC). Based upon this, one would expect that  
19 Manitoba having the harshest climate (4517 DDH) combined with a high percentage of  
20 electric space heating (42%) would potentially influence the metrics.

21  
22 Manitoba Hydro recognizes that some regions are pursuing higher levels of energy savings  
23 than what is being planned under the Corporation's 2011 Power Smart Plan. Manitoba  
24 Hydro notes that this reflects regional differences (i.e. each region has different marginal  
25 cost values, different economic energy efficient opportunities and different policies driving  
26 DSM efforts). In a number of cases, the marginal cost in a region is much higher than  
27 Manitoba Hydro's marginal cost and as such, it is expected that these regions will have  
28 significantly more economic opportunities. Manitoba Hydro's Power Smart Plan is based  
29 on its unique situation of:

- 30 – having a marginal cost value which is considerably lower than regions such as  
31 British Columbia, Nova Scotia and Vermont;
- 32 – having a marginal cost value where the export electricity market accounts for a  
33 significant component of the marginal cost value (i.e. as opposed to deferred new

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<sup>4</sup> "Leadership in Energy Efficiency – Comparing Manitoba Hydro's Power Smart with Leading North American Strategies", a Dunsky Energy Consulting report commissioned by Manitoba Hydro, October 1, 2009, page 27.

1 generation costs);

- 2 – having a load characteristic consisting of a large diverse industrial load, significant  
3 electricity use for space and water heating, and high heating degree days.  
4

5 Manitoba Hydro recognizes that DSM targets presented in the 2011 Power Smart Plan are  
6 declining but would assert that this is a reflection of Manitoba Hydro's, consistent long  
7 term engagement in DSM and the diminishing availability of economic energy efficient  
8 opportunities remaining in the Manitoba market. Manitoba Hydro agrees with aggressively  
9 pursuing energy efficiency opportunities; however, the Corporation believes it is important  
10 to primarily pursue those opportunities which are economic.  
11

12 There are two high level processes undertaken in developing an overall DSM program: a  
13 screening process and a program design process. The screening process is generally  
14 undertaken without consideration for who benefits and who pays the costs. This screening  
15 exercise is undertaken to identify economic energy efficient opportunities. It is appropriate  
16 to use either the Marginal Resource Cost (MRC) test, a modified Total Resource Cost  
17 (TRC) test or Societal Cost Test (SCT) for this purpose. Once the economic DSM  
18 opportunities are identified, then a separate exercise is undertaken to determine which  
19 program design is best to pursue in support of the DSM opportunity.  
20

21 Manitoba Hydro uses the MRC test which is a simplified version of the TRC test; however  
22 program administration costs are excluded under the MRC test. As such, the MRC test  
23 will "screen in" more opportunities than a TRC test. Similarly, a SCT test will "screen in"  
24 more opportunities than a TRC test as the SCT includes additional benefits, many of which  
25 are very difficult to measure (e.g. comfort). Given program administration costs (i.e. those  
26 costs which are excluded in a MRC test) can be a significant component of an overall  
27 Power Smart budget, Manitoba Hydro is of the view that the use of a MRC test for  
28 screening energy efficient opportunities effectively achieves the same result as using a  
29 SCT. Further, Manitoba Hydro

- 30 – includes measureable non electricity benefits such as water savings within the  
31 MRC;  
32 – includes the value of GHG emissions (i.e. this value is included within the forecast  
33 price of electricity to be sold in the export market; the value of export electricity  
34 makes up a significant component of Manitoba Hydro's avoided cost); and  
35 – considers any opportunities which may be close to passing the MRC so the use of  
36 this test is not a hard "go/no-go" decision.  
37

1 In the program design process, a number of metrics (the modified TRC test, Levelized  
2 Utility Cost (LUC) test, participant payback period and Rate Impact Measure (RIM) test)  
3 are used in aggregate to determine which program design will be most appropriate to  
4 undertake. The simple participant payback metric provides a high level indication of the  
5 economic benefit for a DSM option for an eligible customer. To assess the impact to the  
6 utility (i.e. ratepayer), Manitoba Hydro uses both the RIM and the LUC metrics.

7  
8 The RIM test is a simple test which provides an indication of the directional impact and the  
9 general magnitude DSM programs have on rates, recognizing the latter is very  
10 rudimentary. If the RIM test is equal or close to one, then non-participants are relatively  
11 indifferent economically.

12  
13 The LUC metric provides a more useful measure of the relative value or cost to the utility  
14 (and all rate payers) as this measure provides a unit cost for achieving the energy savings.  
15 This measure is generally used to compare the impact of DSM programs to the marginal  
16 cost less the lost domestic revenue (i.e. real economic impact to the utility (ratepayer)).  
17 Due to the complexity of Manitoba Hydro's marginal cost value, Manitoba Hydro  
18 emphasizes that caution must be exercised in using the LUC at face value. Manitoba  
19 Hydro's annual marginal value is an average of the underlying values which vary between  
20 seasons and between on-peak and off-peak time. Further, the marginal value is composed  
21 of both demand and energy values. For this reason, it is critical that Manitoba Hydro use  
22 both the RIM test in conjunction with the LUC test in assessing the real economics of each  
23 DSM option.

24  
25 In the response to PUB/CAC & GAC 14, Mr. Dunsky is suggesting that in the absence of  
26 DSM efforts, ratepayers would need to spend the difference between Manitoba Hydro's  
27 avoided cost (i.e. 8.5 cents/KWh) and the levelized cost of achieving DSM savings (e.g.  
28 1.5 cents/KWh) which is 7.0 cents/KWh. Mr. Dunsky's analysis excludes critical factors  
29 which leads to a misrepresentation of the true costs to ratepayers of reducing utility  
30 spending in DSM.

31  
32 To assess the cost to the ratepayer, all benefits and costs must be considered. The  
33 following analysis (Figure 10) presents the net costs of reduced DSM spending to the  
34 utility (ratepayer), participating customers and from an integrated resource perspective  
35 using the model utilized by Mr. Dunsky in his response to PUB/CAC & GAC 14 (note:  
36 assumptions include having a marginal cost of 8.5¢/kWh, a DSM LUC of 1.5¢/kWh, a  
37 domestic rate of 7¢/kWh. and a participant DSM contribution of 3.3¢/kWh)

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Figure 8

<b>Utility Perspective (Ratepayer)</b>	<b>Unit Cost</b>
Reduction in DSM Spending (Utility)	(1.5 ¢/kWh)
Utility Lost Opportunity Cost	
Lost Opportunity Marginal Value of Electricity	8.5 ¢/kWh
Inflow Revenues	<u>(7.0 ¢/kWh)</u>
Net Utility Lost Opportunity	1.5 ¢/kWh
Net Cost to Ratepayers of reducing DSM Spending	<b>0.0 ¢/kWh</b>
<b>Participating Customer Perspective</b>	<b>Unit Cost</b>
Reduction in DSM Spending (Participating Customer)	(3.3 ¢/kWh)
Utility Bill Impact (lost opportunity of avoided utility bill) <sup>2</sup>	<u>7.0 ¢/kWh</u>
Net Cost to Participating Customer of reducing DSM Spending	<b>3.7 ¢/kWh</b>
<b>Integrated Utility/Customer Perspective (Total Resource Cost)</b>	<b>Unit Cost</b>
Reduction in DSM Spending (Utility)	(1.5 ¢/kWh)
Reduction in DSM Spending (Participating Customer)	( 3.3 ¢/kWh)
Lost Opportunity Marginal Value of Electricity	<u>8.5 ¢/kWh</u>
Net Integrated Resource Cost of reducing DSM Spending	<b>3.7 ¢/kWh</b>

By taking a comprehensive analysis, it is clear that the utility (i.e. the ratepayer) is economically indifferent and the participating customer is worse off by not implementing the DSM measure by 3.7 ¢/kWh. In this case, the eligible customer has a significant incentive to participate in the DSM opportunity. Although the overall analysis is crude, the general message is clear and consistent with Manitoba Hydro’s assessment of its Power Smart Plan. Based on this analysis, it is evident that pages 34-35 and 38 of Mr. Dunsky’s direct testimony, page 27 of Mr. Chernick’s direct testimony and responses to PUB/CAC & GAC 18 and PUB/GAC 12(a) are similarly misleading.

In both Mr. Dunsky’s and Mr. Chernick testimony (page 33 and pages 23-25 & 32, respectively) and in responses to PUB/CAC & GAC 16, and PUB/GAC 10, it is suggested that Manitoba Hydro is not using the appropriate tests in screening its DSM programs. Manitoba Hydro would assert that the Corporation is using the DSM metrics appropriately



1 and maintains that all of the metrics used in the development of the Power Smart Plan are  
2 both useful and valuable in designing efficient and effective programs. Mr. Chernick's and  
3 Mr. Dunsky's comments appear to be a result of not fully understanding how and when  
4 Manitoba Hydro uses each of the DSM metrics. For example and as previously stated,  
5 Manitoba Hydro does not use the RIM test to screen DSM opportunities. Further the MRC  
6 test is a reasonable and can be a more inclusive test relative to the modified TRC and SCT  
7 for screening purposes.

8  
9 Contrary to Mr. Chernick's testimony, the RIM test is a valuable metric for Manitoba  
10 Hydro in assessing the economics of its DSM programs from a utility/ratepayer  
11 perspective. Manitoba Hydro does not screen out energy efficient opportunities using  
12 either the RIM or the LUC Test. These tests are only used by Manitoba Hydro to assist in  
13 program design decisions including how aggressive to pursue a particular opportunity.

14  
15 Manitoba Hydro agrees with Mr. Dunsky's suggestion that the Corporation's Power Smart  
16 Plan is conservative in the sense that only identified economic opportunities have been  
17 included. Manitoba Hydro recognizes that some new opportunities will likely surface in  
18 the future and the Corporation intends to include these opportunities once they are  
19 identified as being economic within the Manitoba market.

20  
21 Manitoba Hydro's 2011 Power Smart Plan involves pursuing all energy efficient  
22 opportunities which have been identified as being economic in Manitoba. In an effort to  
23 identify additional opportunities, Manitoba Hydro is currently in the process of  
24 undertaking a DSM market potential study. The results of this study will be used as a basis  
25 for developing Manitoba Hydro's future DSM plans. In addition, with the passing of the  
26 Energy Savings Act, Manitoba Hydro will be consulting with the Minister responsible for  
27 Manitoba Hydro in establishing future DSM targets.

28  
29 To ensure Manitoba Hydro's approach to setting targets is aligned with available  
30 opportunities, the Corporation also monitors leading utilities and the programs being  
31 offered by these utilities throughout North America. The results of these comparisons  
32 demonstrate that, Manitoba Hydro has a comprehensive and aggressive energy  
33 conservation effort. For example, a review of the utilities presented by Mr. Dunsky has  
34 found numerous similarities within the DSM portfolios offered in the residential,  
35 commercial and industrial sectors.

36  
37

1 The following table (Figure 9) compares DSM offerings for residential markets.

2

3

Figure 9

<b>Residential Programs/Offerings</b>	<b>Manitoba Hydro</b>	<b>Quebec</b>	<b>British Columbia</b>	<b>Nova Scotia</b>	<b>Mass.</b>	<b>Minn.</b>	<b>Vermont</b>
Building Envelope	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Water Heat/Conservation	Yes	No	Yes	Yes	Yes	Yes	No
Lighting	Ended	Yes	Yes	Yes	Yes	Yes	Yes
New Construction	Redesign underway	Yes	Yes	Yes	Yes	Yes	Yes
Appliances	Ended	No	Yes	Yes	Yes	Yes	Yes
Appliance retirement	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Financing	Yes	No	Yes -pilot	Yes – 3rd party	Yes	No	No
Energy Audits	Yes	Yes	Yes	Yes	Yes	Yes	Yes
HVAC	Financing	Yes	Yes	Yes	Yes	Yes	Yes
Lower Income	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Geothermal	Yes	Yes	Yes	Yes	No	Yes	No
Solar Thermal	Financing	No	Yes	Yes	Financing	Yes	No
TVs/Electronics	No	No	No	No	Yes	No	No
Swimming Pool Pump	No	Yes	No	No	Yes	No	Yes
Electricity Meter Loan	No	No	No	No	No	No	Yes
Fuel switching to natural gas or biomass	No	No	No	Yes	No	No	Yes
Programmable Thermostats	Ended	Yes	Yes	Yes	Yes	No	No
Solar Photovoltaic Systems	No	No	No	No	No	Yes	No
School Education	Yes	No	No	No	Yes	Yes	Yes

4

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7

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9

Based on this comparison, it is evident that Manitoba Hydro is pursuing a comprehensive list of energy efficient opportunities within the residential market. Further, Manitoba Hydro continues to explore and evaluate additional opportunities which could be pursued (e.g. LED lighting is currently being assessed for future opportunities).

1 The following table (Figure 10) compares DSM offerings for commercial markets.

2

3

Figure 10

<b>Commercial Programs/Offerings</b>	<b>Manitoba Hydro</b>	<b>Quebec</b>	<b>British Columbia</b>	<b>Nova Scotia</b>	<b>Mass</b>	<b>Minn.</b>	<b>Vermont</b>
New Construction	Yes	Yes	Yes	Yes	No	Yes	Yes
Lighting	Yes	Yes	Yes	Yes	Yes	Yes	Yes
HVAC	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Building Envelope - Retrofit	Yes	Yes	No	No	Yes	Yes	Insulation only
Appliances	Yes	No	Yes	Yes	Yes	Yes	No
Refrigeration	Yes	Limited to refrigerant reduction/ change, or heat reclaim	Yes	Yes	Limited	Limited	Yes
Custom Opportunities	Yes	Gas only	Yes	Limited	Yes	Yes	No
Heat Pumps (geothermal and air-source, etc)	Yes	No	Limited, demo only.	Limited	Yes	Water source only.	No
Information Technology	Yes	No	No	No	No	Yes	No
Retrocommissioning & Recommissioning	Yes	No	Limited, investigation only.	No	Yes	Yes	No
Energy Management	Redesign underway	No	Yes	No	No	Limited	No
Targeting Small Business	Redesign underway	No	No	Yes	Yes	Yes	No
Financing	Limited. PAYS in Design	Limited, demo only.	Limited	Yes	Yes - 3rd party	Yes	Yes
Energy Audits	Limited	No	Limited to largest customers	Limited	Limited	Yes	Yes
Building Certification	Yes	No	No	No	No	Yes	No
Variable Speed Drives, Efficiency Controls	Yes-Custom	No	Custom	VSD only	Yes	Yes	No
Solar	Yes-Custom	Yes	No	Yes	Custom	Yes	Yes
Agricultural	Limited	No	Limited	Limited	No	Limited	No
Compressed Air	Yes	No	No	No	Yes	No	No
Pumps and Motors	Yes	No	Pump assessment only	No	Motors only	No	No
Ice and Curling Rinks	Yes-Custom	Yes	Yes	No	No	No	No

1 Based on this comparison, it is evident that Manitoba Hydro also is pursuing a  
2 comprehensive list of energy efficient opportunities within the commercial market. Similar  
3 to the residential market, Manitoba Hydro continues to explore and evaluate additional  
4 opportunities which could be pursued in the commercial market (e.g. commercial PAYS  
5 financing to assist in hard to reach targeted market sectors such as multi-residential,  
6 institutional and small commercial).

7  
8 For the industrial sector, a broad comparison indicates that Manitoba Hydro's Power Smart  
9 program targets similar opportunities to those being pursued in the six jurisdictions  
10 referenced in the previous tables. Manitoba Hydro's industrial DSM efforts provide  
11 financial incentives for feasibility studies. Opportunities are pursued for all technologies  
12 that contribute verifiable electric and natural gas savings. Technologies that have been  
13 supported to date include; variable frequency drives, compressed air systems upgrades,  
14 energy management systems, refrigeration, HVAC, heat pumps, energy recovery, boilers,  
15 hi-efficiency motors, building envelope upgrades, steam trap assessments, process  
16 equipment and pipe insulation.

17  
18 On page 24 of Mr. Dunsky's written testimony, he agrees that sustained high levels of  
19 savings are a challenge; however Mr. Dunsky testifies that other technologies will emerge  
20 to create new opportunities. Mr. Dunsky states "At the same time that codes and standards  
21 are being adopted and the potential of some existing measures are being depleted, new  
22 technologies and program approaches are creating new opportunities to replenish the DSM  
23 pool. For instance, while the potential for traditional water heater measures (blankets,  
24 insulation, low-flow showerheads) have largely dried up due to the success of past DSM  
25 programs and standards, new measures are taking their place, including gray water heat  
26 recovery, heat pump water heaters, and solar water heaters." Further in his testimony (page  
27 35 -36), Mr. Dunsky highlights additional opportunities under residential lighting through  
28 CFLs and LEDs, the use of ductless heat pumps, particularly newer inverter-driver models,  
29 and the use of bill comparison feedback/benchmarking initiatives. Manitoba Hydro notes  
30 that Mr. Dunsky's recommendations are provided without mention of the cost  
31 effectiveness of these measures from a resource perspective or the applicability to the  
32 Manitoba marketplace.

33  
34 Manitoba Hydro is well aware of the measures mentioned by Mr. Dunsky and these  
35 opportunities have been previously investigated or are being assessed for possible  
36 inclusion in the Corporation's Power Smart plan. For example:

- 1       • Gray water (or drain water) heat recovery is facilitated through Manitoba Hydro's  
2       on-bill financing and is one of the measures being considered as part of the revised  
3       Power Smart New Home standard.  
4
- 5       • Heat pump water heaters are not suited to Manitoba's marketplace. The technology  
6       "pulls" heat out of the space they are located in and "puts" that heat into the water.  
7       This technology is popular in more moderate climates and in regions where the  
8       water heater is not located in a conditioned space. In Manitoba due to our long  
9       heating season, water heaters are located inside our homes and buildings. In  
10      Manitoba Hydro's engineering assessment, energy savings from this application  
11      would be marginal and the conserved energy would not be economic for the  
12      customer or the utility.  
13
- 14      • Solar water heaters are not cost effective in Manitoba under current costs and this  
15      technology is not projected to be cost effective within the near term.  
16
- 17      • In December 2011, Manitoba Hydro discontinued its CFL lighting program after  
18      having a long running and successful CFL in-store incentive program. Through the  
19      Power Smart CFL program, it was estimated that over 65% of Manitoba  
20      households had installed CFLs and it was expected that there would continue to be  
21      additional market penetration without an ongoing incentive program. As such,  
22      Manitoba Hydro's strategy for promoting CFLs changed from offering an incentive  
23      program to a strategy of supporting the energy efficient opportunity through a  
24      customer information campaign. General use LED lamps are not cost effective  
25      under current pricing and a substantial decrease in cost is required before these  
26      measures will be cost effective from a resource perspective. In addition, concerns  
27      about luminous efficacy, validation of the longer life (given short warranties  
28      offered), and proper recycling need to be addressed. Manitoba Hydro promotes  
29      LEDs in the residential sector as part of the customer-information based approach  
30      and continues to monitor the market for potential future opportunities.  
31
- 32      • As outlined in Manitoba Hydro's response to CAC-GAC/MH II-7(c), Manitoba  
33      Hydro is testing the performance of ductless heat pumps. The units have a high  
34      installed cost, estimated to be approximately \$14,000; \$7000 - \$8000 for the unit  
35      plus labour and materials for installing electrical and refrigerant piping and  
36      condensate drain piping throughout a house. Based on Manitoba Hydro's  
37      engineering assessment, the installed cost is not offset by the estimated energy

1 savings from the average home using electric baseboard heating which is 1100 sq.  
2 ft in Manitoba. Based on vendor discussions, to date customers installing these  
3 types of systems reside in larger older homes with natural gas boilers in central  
4 Winnipeg (Wolseley and River Heights areas) and have been purchasing them for  
5 air conditioning; upgrading to the variable flow systems means customers are  
6 essentially switching a portion of their heating requirements to electricity. Based  
7 upon Manitoba Hydro's 2009 Residential Energy Use Survey, customers with  
8 electric baseboard heating systems who have air conditioning (41%),  
9 predominantly install the less costly window air conditioning units (96%).  
10 Manitoba Hydro intends to continue to monitor the performance and costs of air  
11 source heat pumps.

- 12  
13 • Manitoba Hydro has investigated the potential for capturing energy savings through  
14 bill comparison services, including detailed discussions with one North American  
15 service provider. Based upon these discussions, this opportunity was not considered  
16 economic at this time (e.g. the average estimated potential energy savings  
17 associated with this initiative were estimated as having a one year useful life only  
18 with on-going communication and investment to maintain the energy efficient  
19 behaviours). Manitoba Hydro is currently monitoring the results of this  
20 opportunity within other regions and intends to maintain this option as a possible  
21 opportunity to consider in the future.

22  
23 In conclusion, Manitoba Hydro maintains that its Power Smart Plan involves pursuing all  
24 available economic DSM opportunities given consideration to Manitoba's load  
25 characteristics and Manitoba Hydro's marginal values, including the detailed underlying  
26 makeup of the marginal values. Manitoba Hydro remains committed to searching for  
27 additional opportunities and this is evident in the Corporation's ongoing efforts, including  
28 undertaking a market potential study, reviewing efforts and programs being undertaken by  
29 other regions and current efforts assessing potential opportunities (e.g. drain water heat  
30 recovery, LEDs, New Homes). In addition, Manitoba Hydro's use of the MRC is  
31 appropriate for screening potential DSM measures and is a reasonable proxy for using  
32 alternative tests such as a Modified TRC or SCT test. The use of RIM, LUC, and simple  
33 participant payback analyses, in addition to the Modified TRC/SC cost effectiveness tests,  
34 are appropriate metrics for assessing program designs.

35  
36

1 **3.2 Estimate of Environmental Values**

2  
3 In a number of instances, the Direct Testimony of Mr. Chernick suggests that Manitoba  
4 Hydro does not properly recognize the significance of environmental considerations in its  
5 analysis. This is incorrect.

6  
7 For example, at page 19, lines 3-5 of his evidence, Mr. Chernick indicates that Manitoba  
8 Hydro includes the value of reduced greenhouse gas emission for natural gas conservation  
9 but does not include any environmental value for electricity conservation. This is not  
10 correct, nor does it reflect the text of the Power Smart Report that it appears to quote  
11 (Appendix 7.1, Appendix F, page 4).

12  
13 The value of greenhouse gas emissions is included in the evaluation for both natural gas  
14 and electricity DSM programs. The marginal costs for electricity conservation programs  
15 are based on the Export Price Forecast which includes expectations of the value associated  
16 with greenhouse gas emission avoidance in the Midwest region.

17  
18 Mr. Chernick also asserts that it is not reasonable to assume that the sales prices for  
19 Manitoba Hydro's exports reflect the value of carbon emissions (page 19, lines 13-15).  
20 This is also inaccurate. Parties in negotiations for these types of contracts consider what  
21 the electricity prices will be over the life of the contract and must therefore consider all  
22 pricing factors identified above, including expectations of greenhouse gas emission costs.

23 Mr. Chernick states that "the fuel-switching report is entirely a financial analysis without  
24 any valuation of environmental effects" (page 20, lines 5-6). This is incorrect, since the  
25 quantification of greenhouse gas implications of different fuel choices and technologies is  
26 a key focus of this report.

27  
28 **3.3 Accelerated DSM and Need for New Generation**

29  
30 Mr. Dunsky's response to PUB/CAC&GAC 18 comments on the ability to defer Keeyask  
31 to 2031/32 under an accelerated DSM program which yields a savings of 1385 GWhs by  
32 2019/20. Manitoba Hydro disagrees with this statement.

33  
34 Based on the No New Generation System Firm Energy Demand and Dependable Resource  
35 tables in the 2011/12 Power Resource Plan (pages 34-35), additional DSM savings of 1385  
36 GWhs would defer the need for new energy resources until 2024/25 (shortfall of 1651  
37 GWhs). An additional 3000 GWhs would be required to defer the need for new resources

1 to 2031/32 (shortfall of 4400 GWhs).

2  
3 In addition, it is acknowledged in the response provided by Mr. Dunsky to  
4 PUB/CAC&GAC 18, that capacity was not a consideration in deriving the deferral dates.  
5 Based on the 2011/12 Power Resource Plan, new capacity resources are required in  
6 2021/22. To defer this date to 2031/32 would also require in the order of 800 MW of DSM  
7 capacity savings. Mr. Dunsky's evidence does not address if or how these required  
8 capacity savings will be found.

9  
10 **4.0 FUEL SWITCHING REPORT**

11  
12 This section addresses the written evidence of Mr. Paul Chernick on behalf of GAC  
13 regarding Manitoba Hydro's report on the "Economic, Load and Environmental Impacts of  
14 Fuel Switching in Manitoba" (the Fuel Switching Report).

15  
16 Mr. Chernick states on page 32, lines 9-11 of his written testimony that "*Hydro's fuel-*  
17 *switching report indicates a serious market problem, which should be addressed through a*  
18 *combination of rate design, DSM programming and terms and conditions for new and*  
19 *expanded service.*"

20  
21 As Manitoba Hydro outlined in its report "Economic, Load, and Environmental Impacts of  
22 Fuel Switching in Manitoba", there are benefits when customers use natural gas for space  
23 and water heating purposes from the customer, utility, global environmental, and in most  
24 cases of the provincial leakage perspectives. Based on the 2012 Load Forecast, Manitoba  
25 Hydro is projecting a shift overall towards the use of conventional electric space heating  
26 from 34% in 2011/12 to 37% of residential customers in 2030/31. A more significant shift  
27 is expected to occur in fuel use for water heating due to technical and cost considerations  
28 primarily in new homes with electric water heating, which is forecast to grow from 55% of  
29 residential customers in 2011/12 to 79% of residential customers in 2030/31.

30  
31 Manitoba Hydro believes that if customers are well informed, they will make the best  
32 choice for their situation and in most cases will choose natural gas when available. In  
33 September 2012 Manitoba Hydro initiated a Heating Education Campaign to enhance  
34 customers' awareness of factors relevant to their decisions on space and water heating. The  
35 campaign includes a multi-faceted approach targeting homeowners, HVAC suppliers and  
36 installers, homebuilders, commercial builders and property developers. The campaign will  
37 further build in 2013 with the development of new online resources, which can be accessed



1 through Manitoba Hydro's website and social media networks. Advertising in local  
2 newspapers, brochures and bill inserts will be ongoing. Manitoba Hydro also has  
3 convenient financing programs, including the PAYS program, which can assist customers  
4 choosing to replace or upgrade their space and water heating systems.

5  
6 Manitoba Hydro will continue monitoring market trends in fuel choices and will assess the  
7 impact of its educational efforts on an ongoing basis. The Corporation's educational efforts  
8 will be adjusted accordingly and further considerations may be given to using additional  
9 intervention tools such as service extension policies, rate design and incentive programs.

## 10 11 **5.0 MARGINAL COST ESTIMATES**

12  
13 This section deals with the marginal cost evidence provided by Mr. Chernick on behalf of  
14 GAC. Specifically, it addresses Mr. Chernick's assertions about how marginal costs in  
15 Manitoba Hydro's system are calculated and what factors are considered in the calculation  
16 of those costs.

### 17 **5.1 Generation Plant Investment Costs are Considered**

18  
19 In reference to the direct testimony of Mr. Chernick at page 11 lines 20-24 regarding the  
20 basis of the marginal cost/value of generation, Manitoba Hydro clarifies that, it does use  
21 separate values for capacity and energy, as stated in the response to CAC-GAC/MH I-4(b).  
22 Hence the marginal generation cost estimates consider the value on the export market of  
23 both energy and generation capacity. The generation capacity component represents the  
24 cost of carrying the generation plant investment.

### 25 **5.2 Methodology for Marginal Transmission and Distribution Costs**

26  
27 This section addresses the written evidence of Mr. Chernick at pages 13-14 with respect to  
28 the analysis of marginal transmission and distribution costs.

29 Manitoba Hydro has been reviewing aspects of the methodology used to determine  
30 transmission and distribution marginal costs, which represent approximately 20% of the  
31 total generation, transmission and distribution marginal costs. This review is expected to  
32 address the concerns raised regarding treatment of load growth and overhead transformers.

33 With respect to the O&M associated with load-related projects, Manitoba Hydro  
34 recognizes the transmission and distribution marginal costs do not include potential

1 operation and maintenance costs on the deferred cost, but notes that in most cases the  
2 O&M costs for the project would be negligible, contributing around 2% to the overall  
3 marginal cost number.

4 The Roblin South Station 230-KV Reactor was not included in the marginal cost  
5 calculation as it was installed for voltage control on the interprovincial interconnection  
6 transmission line between Manitoba and Saskatchewan. As this particular installation was  
7 driven by the need for voltage control and not the prevention of thermal overloading, the  
8 costs of this reactor were determined to be unrelated to increases in demand.

## 9 **6.0 NEED FOR WUSKWATIM**

10

11 This section addresses the question of the need for Wuskwatim raised by Mr. Bowman in  
12 response to PUB/MIPUG I-7.

13 Undertaking #22 of the 2010 GRA provides the following context:

14 “during the “need for and alternatives to” process in 2003 it was stated that,  
15 although the advancement of the Wuskwatim G.S. was being justified primarily on  
16 the basis of obtaining profits from new export revenues, there were many other  
17 factors that provided justification for early construction. At that time it was stated  
18 that one such additional justification was that it provided a source of generation  
19 should the Manitoba domestic load grow at a rate higher than forecast. In fact,  
20 subsequent to 2003 there was a significant increase in the load growth such that  
21 with the 2007/08 load forecast Wuskwatim G.S. would be required by 2012/13 to  
22 serve existing load requirements. It was only in the last three years that the load  
23 growth has decreased to the point where Wuskwatim G.S. is not required until  
24 2019/20 from the perspective of the dependable energy criterion.”

25 The 2003 review of the Wuskwatim Generation and Transmission Projects, included a  
26 comparison to wind generation. The conclusion of the Commission which conducted this  
27 review was “*that the Projects represent a viable alternative and an in-service date of 2010*  
28 *should be pursued*”. Subsequently, Manitoba Hydro, through power purchase agreements,  
29 added wind generation to its supply portfolio. Undertaking #22 does not address the  
30 addition of wind generation.

31 To respond appropriately to the question of whether Wuskwatim was in fact required as a  
32 new resource to serve Manitoba the removal of Wuskwatim, as well as wind from the  
33 supply/demand table is required prior to conducting such analysis. Removing these

1 generation resources results in a persistent shortfall starting in 2011/12 as shown in the  
2 table provided in Manitoba Hydro's response to MIPUG/MH II-16(b). These shortfalls  
3 would be filled by the Wuskwatim G.S.

## 4 **7.0 RATE OPTIONS**

5  
6 The purpose of this section is to address Mr. Bowman's evidence with respect to the  
7 Curtailable Rate Program (CRP).

### 8 9 **7.1 Curtailable Rate Program**

10  
11 Mr. Bowman recommends that the PUB reject Manitoba Hydro's proposed reductions to  
12 caps on CRP Option 'A' or 'R' load.

13  
14 Manitoba Hydro asserts that there is ample evidence that the CRP industrial customers  
15 have benefited from the program and existing participants will continue to do so within the  
16 proposed caps. Manitoba Hydro explained in PUB/MH II-99(b) why the proposed  
17 reductions to Option 'A' and 'R' caps are justified. The following sections expand on  
18 Manitoba Hydro's justification for reducing these caps. The following sections also  
19 respond to statements provided in Mr. Bowman's written evidence and IR responses.

#### 20 21 **7.1.1 Low Capacity Prices in Neighbouring Markets due to Capacity Surpluses**

22  
23 Current export market capacity prices continue to be soft due to installed capacity  
24 surpluses. MISO's recent Voluntary Capacity Auction (VCA) prices, expressed in  
25 \$USD/kW/month are provided in table (Figure 11) below. These prices are only a very  
26 small fraction of the discount afforded to Option 'A' and Option 'R' load. For 2010/11  
27 period, the VCA cleared at an average price below \$0.001/kW month. This is less than  
28 0.1% of the marginal value of capacity used to establish CRP rates. Under these  
29 conditions, conversion of additional Firm Service industrial load to the CRP rates would  
30 result in a net loss to Manitoba Hydro.

31

1

Figure 11

<b>MISO Voluntary Capacity Auction clearing prices for 2009/10 and 2010/11 expressed in \$US/kW/month.</b>		
	<b>2009/10</b>	<b>2010/11</b>
April	\$0.00035	\$0.00025
May	\$0.00035	\$0.00025
June	\$0.00500	\$0.00035
July	\$0.01000	\$0.00050
August	\$0.01000	\$0.00028
September	\$0.00300	\$0.00025
October	\$0.00025	\$0.00001
November	\$0.00025	\$0.00002
December	\$0.00100	\$0.00010
January	\$0.00250	\$0.00020
February	\$0.00094	\$0.00019
March	\$0.00050	\$0.00010
<b>Average (\$US/kW/month)</b>	<b>\$0.00285</b>	<b>\$0.00021</b>

2

3 **7.1.2 No Long-term Commitment to Provide Curtailment Service**

4 Manitoba Hydro does not rely on curtailable load in its long-term resource adequacy plans  
 5 because CRP customers are not obligated to make long-term commitments. Despite this  
 6 fact, participants in the CRP program benefit from rates that are discounted based on  
 7 Manitoba Hydro's *long-term* value of capacity. The CRP applies a stable discount to  
 8 Option 'A' and Option 'R' customers equivalent to 70% of the Reference Discount, which  
 9 represents Manitoba Hydro's long-term marginal value of capacity<sup>5</sup>. The Reference  
 10 Discount for 2012/13 is \$3.21/kW/month which is orders of magnitude above the current  
 11 capacity market prices provided in Figure 11.

12

13 Manitoba Hydro asserts that the practice of applying a discount based on its long-term  
 14 value of capacity is already consistent with Mr. Bowman's statement, "it is appropriate to  
 15 consider future price forecast in the assessment of the CRP value."<sup>6</sup> Manitoba Hydro is not  
 16 proposing to reduce the discount to CRP customers, rather it recognizes the long-term

---

<sup>5</sup> The value of CRP capacity is based on 42% of the annualized carrying cost of a simple cycle combustion turbine.

<sup>6</sup> Pre-filed Testimony of P. Bowman for the 2012/13 and 2013/14 GRA submitted on behalf of MIPUG, November 16, 2012, p.5-5.

1 value CRP load provides and the investments existing CRP customers may have made to  
2 be capable of providing this service, and plans to continue the program at the current  
3 subscription levels. Manitoba Hydro asserts that, contrary to the cautionary statements  
4 expressed by Mr. Bowman<sup>7</sup>, continuance of the discount offered to CRP load and  
5 maintenance of caps consistent with current subscription levels indicates that Manitoba  
6 Hydro does in fact “place value on the long-term or relationships aspects of the program.”  
7 Manitoba Hydro notes that no new customers have signed on to the program for a number  
8 of years.

9  
10 **7.1.3 Manitoba Hydro has decided that additional CRP load is not required to**  
11 **respond to a MISO Maximum Generation Event<sup>8</sup>**

12  
13 As recent as 2011<sup>9</sup>, Manitoba Hydro indicated that it was in the process of reviewing the  
14 CRP option caps as changes were occurring within the MISO jurisdiction. If a Maximum  
15 Generation Event were to occur in the MISO region, MISO may call upon the capacity  
16 associated with Manitoba Hydro’s capacity backed export sales. In 2011, Manitoba Hydro  
17 was considering increasing the Option ‘A’ curtailable load cap to 400 MW to backstop  
18 Manitoba Hydro’s Brandon combustion turbines and its gas-fired steam turbines at Selkirk  
19 G.S. Manitoba Hydro could use the Option ‘A’ curtailable load to bridge the period  
20 required to start its gas-fired generation.

21  
22 However, the likelihood of MISO experiencing a Maximum Generation Event is highest in  
23 the summer when it experiences its peak load. During this period the Manitoba load is over  
24 one-thousand mega-Watts less than its winter peak load and thermal generation is not  
25 required to support capacity backed export sales even during a Maximum Generation  
26 Event. As a result a decision was made not to increase the CRP Option ‘A’ cap at this  
27 time. Manitoba Hydro made this assessment after the 2011 CRP report was issued.

28  
29 The current subscription levels of Option ‘A’ and Option ‘R’ Curtailable Load are  
30 consistent with Manitoba Hydro’s needs in the near term and our long term commitment to  
31 existing customers. Moving forward, Manitoba Hydro expects to participate in the MISO  
32 Annual Capacity Auction. Manitoba Hydro will assess the applicability and economic  
33 benefit of using curtailable load to support term capacity sale obligations in this auction or

---

<sup>7</sup> PUB/MIPUG-I-22(a) and (b), p.2 line 13-23.

<sup>8</sup> An event triggered by an emergency in the MISO jurisdiction.

<sup>9</sup> Manitoba Hydro, Report to the Public Utilities Board on the Curtailable Rate Program, October, 2011, p. 8.

1 through bilateral contracts. If there is merit to using curtailable load in this manner,  
2 Manitoba Hydro may increase limits to Option ‘A’ CRP load in the future.

3  
4 **8.0 OTHER**

5  
6 This section addresses the written evidence of Mr. Chernick on behalf of GAC with respect  
7 to comments regarding the reviewability of Manitoba Hydro’s proposals and analysis.

8  
9 **8.2 Reviewability of Manitoba Hydro’s Application**

10  
11 At page 4 of his evidence, Mr. Chernick states that Manitoba Hydro “filed its 2012/2013  
12 rate design proposals, including a time-of-use rate for large general service customers, on  
13 October 3, 2012.” Manitoba Hydro notes that it filed rate schedules for rates to be effective  
14 in the 2012/13 fiscal year on July 6, 2012, in its filing of Volume II Application materials.  
15 Manitoba Hydro filed rate schedules for the 2013/14 fiscal year on October 3, 2012,  
16 including a proposal to implement TOU rates and customer-class differentiated rate  
17 increases, following approval by the Manitoba Hydro-Electric Board. By letter dated  
18 November 6, 2012, the PUB confirmed that Manitoba Hydro’s request for TOU Rates and  
19 class-differentiated rate increases would be reviewed separately from the GRA, as part of  
20 the Cost of Service Study Review process expected to take place in the spring of 2013. As  
21 such, Manitoba Hydro filed revised rate schedules on November 7, 2012 on an across-the-  
22 board basis, consistent with Manitoba Hydro’s past rate design practices, a practice that is  
23 familiar to all parties to this proceeding. All parties will have the opportunity to examine  
24 Manitoba Hydro’s TOU rate proposal in the process expected to take place in the spring of  
25 2013.

26  
27 Also on page 4 of his evidence, Mr. Chernick states that “The fuel-switching report was  
28 filed..., two months after the initial GRA filing and three years late.” The fuel switching  
29 report was filed with the PUB in response to directive 17 from Orders 116/08 & 150/08,  
30 but does not form part of Manitoba Hydro’s General Rate Application. While this report  
31 contains future policy implications, it does not have a direct impact on the revenue  
32 requirement for the two Test Years in this Application.

33  
34 At page 31 of his evidence, Mr. Chernick recommends that “the Board should request  
35 comments from Hydro and intervenors on the additional documents that should be in the  
36 GRA filing requirements”, and recommends that “the Board should require that Hydro file

1 its proof-of-revenue tables, bill comparisons, COS studies and marginal cost studies as  
2 Excel spreadsheets with all formulas intact.”

3  
4 The Public Utilities Board has been able to fulfill its mandate to set just and reasonable  
5 rates for Manitoba Hydro for many years with the existing minimum filing requirements  
6 and without access to materials in Excel format. In this proceeding, Manitoba Hydro has  
7 agreed to provide, upon request, data only spreadsheets to intervenors wishing to undertake  
8 their own analysis. However, the recommendation with respect to filing its proof-of-  
9 revenue model, bill comparisons, COS studies and marginal cost studies in Excel format  
10 ignores Manitoba Hydro’s concerns related to the potentially significant amount of time  
11 and effort that would be required to prepare the models to be placed in the public domain,  
12 to educate other parties in the use of these models, and to verify alternative scenarios  
13 developed by third parties using the models. This recommendation also ignores that some  
14 of these models contain commercially sensitive information and the potential infringement  
15 on the third-party rights over the models. As such, Manitoba Hydro does not agree with the  
16 need for additional filing requirements as recommended by Mr. Chernick.

17  
18 **8.3 Consultation on Cost of Service and Time-of-Use Rate Proposal**

19  
20 In conjunction with this General Rate Application, Manitoba Hydro has already filed  
21 evidence with regards to its preferred treatment of its Cost of Service Study and has  
22 applied for the differentiated treatment of the rate increases to various customer classes.  
23 As part of its rate proposals already filed, Manitoba Hydro sought approval to implement  
24 Time-of-Use rates for General Service Large customers, served at levels greater than 30  
25 kV.

26  
27 As set out in Order 98/12, the Public Utilities Board determined that Cost of Service  
28 matters were to be addressed in a separate public hearing process to be scheduled for 2013.  
29 Further, by way of its letter dated November 6, 2012, the Public Utilities Board determined  
30 that Manitoba Hydro’s request for the implementation of both Time-of-Use rates and the  
31 application of class differentiated rate adjustments should be considered in the same public  
32 hearing process set out for the review of the Cost of Service Study.

33  
34 Mr. Chernick, in response to MH/GAC (Chernick) – 1, attached correspondence between  
35 Mr. Peter Miller and Manitoba Hydro, dated November 25, 2012, in which Mr. Miller  
36 proposed four topics for consideration in the public hearing process (and associated  
37 consultation sessions with interested parties) to review the Cost of Service, Differentiated

1 Rates and Time-of-Use General Service >30 kV rates. As set out in this correspondence,  
2 the topics, in order of GAC's preference, are:

- 3 1. Residential rate structure
- 4 2. Non-TOU General Service rate structures
- 5 3. General Service TOU rate structures, and
- 6 4. Cost of Service issues.

7  
8 Manitoba Hydro reiterates that it has made application for the implementation of Time-of-  
9 Use Rates for General Service >30kV and for the implementation of rate increases on a  
10 class-differentiated basis, and that these matters, in conjunction with a review of the  
11 supporting Cost of Service Study, are the only matters that should be addressed in the  
12 proposed public hearing process and any consultation sessions preceding it. Significant  
13 consultation has already been undertaken on the Time-of-Use Rates proposal with both  
14 directly affected customers and other interested parties, and a timely and expedient public  
15 review should be pursued at the earliest opportunity. Manitoba Hydro would consider the  
16 merits of hosting a technical conference regarding its proposed Cost of Service Study prior  
17 to any scheduled public hearing, which would provide an opportunity for all parties to gain  
18 better understanding of the Cost of Service matters that are to be addressed. This technical  
19 conference would not, however, be intended to solicit alternatives to its already-filed  
20 proposal.

21  
22 With respect to other rate design matters, as stated in the response to PUB/MH I-149,  
23 Manitoba Hydro has not advanced a plan to implement inverted rates for any customer  
24 classes in this Application. Manitoba Hydro has no formal timetable as to the development  
25 of an inverted rate structure for any customer classes. Furthermore, in its response to  
26 PUB/MH II-101(a), Manitoba Hydro advises that inverted rates for Residential class  
27 customers are not under active consideration at this time.

28  
29 Given that Manitoba Hydro has advanced evidence on the Cost of Service Study, which  
30 would support the proposal for the differentiation of rate changes to various customer  
31 classes, and the design of Time-of-Use Rates for General Service customers >30kV,  
32 Manitoba Hydro is of the view that the upcoming public review process and associated  
33 stakeholder conferences should be confined to those matters. Manitoba Hydro does not  
34 support GAC's proposal to review residential rate structures at this time, nor does it  
35 propose to expand its current proposal to include "Non-TOU General Service rate  
36 structures" in the upcoming public hearing process. Manitoba Hydro is prepared to



- 1 consider stakeholder conferences on these matters once the current GRA, including the
- 2 Cost of Service and TOU rate review is concluded.

**ATTACHMENT A: COMPARISON OF ASL AND ELG SCENARIOS FOR A  
 DECLINING ASSET POOL**

**Asset Cost and Retirement Assumptions**

A \$100,000 investment is made in a group of like assets with an average life of 5.5 years and a simple step-function survivor curve (i.e., \$10,000 of gross plant retired each year). Retirements occur at the end of each year.

**Annual Expense: ELG procedure for group depreciation**

Year	Cost			Accumulated Depreciation			Annual Expense			
	Cost at Beginning of Year	Assets Retired	Cost at End of Year	Depreciation Taken	Depreciation Retired	Accumulated Depreciation at End of Year	Depreciation Rate	Depreciation Expense	(Gain) / Loss on Assets Retired	Total Expense
1	\$ 100,000	\$ (10,000)	\$ 90,000	\$ (29,290)	\$ 10,000	\$ (19,290)	29.3%	\$ 29,290	\$ -	\$ 29,290
2	90,000	(10,000)	80,000	(19,290)	10,000	(28,579)	21.4%	19,290	-	19,290
3	80,000	(10,000)	70,000	(14,290)	10,000	(32,869)	17.9%	14,290	-	14,290
4	70,000	(10,000)	60,000	(10,956)	10,000	(33,825)	15.7%	10,956	-	10,956
5	60,000	(10,000)	50,000	(8,456)	10,000	(32,282)	14.1%	8,456	-	8,456
6	50,000	(10,000)	40,000	(6,456)	10,000	(28,738)	12.9%	6,456	-	6,456
7	40,000	(10,000)	30,000	(4,790)	10,000	(23,528)	12.0%	4,790	-	4,790
8	30,000	(10,000)	20,000	(3,361)	10,000	(16,889)	11.2%	3,361	-	3,361
9	20,000	(10,000)	10,000	(2,111)	10,000	(9,000)	10.6%	2,111	-	2,111
10	10,000	(10,000)	-	(1,000)	10,000	-	10.0%	1,000	-	1,000
		\$ (100,000)		\$ (100,000)	\$ 100,000			\$ 100,000	\$ -	\$ 100,000

**Depreciation Rate:**

**Year 1:** [(\$10,000 / 10 years) + (\$10,000 / 9 years) + ... + (\$10,000 / 1 year)] / \$100,000

**Year 2:** [(\$10,000 / 10 years) + (\$10,000 / 9 years) + ... + (\$10,000 / 2 year)] / \$90,000

...

**Year 10:** (\$10,000 / 10 years) / \$10,000

**Asset Retirement Calculations:** Gains and losses on disposition of assets are recognized immediately. The amount of accumulated depreciation retired is calculated as: Cost of item(s) retired x number of years depreciated / expected life of item(s) retired.

**Year 1:** \$10,000 x 1 year / 1 year

**Year 2:** \$10,000 x 2 years / 2 years

...

1 **Annual Expense: ASL procedure for group depreciation with recognition of gains**  
 2 **and losses**

Year	Cost			Accumulated Depreciation			Annual Expense			
	Cost at Beginning of Year	Assets Retired	Cost at End of Year	Depreciation Taken	Depreciation Retired	Accumulated Depreciation at End of Year	Depreciation Rate	Depreciation Expense	(Gain) / Loss on Assets Retired	Total Expense
1	\$ 100,000	\$ (10,000)	\$ 90,000	\$ (18,182)	\$ 1,818	\$ (16,364)	18.2%	\$ 18,182	\$ 8,182	\$ 26,364
2	90,000	(10,000)	80,000	(16,364)	3,636	(29,091)	18.2%	16,364	6,364	22,727
3	80,000	(10,000)	70,000	(14,545)	5,455	(38,182)	18.2%	14,545	4,545	19,091
4	70,000	(10,000)	60,000	(12,727)	7,273	(43,636)	18.2%	12,727	2,727	15,455
5	60,000	(10,000)	50,000	(10,909)	9,091	(45,455)	18.2%	10,909	909	11,818
6	50,000	(10,000)	40,000	(9,091)	10,909	(43,636)	18.2%	9,091	(909)	8,182
7	40,000	(10,000)	30,000	(7,273)	12,727	(38,182)	18.2%	7,273	(2,727)	4,545
8	30,000	(10,000)	20,000	(5,455)	14,545	(29,091)	18.2%	5,455	(4,545)	909
9	20,000	(10,000)	10,000	(3,636)	16,364	(16,364)	18.2%	3,636	(6,364)	(2,727)
10	10,000	(10,000)	-	(1,818)	18,182	-	18.2%	1,818	(8,182)	(6,364)
		\$ (100,000)		\$ (100,000)	\$ 100,000			\$ 100,000	\$ -	\$ 100,000

3  
4

5 **Depreciation Rate:**  $(1 / \text{Average Service Life}) = 1 / 5.5 \text{ years} = 18.181 \%$

6

7 **Asset Retirement Calculations:** Gains and losses on disposition of assets are recognized  
 8 immediately. The amount of accumulated depreciation retired is calculated as: Cost of  
 9 item(s) retired x depreciation rate x number of years depreciated.

- 10 **Year 1:** \$10,000 x 18.181% x 1 year  
 11 **Year 2:** \$10,000 x 18.181% x 2 years  
 12 ...

13

14 **Annual Expense: ASL Procedure for group depreciation with deferral of gains and**  
 15 **losses, and with depreciation studies every three years**

Year	Cost			Accumulated Depreciation			Annual Expense				
	Cost at Beginning of Year	Assets Retired	Cost at End of Year	Depreciation Taken	Depreciation Retired	Accumulated Depreciation at End of Year	Depreciation Rate		Depreciation Expense	(Gain) / Loss on Assets Retired	Total Expense
							Base	True-up			
1	\$ 100,000	\$ (10,000)	\$ 90,000	\$ (18,182)	\$ 10,000	\$ (8,182)	18.2%	0.0%	\$ 18,182	\$ -	\$ 18,182
2	90,000	(10,000)	80,000	(16,364)	10,000	(14,545)	18.2%	0.0%	16,364	-	16,364
3	80,000	(10,000)	70,000	(14,545)	10,000	(19,091)	18.2%	0.0%	14,545	-	14,545
4	70,000	(10,000)	60,000	(20,364)	10,000	(29,455)	18.2%	10.9%	20,364	-	20,364
5	60,000	(10,000)	50,000	(17,455)	10,000	(36,909)	18.2%	10.9%	17,455	-	17,455
6	50,000	(10,000)	40,000	(14,545)	10,000	(41,455)	18.2%	10.9%	14,545	-	14,545
7	40,000	(10,000)	30,000	(9,455)	10,000	(40,909)	18.2%	5.5%	9,455	-	9,455
8	30,000	(10,000)	20,000	(7,091)	10,000	(38,000)	18.2%	5.5%	7,091	-	7,091
9	20,000	(10,000)	10,000	(4,727)	10,000	(32,727)	18.2%	5.5%	4,727	-	4,727
10	10,000	(10,000)	-	14,545	18,182	-	18.2%	-163.6%	(14,545)	(8,182)	(22,727)
		\$ (100,000)		\$ (108,182)	\$ 108,182				\$ 108,182	\$ (8,182)	\$ 100,000

16  
17

18 **Base Depreciation Rate:**  $(1 / \text{Average Service Life}) = 1 / 5.5 \text{ years} = 18.181 \%$

19

1 **True-Up Depreciation Rate:**

2 **Year 4 – 6 True-up** (Based on balances at end of Year 3):

3 Expected accumulated Depreciation = Surviving assets x age / average service life  
4 = \$70,000 x 3 / 5.5 = \$ 38,182

5 Accumulated depreciation variance = \$38,182 - \$19,091 = \$19,091 shortfall

6 Average Expected Remaining Life = Average service life – age = 5.5 – 3 = 2.5  
7 years

8 Required annual adjustment to depreciation expense = variance / average remaining  
9 life = \$19,091 / 2.5 years = \$7,636

10 True-up Depreciation Rate = annual adjustment / total depreciable cost = \$7,636 /  
11 \$70,000 = **10.9%**

12 **Year 7 – 9 True-up** (Based on balances at end of Year 6):

13 Expected accumulated Depreciation = Surviving assets x age / average service life  
14 = \$40,000 x 6 / 5.5 = \$ 43,636

15 Accumulated depreciation variance = \$43,636 - \$41,455 = \$2,182 shortfall

16 Average Expected Remaining Life = is assumed to be 1 year as the actual age of  
17 the asset exceeds the average life

18 Required annual adjustment to depreciation expense = variance / average remaining  
19 life = \$2,182 / 1 year = \$2,182

20 True-up Depreciation Rate = annual adjustment / total depreciable cost = \$(2,182) /  
21 \$40,000 = **5.5%**

22 **Year 10 True-up** (Based on balances at end of Year 9):

23 Expected accumulated Depreciation = Surviving assets x age / average service life  
24 = \$10,000 x 9 / 5.5 = \$ 16,364

25 Accumulated depreciation variance = \$16,364 - \$32,727 = \$(16,364), an over-  
26 accrual

27 Average Expected Remaining Life = is assumed to be 1 year as the actual age of  
28 the asset exceeds the average life

29 Required annual adjustment to depreciation expense = variance / average remaining  
30 life = \$(16,364) / 1 years = \$16,364

31 True-up Depreciation Rate = annual adjustment / total depreciable cost = \$(16,364)  
32 / \$10,000 = **-163.6%**

1 **Asset Retirement Calculations:** As all gains and losses on disposition of assets are  
2 deferred until the last items are retired, an amount equal to cost is removed from  
3 accumulated depreciation with each interim retirement. All remaining accumulated  
4 depreciation is retired in year 10, generating a gain on the final disposition for the asset  
5 group.  
6

1           **ATTACHMENT B: COMPARISON OF ASL AND ELG SCENARIOS FOR AN**  
2           **ASSET POOL WITH A CONSTANT LEVEL OF INVESTMENT**

3  
4       In this attachment, four scenarios are provided to illustrate showing the different impact in  
5       the flow of expenses to the income statement that would result from the use of the Average  
6       Service Life (ASL) procedure for group depreciation with differing implementation  
7       patterns, versus the Equal Life Group (ELG) procedure for group depreciation.

8  
9       **Asset Cost and Retirement Assumptions**

10  
11       An identical asset pool is considered in each of the following four scenarios. For  
12       Simplicity, the effects of inflation are ignored. The asset pool consists of:

- 13       • Five units each costing \$100, which have a service life of five years, and which will  
14       be replaced immediately on retirement with five more units.
- 15       • Five units each costing \$100, which have an expected service life of fifteen years,  
16       and which will be replaced immediately on retirement.
- 17       • All asset retirements and additions occur at the end of the year expected.
- 18       • At any point in time:
- 19           - The assets have a combined cost of \$1,000;
- 20           - One half of the asset base is expected to last five years and one half of the  
21           asset base is expected to last fifteen years; and,
- 22           - The weighted average expected service life of the combined asset group is  
23           ten years.

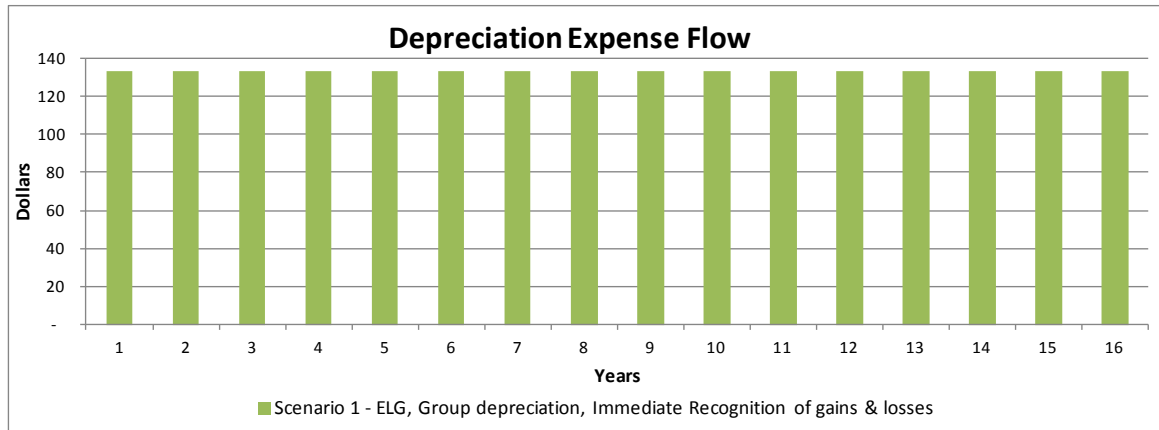
**Asset Cost Continuity Schedule**

Year	Asset Sub-Group 1 (5 year life)				Asset Sub-Group 2 (15 year life)				Combined Asset Group			
	Cost at Beginning of Year	Assets Retired	Assets Added	Cost at End of Year	Cost at Beginning of Year	Assets Retired	Assets Added	Cost at End of Year	Cost at Beginning of Year	Assets Retired	Assets Added	Cost at End of Year
0	\$ -		\$ 500	\$ 500	\$ -		\$ 500	\$ 500	\$ -		\$ 1,000	\$ 1,000
1	500			500	500			500	1,000			1,000
2	500			500	500			500	1,000			1,000
3	500			500	500			500	1,000			1,000
4	500			500	500			500	1,000			1,000
5	500	(500)	500	500	500			500	1,000	(500)	500	1,000
6	500			500	500			500	1,000			1,000
7	500			500	500			500	1,000			1,000
8	500			500	500			500	1,000			1,000
9	500			500	500			500	1,000			1,000
10	500	(500)	500	500	500			500	1,000	(500)	500	1,000
11	500			500	500			500	1,000			1,000
12	500			500	500			500	1,000			1,000
13	500			500	500			500	1,000			1,000
14	500			500	500			500	1,000			1,000
15	500	(500)	500	500	500	(500)	500	500	1,000	(1,000)	1,000	1,000
16	500			500	500			500	1,000			1,000
		\$(1,500)	\$2,000			\$(500)	\$1,000			\$(2,000)	\$3,000	

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**Scenario 1: ELG; Group depreciation; Immediate recognition of gains and losses.**

This scenario is comparable to the ELG implementation which has been proposed for use by Manitoba Hydro for IFRS and regulatory reporting purposes.



6

**Scenario 1 - Annual Expense & Accumulated Depreciation Continuity Schedule**

Year	Cost	Depreciation				Expenses Recognized			Accumulated Depreciation	
		Base Rate	Base Expense	True-Up Rate	True-Up Expense	Total Depreciation	(Gain) / Loss on Asset	Total Annual	Depreciation Retired	at End of Year
1	\$ 1,000	13.3%	\$ 133		\$ -	\$ 133	\$ -	\$ 133	\$ -	\$ (133)
2	1,000	13.3%	133		-	133	-	133	-	(267)
3	1,000	13.3%	133		-	133	-	133	-	(400)
4	1,000	13.3%	133		-	133	-	133	-	(533)
5	1,000	13.3%	133		-	133	-	133	500	(167)
6	1,000	13.3%	133	0.0%	-	133	-	133	-	(300)
7	1,000	13.3%	133	0.0%	-	133	-	133	-	(433)
8	1,000	13.3%	133	0.0%	-	133	-	133	-	(567)
9	1,000	13.3%	133	0.0%	-	133	-	133	-	(700)
10	1,000	13.3%	133	0.0%	-	133	-	133	500	(333)
11	1,000	13.3%	133	0.0%	-	133	-	133	-	(467)
12	1,000	13.3%	133	0.0%	-	133	-	133	-	(600)
13	1,000	13.3%	133	0.0%	-	133	-	133	-	(733)
14	1,000	13.3%	133	0.0%	-	133	-	133	-	(867)
15	1,000	13.3%	133	0.0%	-	133	-	133	1,000	-
16	1,000	13.3%	133	0.0%	-	133	-	133	-	(133)
			\$ 2,133		\$ -	\$ 2,133	\$ -	\$ 2,133	\$ 2,000	

**Scenario 1 Calculations:**

**Base Depreciation Rate:**  $[(\$500 / 5 \text{ years}) + (\$500 / 15 \text{ years})] / \$1000$

**Asset Retirement Calculations:** Gains and losses on disposition of assets are recognized immediately in this scenario. Accumulated depreciation retired is calculated as Cost of item(s) retired x number of years depreciated / expected life of items retired

- Year 5:  $\$500 \times 5 \text{ years} / 5 \text{ years} = \$500$  accumulated depreciation, \$0 loss.
- Year 10:  $\$500 \times 5 \text{ years} / 5 \text{ years} = \$500$  accumulated depreciation, \$0 loss.
- Year 15: [Sub-Group 1:  $\$500 \times 5 \text{ years} / 5 \text{ years} = \$500$  accumulated depreciation, \$0 loss] plus [Sub-Group 2:  $\$500 \times 15 \text{ years} / 15 \text{ years} = \$500$  accumulated depreciation, \$0 loss]

**Depreciation Adjustment – True-up Rates:** There is no need for a true-up rate in this scenario to correct depreciation expense, as the accumulated depreciation balance at the end of each 5 year interval matches the expected accumulated balance for the underlying assets:

- Year 5: Sub Group 1:  $\$500 \times (0 / 5) \text{ years} + \text{Sub-Group 2 } \$500 \times (5 / 15) \text{ years} = \$167$
- Year 10: Sub Group 1:  $\$500 \times (0 / 5) \text{ years} + \text{Sub-Group 2 } \$500 \times (10 / 15) \text{ years} = \$333$
- Year 15: Sub Group 1:  $\$500 \times (0 / 5) \text{ years} + \text{Sub-Group 2 } \$500 \times (0 / 15) \text{ years} = \$0$



1 **Suitability for Use in Rate Setting:** This scenario is acceptable for rate setting as the  
2 equal expense pattern matches the assets available for use in each year.

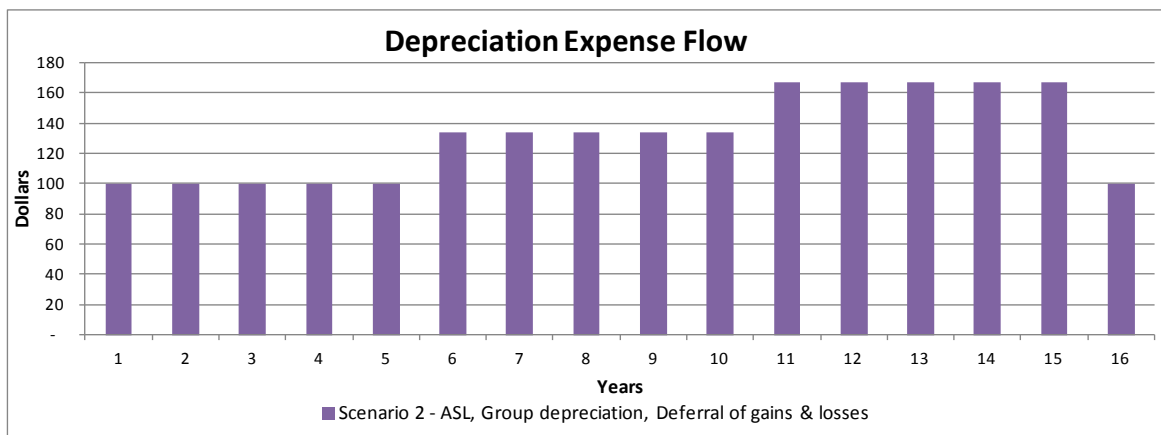
3

4 **IFRS Compliance:** Scenario 1 is IFRS compliant as the pattern of depreciation expense  
5 matches the expected life for all assets, and gains and/or losses are realized immediately in  
6 income.

7

8 **Scenario 2: ASL; Group depreciation; Deferral of gains and losses**

9 This scenario is comparable to the ASL implementation which is currently used by  
10 Manitoba Hydro for Canadian GAAP and regulatory reporting purposes.



11

12

13 Gains or losses on disposition of assets are deferred, and are recovered over the remaining  
14 life of the assets in the group through the use of a “true-up” depreciation adjustment which  
15 is determined at each depreciation study.

16

17 The scenario assumes a five year interval between depreciation studies, which is consistent  
18 with the approach taken by Manitoba Hydro.

**Scenario 2 - Annual Expense & Accumulated Depreciation Continuity Schedule**

Year	Cost	Depreciation				Expenses Recognized			Depreciation Retired	Accumulated Depreciation at End of Year
		Base Rate	Base Expense	True-Up Rate	True-Up Expense	Total Depreciation Expense	(Gain) / Loss on Asset Disposal	Total Annual Expense		
1	\$ 1,000	10.0%	\$ 100		\$ -	\$ 100	\$ -	\$ 100	\$ -	\$ (100)
2	1,000	10.0%	100		-	100	-	100	-	(200)
3	1,000	10.0%	100		-	100	-	100	-	(300)
4	1,000	10.0%	100		-	100	-	100	-	(400)
5	1,000	10.0%	100		-	100	-	100	500	-
6	1,000	10.0%	100	3.3% <b>A</b>	33	133	-	133	-	(133)
7	1,000	10.0%	100	3.3%	33	133	-	133	-	(267)
8	1,000	10.0%	100	3.3%	33	133	-	133	-	(400)
9	1,000	10.0%	100	3.3%	33	133	-	133	-	(533)
10	1,000	10.0%	100	3.3%	33	133	-	133	500	(167)
11	1,000	10.0%	100	6.7% <b>B</b>	67	167	-	167	-	(333)
12	1,000	10.0%	100	6.7%	67	167	-	167	-	(500)
13	1,000	10.0%	100	6.7%	67	167	-	167	-	(667)
14	1,000	10.0%	100	6.7%	67	167	-	167	-	(833)
15	1,000	10.0%	100	6.7%	67	167	-	167	1,000	-
16	1,000	10.0%	100	0.0% <b>C</b>	-	100	-	100	-	(100)
			\$ 1,600		\$ 500	\$ 2,100	\$ -	\$ 2,100	\$ 2,000	

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**Scenario 2 Calculations:**

**Base Depreciation Rate:**  $(1 / \text{Average Service Life}) = (1 / 10) = 10\%$

**Asset Retirement Calculations:** As the gains or losses on disposition of assets are deferred in this scenario, the accounting entry posted is to reduce both cost and accumulated depreciation by the full original cost of the assets to be retired, in this scenario, \$500 at the end of years 5 and 10, and \$1,000 at the end of year 15.

**1 Depreciation Adjustment – True-up Rates:**

**A) Scenario 2 - True-Up Rate Calculation - End of Year 5:**

Age	Cost	Average Expected Life (Years)	Age as a % of Expected Life	Expected Remaining Life (Years)	Expected Accumulated Depreciation
0	\$ 500	10	0.000	10	\$ 0
5	500	10	0.500	5	(250)
10	-	10	1.000	0	-
	<u>\$ 1,000</u> a				<u>(\$ 250)</u> b
Actual Accumulated Depreciation					<u>-</u> c
Accumulated Depreciation Variance					(b - c) (\$ 250) d
Weighted Average Remaining Life:					
(sum of % total cost x remaining life for each age)					<u>7.5</u> e
Annual depreciation true-up required:					(d / e) (\$ 33) f
Depreciation True-up Rate:					(f / a) <b>3.3%</b>

2  
3

**B) Scenario 2 - True-Up Rate Calculation - End of Year 10:**

Age	Cost	Expected Life (Years)	Age as a % of Expected Life	Expected Remaining Life (Years)	Expected Accumulated Depreciation
0	\$ 500	10	0.000	10	\$ 0
5	-	10	0.500	5	-
10	500	10	1.000	0	(500)
	<u>\$ 1,000</u> a				<u>(\$ 500)</u> b
Actual Accumulated Depreciation					<u>(167)</u> c
Accumulated Depreciation Variance					(b - c) (\$ 333) d
Weighted Average Remaining Life:					
(sum of % total cost x remaining life for each age)					<u>5</u> e
Annual depreciation true-up required:					(d / e) (\$ 67) f
Depreciation True-up Rate:					(f / a) <b>6.7%</b>

4

**C) Scenario 2 - True-Up Rate Calculation - End of Year 15:**

Age	Cost	Expected Life (Years)	Age as a % of Expected Life	Expected Remaining Life (Years)	Expected Accumulated Depreciation
0	\$ 1,000	10	0.000	10	\$ 0
5	-	10	0.500	5	-
0	-	10	0.000	10	-
	<u>\$ 1,000 a</u>				<u>\$ 0 b</u>
	Actual Accumulated Depreciation				<u>- c</u>
	Accumulated Depreciation Variance			(b - c)	\$ 0 d

1 As there is no Accumulated Depreciation Variance at the end of year 15, the true-up rate = **0%**

2  
 3 **Suitability for Use in Rate Setting:** From a rate setting perspective, this scenario is not  
 4 ideal, as it produces a shifting pattern of depreciation expense, where the costs for an  
 5 unchanging asset base increase over time until the longer lived assets in the group are  
 6 retired.

- 7 - In the example, ratepayers in years 6 – 10 are appropriately charged 1/3 of the total  
 8 costs, while ratepayers in years 1 – 5 would benefit from lower depreciation rates,  
 9 and ratepayers in years 10 – 15 would be burdened by higher depreciation rates.

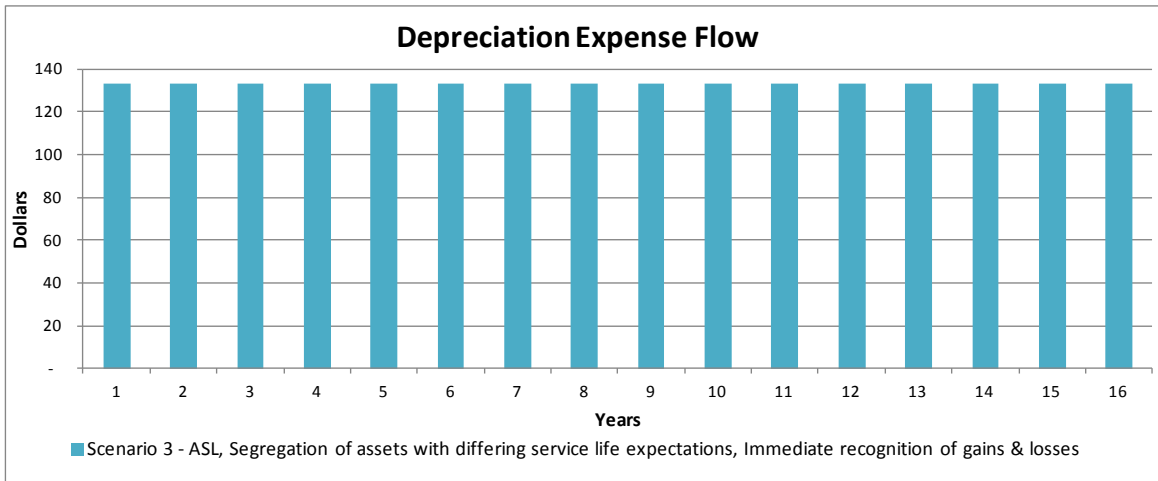
10 **IFRS Compliance:** In Scenario 2, the retirement entry at the end of year 5 fully  
 11 extinguishes the accumulated depreciation balance of the account, leaving no remaining  
 12 balance to be associated with the longer lived items in the group. Scenario 2 fails to meet  
 13 IFRS requirements in two areas:

- 14 - Treatment of gains and losses: IFRS specifically states that gains and losses on the  
 15 disposition of assets are to be recognized as incurred.
- 16 - Pattern of depreciation expense: Following the retirement at the end of year 5, the  
 17 group still contains 5 units which have an individual expected life of 15 years, and  
 18 which has been depreciating for 1/3 of their expected lives, but the accumulated  
 19 depreciation balance does not reflect this. As such, this method does not generate a  
 20 depreciation expense pattern which is true to the useful lives of the parts included  
 21 in the group.

1 **Scenario 3: ASL; Segregation of assets with differing service life expectations;**  
2 **Immediate recognition of gains and losses.**

3 This scenario is comparable to Manitoba Hydro's understanding of the ASL  
4 implementation in use by BC Hydro, Newfoundland and Labrador Hydro, SaskPower and  
5 Hydro Quebec, whereby a significantly greater level of componentization is used in  
6 combination with individual asset depreciation and with immediate recognition of gains &  
7 losses on retirement of assets.

8



9

10

11 In this scenario, the sub-groups of assets with different expected service lives are  
12 separately depreciated, and gains or losses are taken into income in the year the assets are  
13 retired.

**Scenario 3 - Annual Expense & Accumulated Depreciation Continuity Schedule**

Year	Asset Group 1 (5 year life)						
	Cost	Depreciation		(Gain) / Loss on	Annual Expense	Depreciation Retired	Accumulated Depreciation After Retirement
		Rate	Expense	Asset Disposal			
1	\$ 500	20.0%	\$ 100		\$ 100		\$ (100)
2	500	20.0%	100		100		(200)
3	500	20.0%	100		100		(300)
4	500	20.0%	100		100		(400)
5	500	20.0%	100	-	100	500	-
6	500	20.0%	100		100		(100)
7	500	20.0%	100		100		(200)
8	500	20.0%	100		100		(300)
9	500	20.0%	100		100		(400)
10	500	20.0%	100	-	100	500	-
11	500	20.0%	100		100		(100)
12	500	20.0%	100		100		(200)
13	500	20.0%	100		100		(300)
14	500	20.0%	100		100		(400)
15	500	20.0%	100	-	100	500	-
16	500	20.0%	100		100		(100)
			\$ 1,600	-	\$ 1,600	\$ 1,500	

1

**Scenario 3 - Annual Expense & Accumulated Depreciation Continuity Schedule**

Year	Asset Group 2 (15 year life)							Total Annual Expense		
	Cost	Depreciation		(Gain) / Loss on	Annual Expense	Depreciation Retired	Accumulated Depreciation After Retirement	Depreciation Expense	(Gain) / Loss on	Total Expense
		Rate	Expense	Asset Disposal					Asset Disposal	
1	\$ 500	6.7%	\$ 33		\$ 33		\$ (33)	\$ 133	\$ -	\$ 133
2	500	6.7%	33		33		(67)	133	-	133
3	500	6.7%	33		33		(100)	133	-	133
4	500	6.7%	33		33		(133)	133	-	133
5	500	6.7%	33		33		(167)	133	-	133
6	500	6.7%	33		33		(200)	133	-	133
7	500	6.7%	33		33		(233)	133	-	133
8	500	6.7%	33		33		(267)	133	-	133
9	500	6.7%	33		33		(300)	133	-	133
10	500	6.7%	33		33		(333)	133	-	133
11	500	6.7%	33		33		(367)	133	-	133
12	500	6.7%	33		33		(400)	133	-	133
13	500	6.7%	33		33		(433)	133	-	133
14	500	6.7%	33		33		(467)	133	-	133
15	500	6.7%	33	-	33	500	-	133	-	133
16	500	6.7%	33		33		(33)	133	-	133
			\$ 533	-	\$ 533	\$ 500		\$ 2,133	\$ -	\$ 2,133

2

3

1 **Scenario 3 Calculations:**

2

3 **Base Depreciation Rate:**

4 - Asset Group 1:  $(1 / \text{Average Service Life}) = (1 / 5) = 20.0\%$

5 - Asset Group 2:  $(1 / \text{Average Service Life}) = (1 / 15) = 6.7\%$

6 **Depreciation Adjustment – True-up Rates:** There are no need for depreciation true-up  
7 rates in this scenario, as there is no variation in age, in the expected service life, or in the  
8 realization of the service life of the assets within each of the independently depreciated  
9 asset groups.

10

11 **Asset Retirement Calculations:** Gains and losses on disposition of assets are recognized  
12 immediately in this scenario. Accumulated depreciation retired is calculated as Cost of  
13 item(s) retired x depreciation rate in use x number of years depreciated:

14 - Asset Group 1:

15 ○ Year 5:  $\$500 \times 20\% \times 5 \text{ years} = \$500$  accumulated depreciation, \$0 loss.

16 ○ Year 10:  $\$500 \times 20\% \times 5 \text{ years} = \$500$  accumulated depreciation, \$0 loss.

17 ○ Year 15:  $\$500 \times 20\% \times 5 \text{ years} = \$500$  accumulated depreciation, \$0 loss.

18 - Asset Group 2:

19 ○ Year 15:  $\$500 \times 6.7\% \times 15 \text{ years} = \$500$  accumulated depreciation, \$0 loss.

20

21 **Suitability for Use in Rate Setting:** This scenario is acceptable for rate setting as the  
22 equal expense pattern matches the assets available for use in each year.

23

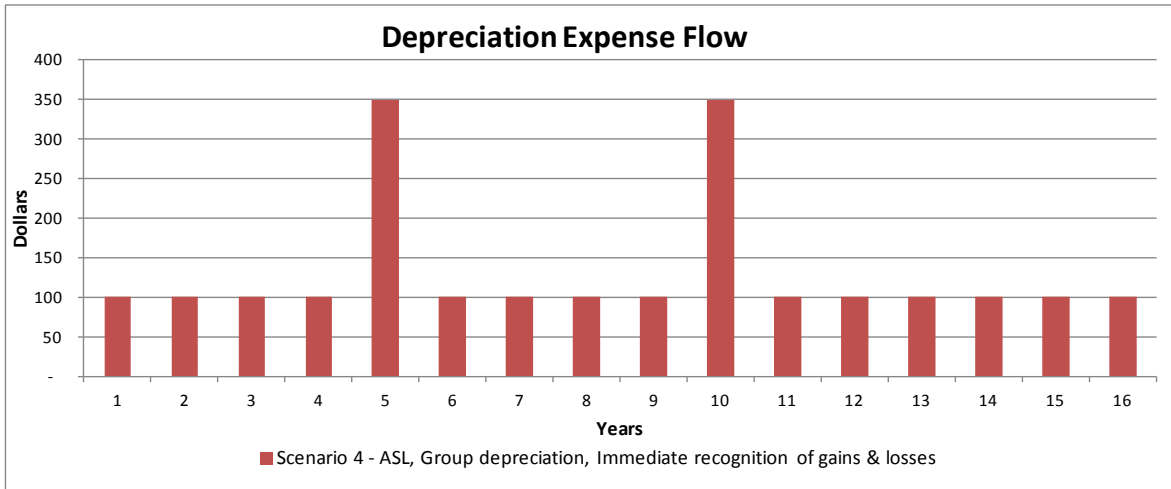
24 **IFRS Compliance:** Scenario 3 is IFRS compliant as the pattern of depreciation expense  
25 matches the expected life for all assets, and gains and/or losses are realized immediately in  
26 income.

27

28 **Scenario 4: ASL; Group Depreciation; Immediate recognition of gains and losses**

29 This scenario reflects the impact on net expense of using ASL with group accounting and  
30 immediate recognition gains and losses on disposal of assets.

31



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Gains or losses on disposition of assets are taken into income in the year the assets are retired.

The scenario assumes a five year interval between depreciation studies, which is consistent with the approach taken by Manitoba Hydro.

**Scenario 4 - Annual Expense & Accumulated Depreciation Continuity Schedule**

Year	Cost	Depreciation				Expenses Recognized			Accumulated Depreciation	
		Base Rate	Base Expense	True-Up Rate	True-Up Expense	Total Depreciation Expense	(Gain) / Loss on Asset Disposal	Total Annual Expense	Depreciation Retired	at End of Year
1	\$ 1,000	10.0%	\$ 100		\$ -	\$ 100	\$ -	\$ 100	\$ -	\$ (100)
2	1,000	10.0%	100		-	100	-	100	-	(200)
3	1,000	10.0%	100		-	100	-	100	-	(300)
4	1,000	10.0%	100		-	100	-	100	-	(400)
5	1,000	10.0%	100		-	100	250	350	250	(250)
6	1,000	10.0%	100	0.0%	-	100	-	100	-	(350)
7	1,000	10.0%	100	0.0%	-	100	-	100	-	(450)
8	1,000	10.0%	100	0.0%	-	100	-	100	-	(550)
9	1,000	10.0%	100	0.0%	-	100	-	100	-	(650)
10	1,000	10.0%	100	0.0%	-	100	250	350	250	(500)
11	1,000	10.0%	100	0.0%	-	100	-	100	-	(600)
12	1,000	10.0%	100	0.0%	-	100	-	100	-	(700)
13	1,000	10.0%	100	0.0%	-	100	-	100	-	(800)
14	1,000	10.0%	100	0.0%	-	100	-	100	-	(900)
15	1,000	10.0%	100	0.0%	-	100	-	100	1,000	-
16	1,000	10.0%	100	0.0%	-	100	-	100	-	(100)
			\$ 1,600		\$ -	\$ 1,600	\$ 500	\$ 2,100	\$ 1,500	

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 10



1 **Scenario 4 Calculations:**

2 **Base Depreciation Rate:**  $(1 / \text{Average Service Life}) = (1 / 10) = 10\%$

3

4 **Asset Retirement Calculations:** Gains and losses on disposition of assets are recognized  
5 immediately in this scenario. Accumulated depreciation retired is calculated as Cost of  
6 item(s) retired x depreciation rate in use x number of years depreciated:

- 7 - Year 5:  $\$500 \times 10\% \times 5 \text{ years} = \$250$  accumulated depreciation, \$250 loss.  
8 - Year 10:  $\$500 \times 10\% \times 5 \text{ years} = \$250$  accumulated depreciation, \$250 loss.  
9 - Year 15: [Group 1:  $\$500 \times 10\% \times 5 \text{ years} = \$250$  accumulated depreciation, \$250  
10 loss] plus [Group 2:  $\$500 \times 10\% \times 15 \text{ years}$ ] = \$750 accumulated depreciation,  
11 \$250 gain]

12 **Depreciation Adjustment – True-up Rates:** There is no need for a true-up rate in this  
13 scenario to correct depreciation expense, as the accumulated depreciation balance at the  
14 end of each 5 year interval matches the expected accumulated balance as calculated for  
15 Scenario 2:

- 16 - Year 5: \$ (250)  
17 - Year 10: \$ (500)  
18 - Year 15: \$ 0

19 **Suitability for Use in Rate Setting:** From a rate setting perspective, this scenario is  
20 deficient for the following reasons:

- 21 - The pattern of expense recognition is very uneven, with large corrections required  
22 in years 5 and 10.  
23 - Although there is an equal availability and use of assets in each year, the expense  
24 pattern does not reflect that, as higher expense recognition in years 1 – 10 as  
25 compared to years 11 – 15  
26 o Expense for years 1 – 5 equals \$750  
27 o Expense in years 6 – 10 equals \$750  
28 o Expense in years 11 – 15 equals \$500

29

30 **IFRS Compliance:** In Scenario 4, a loss is realized on the retirement of assets with lives  
31 shorter than the average and a gain is realized on the retirement of assets with lives longer  
32 than the average. Scenario 4 fails to meet IFRS requirements as the pattern of depreciation  
33 expense is not true to the expected useful lives of the items included in the group, which is  
34 evident from the fact that none of the assets in this scenario are fully depreciated when  
35 retired. Those with a 5 year life are under-depreciated when retired and those with a 15  
36 year life are over-depreciated.