Volume 6 - Board Counsel's Book of Documents **Exhibit#_________**
Manitoba Hydro 2014/15 and 2015/16 GRA

Tab #	Description	Reference
Depreciation & Amortization		
1	Depreciation Expense - Detail	Tab 5, p. 27, Schedule 5.1.6; PUB/MH I-27 (a)
2	Depreciation Rates	PUB/MH I-46 (a) Appendix 5.6, pp. 7-14
3	Depreciation Continuity	MIPUG/MH I-19 (a) & (b)
4	IFRS Accounting Changes	COALITION/MH I-49 MIPUG/MH I-15 PUB/MH I-37 (b) & (c) PUB/MH II-21 PUB/MH II-54 MIPUG/MH-I-18
5	Group Accounting Methodologies - ASL vs. ELG	PUB/MH I-42 PUB/MIPUG-17 CAC/MH I-47 (a) (2012 GRA) MIPUG/MH I-14 (d) PUB/MH II-69 PUB/MH I-42 (b) MIPUG/MH II-20
6	Depreciation Options – ASL w/o Net Salvage	MIPUG/MH I-22 PUB/MH II-33 PUB/MH II-25
7	Asset Retirement	PUB/MH II-60 PUB/MH II-29
8	Depreciation Options – IFRS Compliant ASL	Order 43-13 Excerpt Correspondence Compliance with Directives 8 & 9 Order 43-13 Appendix 11.49 Excerpts PUB/MH II-56 PUB/MH II-57 MIPUG-MH I-16 PUB/MH II-59
9	Surplus of Book Accumulated Depreciation	Appendix 5.6, Attachment 1 MIPUG/MH I-22 (b) Attachment 1 MIPUG/MH-I-20 Appendix 5.6, Attachment 2

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Tab #	**Description**	**Reference**
10.	MIPUG Evidence P. Bowman Intergenerational Issue ASL vs. ELG	PUB/MIPUG (Bowman) 16
11.	Crown Owned Canadian Utilities using ASL	PUB/MIPUG (Bowman) 17
12	Characteristics of ELG vs. ASL Methodology	PUB/MIPUG (Lee) 2
13	Sensitivity of ASL vs. ELG to changes in selected Iowa Curves	PUB/MIPUG (Lee) 4
14	Extrapolation Analysis / Requirement for componentization for ASL rates.	PUB/MIPUG (Lee) 8
15	Permissibility of Net Salvage Recovery Under IRS	Order 43/13 Excerpt 2012/13 and 2013/14 GRA Transcript Excerpts

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Please see the following schedule for a breakdown of Depreciation and Amortization.

MANITOBA HYDRO | **Schedule 5.1.6**
DEPRECIATION AND AMORTIZATION EXPENSE | **(000's)**

	2012/13 Actual	2013/14 Actual	2014/15 Forecast	2015/16 Forecast	2016/17 Forecast
Generation					
Hydraulic Generating Stations	80 110	82 678	92 953	92 265	96 041
Thermal Generating Stations	15 415	15 562	15 770	15 755	15 856
Demand Side Management	28 217	30 262	31 576	34 957	37 501
Diesel Generating Stations	1 457	1 757	2 342	2 557	2 111
Wuskwatim	16 179	26 688	26 651	26 984	27 082
Amortization of Contributions	(841)	(868)	(1 049)	(1 146)	(1 146)
	$ 140 537	$ 156 079	$ 168 244	$ 171 373	$ 177 446
Transmission					
Transmission	14 571	16 644	15 929	13 369	14 367
Amortization of Contributions	(1 358)	(3 204)	(3 051)	(3 054)	(3 059)
	$ 13 213	$ 13 440	$ 12 879	$ 10 315	$ 11 308
Stations					
Substations	82 493	86 122	87 617	85 735	90 177
Transformers	1 806	1 940	1 627	1 597	1 828
Amortization of Contributions	(1 247)	(4 457)	(4 402)	(4 402)	(4 402)
	$ 83 052	$ 83 605	$ 84 842	$ 82 930	$ 87 603
Distribution					
Subtransmission Lines	6 271	6 629	7 376	6 948	7 401
Distribution Lines	58 170	61 337	60 509	56 989	60 951
Meters & Transformers	4 273	4 260	2 848	3 281	3 404
Amortization of Contributions	(5 084)	(5 476)	(5 699)	(6 409)	(7 009)
	$ 63 630	$ 66 750	$ 65 034	$ 60 809	$ 64 747
Other					
Communications	19 192	21 307	16 819	17 765	18 206
Motor Vehicles	10 954	11 573	10 154	11 819	12 226
Structures & Improvements	7 947	8 066	7 928	8 800	9 557
General Equipment	25 806	23 255	16 627	16 780	16 797
Computer Development	20 582	19 667	17 687	18 487	20 816
Conawapa	-	-	-	-	7 711
Affordable Energy Fund	5 406	4 410	5 270	4 290	1 509
Miscellaneous	3 550	4 628	1 701	2 652	3 269
Corporate Allocation	(1 946)	(1 946)	(1 974)	(1 850)	(1 853)
Target Adjustment	-	-	(621)	(3 305)	(6 938)
	$ 91 491	$ 90 960	$ 73 591	$ 75 439	$ 81 300
Total D&A Expense Including Accounting Changes	$ 391 923	$ 410 834	$ 404 590	$ 400 866	$ 422 404
Add: Accounting Policy & Estimate Changes	-	-	**24 923**	**52 685**	**57 159**
Total D&A Expense Excluding Accounting Changes	$ 391 923	$ 410 834	$ 429 512	$ 453 551	$ 479 563
Year over year % change Including Accounting Changes		4.8%	-1.5%	-0.9%	5.4%
Year over year % change Excluding Accounting Changes		**4.8%**	**4.5%**	**5.6%**	**5.7%**

Section:	Tab 5: Section 5.7, Schedule 5.1.6	**Page No.:**	27
Topic:	Financial Results & Forecasts		
Subtopic:	Amortization Expense		
Issue:	Amortization Expense Detail		

PREAMBLE TO IR (IF ANY):

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QUESTION:

Please provide a breakdown by major component of rate regulated amortization expense in similar detail to CAC/MH I-14 (f) (2012 GRA) for 2012/13 through 2016/17 and indicate where the expenditures are included in the detail of depreciation and amortization expense in Schedule 5.1.6.

RATIONALE FOR QUESTION:

To understand how rate regulated balances, including Conawapa, impact revenue requirement in the application.

RESPONSE:

Please see the following table for a breakdown by major component and expenditure category in Schedule 5.1.6.

MANITOBA HYDRO
RATE REGULATED AMORTIZATION EXPENSE (000's)

	Schedule 5.1.6 Categorization	2012/13 Actual	2013/14 Actual	2014/15 Forecast	2015/16 Forecast	2016/17 Forecast
Regulated Assets						
Power Smart programs - Electric	Generation - Demand Side Management	28 217	30 262	31 576	34 957	37 501
Conawapa	Other - Conawapa					7 711
Site Restoration Costs - General	Other - Miscellaneous	1 924	1 991	2 126	2 179	2 223
Site Restoration Costs - Diesel	Other - Miscellaneous	1 556	1 634	1 665	1 555	1 498
Acquisition Costs	Other - Miscellaneous	692	692	692	692	692
Regulatory Costs	Other - Miscellaneous	2 622	2 572	27	765	1 307
		$ 35 011	$ 37 151	$ 36 086	$ 40 149	$ 50 933

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Section:	Tab 5: Schedule 5.1.6 Appendix 5.6 pg.7	Page No.:	7
Topic:	Financial Results & Forecasts		
Subtopic:	Depreciation & Amortization		
Issue:	Depreciation Rate Changes		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please update the depreciable group table to include two additional columns including Previous Expected Life, and Change in Expected Life.

RATIONALE FOR QUESTION:

To assess changes in the depreciation study from the last depreciation study.

RESPONSE:

Please see the attached depreciable group table for the additional columns including Previous Expected Life and Change in Expected Life.

Depreciation Rate Tables (Electric operations)

DEPRECIABLE GROUP (Electric Operations)	Previous Expected Service Life	2014 Expected Service Life	Change in Expected Life
HYDRAULIC GENERATION			
GREAT FALLS			
DAMS, DYKES AND WEIRS	125	125	-
POWERHOUSE	125	125	-
POWERHOUSE RENOVATIONS	25	40	15
SPILLWAY	75	80	5
WATER CONTROL SYSTEMS	50	65	15
ROADS AND SITE IMPROVEMENTS	50	50	-
TURBINES AND GENERATORS	65	60	(5)
GOVERNORS AND EXCITATION SYSTEM	50	50	-
LICENCE RENEWAL	50	50	-
A/C ELECTRICAL POWER SYSTEMS	50	55	5
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	23	25	2
AUXILIARY STATION PROCESSES	40	50	10
SUPPORT BUILDINGS	65	65	-
SUPPORT BUILDING RENOVATIONS	20	20	-
POINTE DU BOIS - Original			
DAMS, DYKES AND WEIRS	125	125	-
POWERHOUSE	125	125	-
POWERHOUSE RENOVATIONS	25	40	15
SPILLWAY	75	80	5
WATER CONTROL SYSTEMS	50	65	15
ROADS AND SITE IMPROVEMENTS	50	50	-
TURBINES AND GENERATORS	65	60	(5)
GOVERNORS AND EXCITATION SYSTEM	50	50	-
LICENCE RENEWAL	50	50	-
A/C ELECTRICAL POWER SYSTEMS	50	55	5
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	23	25	2
AUXILIARY STATION PROCESSES	40	50	10
SUPPORT BUILDINGS	65	65	-
SUPPORT BUILDING RENOVATIONS	20	20	-
POINTE DU BOIS - New			
DAMS, DYKES AND WEIRS		125	New
SPILLWAY	75	80	5
WATER CONTROL SYSTEMS		65	New
ROADS AND SITE IMPROVEMENTS		50	New
A/C ELECTRICAL POWER SYSTEMS		55	New
INSTRUMENTATION, CONTROL AND D/C SYSTEMS		25	New
AUXILIARY STATION PROCESSES		50	New
SUPPORT BUILDINGS		65	New
SUPPORT BUILDING RENOVATIONS		20	New
SEVEN SISTERS			
DAMS, DYKES AND WEIRS	125	125	-
POWERHOUSE	125	125	-
POWERHOUSE RENOVATIONS	25	40	15
SPILLWAY	75	80	5
WATER CONTROL SYSTEMS	50	65	15
ROADS AND SITE IMPROVEMENTS	50	50	-
TURBINES AND GENERATORS	65	60	(5)
GOVERNORS AND EXCITATION SYSTEM	50	50	-
LICENCE RENEWAL	50	50	-
A/C ELECTRICAL POWER SYSTEMS	50	55	5
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	23	25	2
AUXILIARY STATION PROCESSES	40	50	10
SUPPORT BUILDINGS	65	65	-
SUPPORT BUILDING RENOVATIONS	20	20	-

DEPRECIABLE GROUP (Electric Operations)	Previous Expected Service Life	2014 Expected Service Life	Change in Expected Life
SLAVE FALLS			
DAMS, DYKES AND WEIRS	125	125	-
POWERHOUSE	125	125	-
POWERHOUSE RENOVATIONS	25	40	15
SPILLWAY	75	80	5
WATER CONTROL SYSTEMS	50	65	15
ROADS AND SITE IMPROVEMENTS	50	50	-
TURBINES AND GENERATORS	65	60	(5)
GOVERNORS AND EXCITATION SYSTEM	50	50	-
LICENCE RENEWAL	50	50	-
A/C ELECTRICAL POWER SYSTEMS	50	55	5
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	23	25	2
AUXILIARY STATION PROCESSES	40	50	10
SUPPORT BUILDINGS	65	65	-
SUPPORT BUILDING RENOVATIONS	20	20	-
PINE FALLS			
DAMS, DYKES AND WEIRS	125	125	-
POWERHOUSE	125	125	-
POWERHOUSE RENOVATIONS	25	40	15
SPILLWAY	75	80	5
WATER CONTROL SYSTEMS	50	65	15
ROADS AND SITE IMPROVEMENTS	50	50	-
TURBINES AND GENERATORS	65	60	(5)
GOVERNORS AND EXCITATION SYSTEM	50	50	-
LICENCE RENEWAL	50	50	-
A/C ELECTRICAL POWER SYSTEMS	50	55	5
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	23	25	2
AUXILIARY STATION PROCESSES	40	50	10
SUPPORT BUILDINGS	65	65	-
SUPPORT BUILDING RENOVATIONS	20	20	-
COMMUNITY DEVELOPMENT COSTS	81	78	(3)
MCARTHUR FALLS			
DAMS, DYKES AND WEIRS	125	125	-
POWERHOUSE	125	125	-
POWERHOUSE RENOVATIONS	25	40	15
SPILLWAY	75	80	5
WATER CONTROL SYSTEMS	50	65	15
ROADS AND SITE IMPROVEMENTS	50	50	-
TURBINES AND GENERATORS	65	60	(5)
GOVERNORS AND EXCITATION SYSTEM	50	50	-
LICENCE RENEWAL	50	50	-
A/C ELECTRICAL POWER SYSTEMS	50	55	5
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	23	25	2
AUXILIARY STATION PROCESSES	40	50	10
SUPPORT BUILDINGS	65	65	-
SUPPORT BUILDING RENOVATIONS	20	20	-

DEPRECIABLE GROUP (Electric Operations)	Previous Expected Service Life	2014 Expected Service Life	Change in Expected Life
KELSEY			
DAMS, DYKES AND WEIRS	125	125	-
POWERHOUSE	125	125	-
POWERHOUSE RENOVATIONS	25	40	15
SPILLWAY	75	80	5
WATER CONTROL SYSTEMS	50	65	15
ROADS AND SITE IMPROVEMENTS	50	50	-
TURBINES AND GENERATORS	65	60	(5)
GOVERNORS AND EXCITATION SYSTEM	50	50	-
LICENCE RENEWAL	50	50	-
A/C ELECTRICAL POWER SYSTEMS	50	55	5
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	23	25	2
AUXILIARY STATION PROCESSES	40	50	10
SUPPORT BUILDINGS	65	65	-
SUPPORT BUILDING RENOVATIONS	20	20	-
GRAND RAPIDS			
DAMS, DYKES AND WEIRS	125	125	-
POWERHOUSE	125	125	-
POWERHOUSE RENOVATIONS	25	40	15
SPILLWAY	75	80	5
WATER CONTROL SYSTEMS	50	65	15
ROADS AND SITE IMPROVEMENTS	50	50	-
TURBINES AND GENERATORS	65	60	(5)
GOVERNORS AND EXCITATION SYSTEM	50	50	-
LICENCE RENEWAL	50	50	-
A/C ELECTRICAL POWER SYSTEMS	50	55	5
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	23	25	2
AUXILIARY STATION PROCESSES	40	50	10
SUPPORT BUILDINGS	65	65	-
SUPPORT BUILDING RENOVATIONS	20	20	-
COMMUNITY DEVELOPMENT COSTS ***	80	79	(1)
KETTLE			
DAMS, DYKES AND WEIRS	125	125	-
POWERHOUSE	125	125	-
POWERHOUSE RENOVATIONS	25	40	15
SPILLWAY	75	80	5
WATER CONTROL SYSTEMS	50	65	15
ROADS AND SITE IMPROVEMENTS	50	50	-
TURBINES AND GENERATORS	65	60	(5)
GOVERNORS AND EXCITATION SYSTEM	50	50	-
LICENCE RENEWAL	50	50	-
A/C ELECTRICAL POWER SYSTEMS	50	55	5
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	23	25	2
AUXILIARY STATION PROCESSES	40	50	10
SUPPORT BUILDINGS	65	65	-
SUPPORT BUILDING RENOVATIONS	20	20	-

DEPRECIABLE GROUP (Electric Operations)	Previous Expected Service Life	2014 Expected Service Life	Change in Expected Life
LAURIE RIVER			
DAMS, DYKES AND WEIRS	125	125	-
POWERHOUSE	125	125	-
POWERHOUSE RENOVATIONS	25	40	15
SPILLWAY	75	80	5
WATER CONTROL SYSTEMS	50	65	15
ROADS AND SITE IMPROVEMENTS	50	50	-
TURBINES AND GENERATORS	65	60	(5)
GOVERNORS AND EXCITATION SYSTEM	50	50	-
LICENCE RENEWAL	50	50	-
A/C ELECTRICAL POWER SYSTEMS	50	55	5
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	23	25	2
AUXILIARY STATION PROCESSES	40	50	10
SUPPORT BUILDINGS	65	65	-
SUPPORT BUILDING RENOVATIONS	20	20	-
JENPEG			
DAMS, DYKES AND WEIRS	125	125	-
POWERHOUSE	125	125	-
POWERHOUSE RENOVATIONS	25	40	15
SPILLWAY	75	80	5
WATER CONTROL SYSTEMS	50	65	15
ROADS AND SITE IMPROVEMENTS	50	50	-
TURBINES AND GENERATORS	65	60	(5)
GOVERNORS AND EXCITATION SYSTEM	50	50	-
LICENCE RENEWAL	50	50	-
A/C ELECTRICAL POWER SYSTEMS	50	55	5
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	23	25	2
AUXILIARY STATION PROCESSES	40	50	10
SUPPORT BUILDINGS	65	65	-
SUPPORT BUILDING RENOVATIONS	20	20	-
LAKE WINNIPEG REGULATION			
DAMS, DYKES AND WEIRS	125	125	-
LICENCE RENEWAL	50	50	-
COMMUNITY DEVELOPMENT COSTS	100	85	(15)
CHURCHILL RIVER DIVERSION			
DAMS, DYKES AND WEIRS	125	125	-
SPILLWAY	75	80	5
WATER CONTROL SYSTEMS	50	65	15
ROADS AND SITE IMPROVEMENTS	50	50	-
LICENCE RENEWAL	50	50	-
A/C ELECTRICAL POWER SYSTEMS	50	55	5
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	23	25	2
AUXILIARY STATION PROCESSES	40	50	10
SUPPORT BUILDINGS	65	65	-
SUPPORT BUILDING RENOVATIONS	20	20	-
COMMUNITY DEVELOPMENT COSTS	100	90	(10)

DEPRECIABLE GROUP (Electric Operations)	Previous Expected Service Life	2014 Expected Service Life	Change in Expected Life
LONG SPRUCE			
DAMS, DYKES AND WEIRS	125	125	-
POWERHOUSE	125	125	-
POWERHOUSE RENOVATIONS	25	40	15
SPILLWAY	75	80	5
WATER CONTROL SYSTEMS	50	65	15
ROADS AND SITE IMPROVEMENTS	50	50	-
TURBINES AND GENERATORS	65	60	(5)
GOVERNORS AND EXCITATION SYSTEM	50	50	-
LICENCE RENEWAL	50	50	-
A/C ELECTRICAL POWER SYSTEMS	50	55	5
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	23	25	2
AUXILIARY STATION PROCESSES	40	50	10
SUPPORT BUILDINGS	65	65	-
SUPPORT BUILDING RENOVATIONS	20	20	-
LIMESTONE			
DAMS, DYKES AND WEIRS	125	125	-
POWERHOUSE	125	125	-
POWERHOUSE RENOVATIONS	25	40	15
SPILLWAY	75	80	5
WATER CONTROL SYSTEMS	50	65	15
ROADS AND SITE IMPROVEMENTS	50	50	-
TURBINES AND GENERATORS	65	60	(5)
GOVERNORS AND EXCITATION SYSTEM	50	50	-
LICENCE RENEWAL	50	50	-
A/C ELECTRICAL POWER SYSTEMS	50	55	5
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	23	25	2
AUXILIARY STATION PROCESSES	40	50	10
SUPPORT BUILDINGS	65	65	-
SUPPORT BUILDING RENOVATIONS	20	20	-
WUSKWATIM			
DAMS, DYKES AND WEIRS	125	125	-
POWERHOUSE	125	125	-
POWERHOUSE RENOVATIONS	25	40	15
SPILLWAY	75	80	5
WATER CONTROL SYSTEMS	50	65	15
ROADS AND SITE IMPROVEMENTS	50	50	-
TURBINES AND GENERATORS	65	60	(5)
GOVERNORS AND EXCITATION SYSTEM	50	50	-
A/C ELECTRICAL POWER SYSTEMS	50	55	5
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	23	25	2
AUXILIARY STATION PROCESSES	40	50	10
SUPPORT BUILDINGS	65	65	-
SUPPORT BUILDING RENOVATIONS	20	20	-
INFRASTRUCTURE SUPPORTING GENERATION			
PROVINCIAL ROADS	50	50	-
TOWN SITE BUILDING	65	55	(10)
TOWN SITE BUILDINGS RENOVATIONS	20	20	-
TOWN SITE OTHER INFRASTRUCTURE	45	45	-

DEPRECIABLE GROUP (Electric Operations)	Previous Expected Service Life	2014 Expected Service Life	Change in Expected Life
THERMAL GENERATION			
BRANDON UNIT 5 (COAL)			
POWERHOUSE	65	75	10
POWERHOUSE RENOVATIONS	25	40	15
ROADS AND SITE IMPROVEMENTS	50	50	-
THERMAL TURBINES AND GENERATORS	50	60	10
GOVERNORS AND EXCITATION SYSTEM	50	50	-
STEAM GENERATOR AND AUXILIARIES	65	60	(5)
LICENCE RENEWAL	50	50	-
A/C ELECTRICAL POWER SYSTEMS	50	55	5
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	23	25	2
AUXILIARY STATION PROCESSES	40	50	10
SUPPORT BUILDINGS	65	65	-
SUPPORT BUILDING RENOVATIONS	20	20	-
BRANDON UNITS 6 AND 7			
POWERHOUSE	65	75	10
POWERHOUSE RENOVATIONS	25	40	15
THERMAL TURBINES AND GENERATORS	50	60	10
GOVERNORS AND EXCITATION SYSTEM	50	50	-
COMBUSTION TURBINE	25	25	-
LICENCE RENEWAL	50	50	-
COMBUSTION TURBINE OVERHAULS	10	15	5
A/C ELECTRICAL POWER SYSTEMS	50	55	5
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	23	25	2
AUXILIARY STATION PROCESSES	40	50	10
SELKIRK			
POWERHOUSE	65	75	10
POWERHOUSE RENOVATIONS	25	40	15
ROADS AND SITE IMPROVEMENTS	50	50	-
THERMAL TURBINES AND GENERATORS	50	60	10
GOVERNORS AND EXCITATION SYSTEM	50	50	-
STEAM GENERATOR AND AUXILIARIES	65	60	(5)
LICENCE RENEWAL	50	50	-
A/C ELECTRICAL POWER SYSTEMS	50	55	5
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	23	25	2
AUXILIARY STATION PROCESSES	40	50	10
SUPPORT BUILDINGS	65	65	-
SUPPORT BUILDING RENOVATIONS	20	20	-

DEPRECIABLE GROUP (Electric Operations)	Previous Expected Service Life	2014 Expected Service Life	Change in Expected Life
DIESEL GENERATION			
BUILDINGS	30	25	(5)
BUILDING RENOVATIONS	15	15	-
ENGINES AND GENERATORS - OVERHAULS	5	4	(1)
ENGINES AND GENERATORS	25	22	(3)
ACCESSORY STATION EQUIPMENT	20	20	-
FUEL STORAGE AND HANDLING	30	25	(5)
TRANSMISSION			
ROADS, TRAILS AND BRIDGES	45	50	5
METAL TOWERS AND CONCRETE POLES	85	85	-
POLES AND FIXTURES	55	55	-
GROUND LINE TREATMENT	10	10	-
OVERHEAD CONDUCTOR AND DEVICES	65	80	15
UNDERGROUND CABLE AND DEVICES	45	45	-
COMMUNITY DEVELOPMENT COSTS		79	New
SUBSTATIONS			
BUILDINGS	65	65	-
BUILDING RENOVATIONS	20	20	-
ROADS, STEEL STRUCTURES AND CIVIL SITE WORK	50	50	-
POLES AND FIXTURES	40	45	5
POWER TRANSFORMERS	50	50	-
OTHER TRANSFORMERS	35	50	15
INTERRUPTING EQUIPMENT	45	50	5
OTHER STATION EQUIPMENT	43	45	2
ELECTRONIC EQUIPMENT AND BATTERIES	20	25	5
SYNCHRONOUS CONDENSERS AND UNIT TRANSFORMERS	65	65	-
SYNCHRONOUS CONDENSER OVERHAULS	15	15	-
HVDC CONVERTER EQUIPMENT	25	30	5
HVDC SERIALIZED EQUIPMENT	25	30	5
HVDC ACCESSORY STATION EQUIPMENT	37	36	(1)
HVDC ELECTRONIC EQUIPMENT AND BATTERIES	20	25	5
DISTRIBUTION			
CONCRETE DUCTLINE AND MANHOLES	75	75	-
CONCRETE DUCTLINE AND MANHOLE REFURBISHMENTS	50	30	(20)
METAL TOWERS	50	60	10
POLES AND FIXTURES	55	65	10
GROUND LINE TREATMENT	10	12	2
OVERHEAD CONDUCTOR AND DEVICES	60	60	-
UNDERGROUND CABLE AND DEVICES - 66 KV	70	60	(10)
UNDERGROUND CABLE AND DEVICES - PRIMARY	60	60	-
UNDERGROUND CABLE AND DEVICES - SECONDARY	45	44	(1)
SERIALIZED EQUIPMENT - OVERHEAD	35	45	10
DSC - HIGH VOLTAGE TRANSFORMERS	50	50	-
SERIALIZED EQUIPMENT - UNDERGROUND	40	42	2
ELECTRONIC EQUIPMENT	10	10	-
SERVICES	30	35	5
STREET LIGHTING	35	45	10

DEPRECIABLE GROUP (Electric Operations)	Previous Expected Service Life	2014 Expected Service Life	Change in Expected Life
METERS			
METERS - ELECTRONIC	20	15	(5)
METERS - ANALOG	25	26	1
METERING EXCHANGES		15	New
METERING TRANSFORMERS	40	50	10
COMMUNICATION			
BUILDINGS	65	65	-
BUILDING RENOVATIONS	20	20	-
BUILDING - SYSTEM CONTROL CENTRE	65	75	10
COMMUNICATION TOWERS	60	60	-
FIBRE OPTIC AND METALLIC CABLE	35	35	-
CARRIER EQUIPMENT	15	20	5
OPERATIONAL IT EQUIPMENT	5	5	-
MOBILE RADIO, TELEPHONE AND VIDEO CONFERENCING	8	8	-
OPERATIONAL DATA NETWORK	8	8	-
POWER SYSTEM CONTROL	10	15	5
MOTOR VEHICLES			
PASSENGER VEHICLES	9	11	2
LIGHT TRUCKS	10	12	2
HEAVY TRUCKS	15	19	4
CONSTRUCTION EQUIPMENT	15	23	8
LARGE SOFT-TRACK EQUIPMENT	22	27	5
TRAILERS	35	35	-
MISCELLANEOUS VEHICLES	10	13	3
BUILDINGS			
BUILDINGS - GENERAL	65	65	-
BUILDING RENOVATIONS	20	20	-
BUILDING - 360 PORTAGE - CIVIL	100	100	-
BUILDING - 360 PORTAGE - ELECTRO/MECHANICAL	45	45	-
LEASEHOLD IMPROVEMENTS - SONY PLACE		10	New
GENERAL EQUIPMENT			
TOOLS, SHOP AND GARAGE EQUIPMENT	15	15	-
COMPUTER EQUIPMENT	5	5	-
OFFICE FURNITURE AND EQUIPMENT	20	20	-
HOT WATER TANKS	6	6	-
EASEMENTS			
EASEMENTS	75	75	-
COMPUTER SOFTWARE AND DEVELOPMENT			
COMPUTER DEVELOPMENT - MAJOR SYSTEMS	10	11	1
COMPUTER DEVELOPMENT - SMALL SYSTEMS	10	10	-
COMPUTER SOFTWARE - GENERAL	5	5	-
COMPUTER SOFTWARE - COMMUNICATION/OPERATIONAL	5	5	-
OPERATIONAL SYSTEM MAJOR SOFTWARE - EMS/SCADA	6	7	1

Depreciation Rate Schedules (Electric operations)

DEPRECIABLE GROUP (Electric Operations)	Expected Service Life	2014-15 Previous ASL Rate %	2014-15 Approved ASL Rate %	2015-16 Approved ELG Rate %
HYDRAULIC GENERATION				
GREAT FALLS				
DAMS, DYKES AND WEIRS	125	1.28	1.32	1.12
POWERHOUSE	125	1.27	1.28	1.07
POWERHOUSE RENOVATIONS	40	4.40	2.67	2.41
SPILLWAY	80	1.59	1.50	1.35
WATER CONTROL SYSTEMS	65	2.07	1.52	1.35
ROADS AND SITE IMPROVEMENTS	50	2.33	2.42	2.42
TURBINES AND GENERATORS	60	1.82	2.25	2.03
GOVERNORS AND EXCITATION SYSTEM	50	2.11	2.25	2.06
LICENCE RENEWAL	50	2.00	2.04	2.04
A/C ELECTRICAL POWER SYSTEMS	55	2.10	1.84	1.67
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	4.43	3.86	3.79
AUXILIARY STATION PROCESSES	50	2.59	2.03	2.10
SUPPORT BUILDINGS	65	1.73	1.69	1.36
SUPPORT BUILDING RENOVATIONS	20	5.50	5.50	5.00
POINTE DU BOIS - Original				
DAMS, DYKES AND WEIRS	125	3.63	3.10	2.70
POWERHOUSE	125	4.39	2.94	2.55
POWERHOUSE RENOVATIONS	40	5.24	4.10	3.71
SPILLWAY	80	10.76	84.53	73.37
WATER CONTROL SYSTEMS	65	3.35	2.11	1.73
ROADS AND SITE IMPROVEMENTS	50	3.36	4.09	3.80
TURBINES AND GENERATORS	60	4.04	2.84	2.44
GOVERNORS AND EXCITATION SYSTEM	50	5.24	4.02	3.68
LICENCE RENEWAL	50	4.76	3.85	3.85
A/C ELECTRICAL POWER SYSTEMS	55	4.58	3.16	2.78
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	5.12	4.30	4.26
AUXILIARY STATION PROCESSES	50	4.03	3.71	3.59
SUPPORT BUILDINGS	65	2.93	2.99	2.59
SUPPORT BUILDING RENOVATIONS	20	5.50	4.47	3.84
POINTE DU BOIS - New				
DAMS, DYKES AND WEIRS	125	-	0.91	0.85
SPILLWAY	80	1.47	1.37	1.49
WATER CONTROL SYSTEMS	65	-	1.69	1.64
ROADS AND SITE IMPROVEMENTS	50	-	2.20	2.36
A/C ELECTRICAL POWER SYSTEMS	55	-	2.40	1.94
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	-	4.40	4.54
AUXILIARY STATION PROCESSES	50	-	2.20	3.01
SUPPORT BUILDINGS	65	-	1.69	1.65
SUPPORT BUILDING RENOVATIONS	20	-	5.50	5.00
SEVEN SISTERS				
DAMS, DYKES AND WEIRS	125	1.03	1.06	0.90
POWERHOUSE	125	0.90	0.91	0.74
POWERHOUSE RENOVATIONS	40	4.40	2.67	2.41
SPILLWAY	80	1.17	1.36	1.17
WATER CONTROL SYSTEMS	65	1.80	1.25	1.02
ROADS AND SITE IMPROVEMENTS	50	1.84	1.78	1.30
TURBINES AND GENERATORS	60	1.64	1.84	1.69
GOVERNORS AND EXCITATION SYSTEM	50	2.00	2.22	2.12
LICENCE RENEWAL	50	2.00	2.00	2.00
A/C ELECTRICAL POWER SYSTEMS	55	1.91	1.74	1.56
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	3.73	3.80	3.44
AUXILIARY STATION PROCESSES	50	2.13	1.91	2.03
SUPPORT BUILDINGS	65	1.74	1.65	1.52
SUPPORT BUILDING RENOVATIONS	20	5.50	5.50	5.00

DEPRECIABLE GROUP (Electric Operations)	Expected Service Life	2014-15 Previous ASL Rate %	2014-15 Approved ASL Rate %	2015-16 Approved ELG Rate %
SLAVE FALLS				
DAMS, DYKES AND WEIRS	125	1.69	1.71	1.54
POWERHOUSE	125	1.58	1.59	1.43
POWERHOUSE RENOVATIONS	40	4.40	2.75	2.50
SPILLWAY	80	1.87	1.82	1.74
WATER CONTROL SYSTEMS	65	2.18	1.77	1.65
ROADS AND SITE IMPROVEMENTS	50	2.20	2.30	2.36
TURBINES AND GENERATORS	60	1.79	1.91	1.81
GOVERNORS AND EXCITATION SYSTEM	50	2.20	2.22	2.12
LICENCE RENEWAL	50	2.00	2.00	2.00
A/C ELECTRICAL POWER SYSTEMS	55	2.21	2.00	1.91
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	4.72	4.42	4.56
AUXILIARY STATION PROCESSES	50	2.73	2.34	2.70
SUPPORT BUILDINGS	65	1.81	2.01	1.89
SUPPORT BUILDING RENOVATIONS	20	5.50	5.50	5.00
PINE FALLS				
DAMS, DYKES AND WEIRS	125	1.17	1.23	1.12
POWERHOUSE	125	0.83	0.83	0.71
POWERHOUSE RENOVATIONS	40	4.40	2.67	2.41
SPILLWAY	80	1.60	1.50	1.49
WATER CONTROL SYSTEMS	65	1.95	1.28	1.06
ROADS AND SITE IMPROVEMENTS	50	1.81	1.68	1.61
TURBINES AND GENERATORS	60	1.47	1.62	1.37
GOVERNORS AND EXCITATION SYSTEM	50	2.20	2.20	2.13
LICENCE RENEWAL	50	2.00	2.00	2.00
A/C ELECTRICAL POWER SYSTEMS	55	2.06	1.83	1.58
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	4.25	4.17	4.04
AUXILIARY STATION PROCESSES	50	2.54	1.78	1.81
SUPPORT BUILDINGS	65	1.61	1.62	1.56
SUPPORT BUILDING RENOVATIONS	20	5.50	5.50	5.00
COMMUNITY DEVELOPMENT COSTS	78	1.17	1.28	1.28
MCARTHUR FALLS				
DAMS, DYKES AND WEIRS	125	0.91	1.12	1.00
POWERHOUSE	125	0.83	0.84	0.72
POWERHOUSE RENOVATIONS	40	4.40	2.67	2.41
SPILLWAY	80	1.19	1.19	0.97
WATER CONTROL SYSTEMS	65	2.06	1.37	1.25
ROADS AND SITE IMPROVEMENTS	50	1.99	1.94	1.71
TURBINES AND GENERATORS	60	1.06	1.35	0.94
GOVERNORS AND EXCITATION SYSTEM	50	2.10	2.08	1.94
LICENCE RENEWAL	50	2.00	2.00	2.00
A/C ELECTRICAL POWER SYSTEMS	55	1.90	1.72	1.32
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	4.29	3.62	2.74
AUXILIARY STATION PROCESSES	50	2.58	1.82	1.85
SUPPORT BUILDINGS	65	1.63	1.73	1.67
SUPPORT BUILDING RENOVATIONS	20	5.50	5.50	5.00

DEPRECIABLE GROUP (Electric Operations)	Expected Service Life	2014-15 Previous ASL Rate %	2014-15 Approved ASL Rate %	2015-16 Approved ELG Rate %
KELSEY				
DAMS, DYKES AND WEIRS	125	1.05	1.13	1.03
POWERHOUSE	125	0.89	1.18	1.08
POWERHOUSE RENOVATIONS	40	4.40	2.75	2.50
SPILLWAY	80	1.34	1.71	1.58
WATER CONTROL SYSTEMS	65	2.09	1.70	1.61
ROADS AND SITE IMPROVEMENTS	50	2.05	2.44	2.30
TURBINES AND GENERATORS	60	1.68	1.90	1.85
GOVERNORS AND EXCITATION SYSTEM	50	2.14	2.25	2.17
LICENCE RENEWAL	50	2.00	2.00	2.00
A/C ELECTRICAL POWER SYSTEMS	55	2.03	2.11	2.03
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	4.58	4.67	4.62
AUXILIARY STATION PROCESSES	50	2.63	2.19	2.31
SUPPORT BUILDINGS	65	1.67	1.79	1.73
SUPPORT BUILDING RENOVATIONS	20	4.98	4.98	4.44
GRAND RAPIDS				
DAMS, DYKES AND WEIRS	125	0.98	1.01	0.90
POWERHOUSE	125	0.91	0.92	0.81
POWERHOUSE RENOVATIONS	40	4.40	2.55	2.28
SPILLWAY	80	1.30	1.28	1.15
WATER CONTROL SYSTEMS	65	1.79	1.10	0.99
ROADS AND SITE IMPROVEMENTS	50	1.68	1.63	1.21
TURBINES AND GENERATORS	60	1.64	1.82	1.74
GOVERNORS AND EXCITATION SYSTEM	50	2.13	2.21	2.13
LICENCE RENEWAL	50	2.00	2.00	2.00
A/C ELECTRICAL POWER SYSTEMS	55	2.07	1.84	1.66
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	4.08	3.90	2.49
AUXILIARY STATION PROCESSES	50	2.62	2.02	2.29
SUPPORT BUILDINGS	65	1.66	1.69	1.60
SUPPORT BUILDING RENOVATIONS	20	5.50	5.67	5.00
COMMUNITY DEVELOPMENT COSTS ***	79	1.16	1.21	1.21
KETTLE				
DAMS, DYKES AND WEIRS	125	0.86	0.86	0.78
POWERHOUSE	125	0.87	0.86	0.79
POWERHOUSE RENOVATIONS	40	4.40	2.75	2.50
SPILLWAY	80	1.33	1.26	1.16
WATER CONTROL SYSTEMS	65	1.55	0.99	0.89
ROADS AND SITE IMPROVEMENTS	50	2.14	2.20	2.31
TURBINES AND GENERATORS	60	1.48	1.90	1.73
GOVERNORS AND EXCITATION SYSTEM	50	1.66	2.14	1.92
LICENCE RENEWAL	50	2.00	2.00	2.00
A/C ELECTRICAL POWER SYSTEMS	55	2.04	2.04	1.96
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	4.11	4.20	3.37
AUXILIARY STATION PROCESSES	50	2.44	1.82	1.86
SUPPORT BUILDINGS	65	1.46	1.75	1.70
SUPPORT BUILDING RENOVATIONS	20	5.50	5.50	5.00

DEPRECIABLE GROUP (Electric Operations)	Expected Service Life	2014-15 Previous ASL Rate %	2014-15 Approved ASL Rate %	2015-16 Approved ELG Rate %
LAURIE RIVER				
DAMS, DYKES AND WEIRS	125	3.47	3.20	2.70
POWERHOUSE	125	4.25	3.89	3.40
POWERHOUSE RENOVATIONS	40	5.00	5.24	4.76
SPILLWAY	80	3.88	3.44	2.96
WATER CONTROL SYSTEMS	65	3.84	3.52	3.03
ROADS AND SITE IMPROVEMENTS	50	4.01	3.69	3.23
TURBINES AND GENERATORS	60	4.49	4.11	3.62
GOVERNORS AND EXCITATION SYSTEM	50	4.70	4.29	3.81
LICENCE RENEWAL	50	4.55	4.76	4.76
A/C ELECTRICAL POWER SYSTEMS	55	4.08	3.63	3.15
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	7.23	6.28	5.15
AUXILIARY STATION PROCESSES	50	4.30	3.73	3.31
SUPPORT BUILDINGS	65	3.75	3.36	2.87
SUPPORT BUILDING RENOVATIONS	20	5.50	5.50	5.00
JENPEG				
DAMS, DYKES AND WEIRS	125	0.92	0.91	0.84
POWERHOUSE	125	0.89	0.90	0.83
POWERHOUSE RENOVATIONS	40	4.40	2.75	2.48
SPILLWAY	80	1.42	1.35	1.28
WATER CONTROL SYSTEMS	65	2.02	1.24	1.07
ROADS AND SITE IMPROVEMENTS	50	2.12	2.07	1.87
TURBINES AND GENERATORS	60	1.63	1.89	1.74
GOVERNORS AND EXCITATION SYSTEM	50	2.20	2.20	2.13
LICENCE RENEWAL	50	2.00	2.00	2.00
A/C ELECTRICAL POWER SYSTEMS	55	2.05	1.81	1.53
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	4.53	4.15	3.39
AUXILIARY STATION PROCESSES	50	2.66	1.92	2.06
SUPPORT BUILDINGS	65	1.67	1.69	1.61
SUPPORT BUILDING RENOVATIONS	20	5.50	5.50	5.00
LAKE WINNIPEG REGULATION				
DAMS, DYKES AND WEIRS	125	0.82	0.82	0.77
LICENCE RENEWAL	50	2.00	2.02	2.02
COMMUNITY DEVELOPMENT COSTS	85	0.94	1.18	1.18
CHURCHILL RIVER DIVERSION				
DAMS, DYKES AND WEIRS	125	0.88	0.88	0.83
SPILLWAY	80	1.47	1.39	1.32
WATER CONTROL SYSTEMS	65	2.21	1.17	1.00
ROADS AND SITE IMPROVEMENTS	50	2.21	2.11	1.78
LICENCE RENEWAL	50	2.00	2.00	2.00
A/C ELECTRICAL POWER SYSTEMS	55	2.21	1.88	1.57
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	4.82	4.78	2.36
AUXILIARY STATION PROCESSES	50	2.75	1.97	2.11
SUPPORT BUILDINGS	65	1.69	1.71	1.66
SUPPORT BUILDING RENOVATIONS	20	5.50	5.50	5.00
COMMUNITY DEVELOPMENT COSTS	90	0.93	1.07	1.07

DEPRECIABLE GROUP (Electric Operations)	Expected Service Life	2014-15 Previous ASL Rate %	2014-15 Approved ASL Rate %	2015-16 Approved ELG Rate %
LONG SPRUCE				
DAMS, DYKES AND WEIRS	125	0.90	0.90	0.83
POWERHOUSE	125	0.90	0.90	0.83
POWERHOUSE RENOVATIONS	40	4.40	2.75	2.50
SPILLWAY	80	1.43	1.36	1.30
WATER CONTROL SYSTEMS	65	2.04	0.99	0.78
ROADS AND SITE IMPROVEMENTS	50	2.10	2.07	1.87
TURBINES AND GENERATORS	60	1.63	1.88	1.69
GOVERNORS AND EXCITATION SYSTEM	50	2.19	2.18	2.08
LICENCE RENEWAL	50	2.00	2.00	2.00
A/C ELECTRICAL POWER SYSTEMS	55	2.09	1.79	1.51
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	4.37	4.37	3.87
AUXILIARY STATION PROCESSES	50	2.63	1.60	1.53
SUPPORT BUILDINGS	65	1.69	1.69	1.64
SUPPORT BUILDING RENOVATIONS	20	5.50	5.50	4.90
LIMESTONE				
DAMS, DYKES AND WEIRS	125	0.90	0.91	0.85
POWERHOUSE	125	0.91	0.91	0.85
POWERHOUSE RENOVATIONS	40	4.40	2.75	2.50
SPILLWAY	80	1.45	1.37	1.37
WATER CONTROL SYSTEMS	65	2.17	1.39	1.28
ROADS AND SITE IMPROVEMENTS	50	2.17	2.14	2.03
TURBINES AND GENERATORS	60	1.68	1.90	1.81
GOVERNORS AND EXCITATION SYSTEM	50	2.17	2.15	1.96
LICENCE RENEWAL	50	2.00	2.00	2.00
A/C ELECTRICAL POWER SYSTEMS	55	2.17	1.89	1.73
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	4.67	4.16	3.48
AUXILIARY STATION PROCESSES	50	2.71	1.78	1.80
SUPPORT BUILDINGS	65	1.68	1.71	1.63
SUPPORT BUILDING RENOVATIONS	20	5.50	5.50	4.89
WUSKWATIM				
DAMS, DYKES AND WEIRS	125	0.88	0.91	0.87
POWERHOUSE	125	0.88	0.91	0.87
POWERHOUSE RENOVATIONS	40	4.40	2.75	2.50
SPILLWAY	80	1.47	1.36	1.46
WATER CONTROL SYSTEMS	65	2.20	1.68	1.62
ROADS AND SITE IMPROVEMENTS	50	2.20	2.19	2.32
TURBINES AND GENERATORS	60	1.69	1.83	1.78
GOVERNORS AND EXCITATION SYSTEM	50	2.20	2.19	2.12
A/C ELECTRICAL POWER SYSTEMS	55	2.20	1.99	1.92
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	4.78	4.24	4.39
AUXILIARY STATION PROCESSES	50	2.75	2.13	2.93
SUPPORT BUILDINGS	65	1.69	1.69	1.64
SUPPORT BUILDING RENOVATIONS	20	5.50	5.50	5.00
INFRASTRUCTURE SUPPORTING GENERATION				
PROVINCIAL ROADS	50	2.30	2.49	2.21
TOWN SITE BUILDING	55	1.71	2.12	2.03
TOWN SITE BUILDINGS RENOVATIONS	20	5.94	5.30	5.00
TOWN SITE OTHER INFRASTRUCTURE	45	2.49	3.11	2.93

DEPRECIABLE GROUP (Electric Operations)	Expected Service Life	2014-15 Previous ASL Rate %	2014-15 Approved ASL Rate %	2015-16 Approved ELG Rate %
THERMAL GENERATION				
BRANDON UNIT 5 (COAL)				
POWERHOUSE	75	3.87	4.52	4.50
POWERHOUSE RENOVATIONS	40	10.00	15.88	15.88
ROADS AND SITE IMPROVEMENTS	50	4.56	5.37	5.36
THERMAL TURBINES AND GENERATORS	60	5.03	5.73	5.72
GOVERNORS AND EXCITATION SYSTEM	50	5.07	5.51	5.52
STEAM GENERATOR AND AUXILIARIES	60	3.93	4.06	4.05
LICENCE RENEWAL	50	10.00	14.81	14.81
A/C ELECTRICAL POWER SYSTEMS	55	4.06	4.65	4.64
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	5.41	4.44	4.41
AUXILIARY STATION PROCESSES	50	4.67	5.36	5.37
SUPPORT BUILDINGS	65	4.25	5.97	5.97
SUPPORT BUILDING RENOVATIONS	20	10.00	16.67	16.67
BRANDON UNITS 6 AND 7				
POWERHOUSE	75	1.65	1.38	1.26
POWERHOUSE RENOVATIONS	40	4.40	2.72	2.46
THERMAL TURBINES AND GENERATORS	60	2.12	1.70	1.64
GOVERNORS AND EXCITATION SYSTEM	50	2.20	2.20	2.13
COMBUSTION TURBINE	25	4.05	3.87	3.66
LICENCE RENEWAL	50	2.00	2.00	2.00
COMBUSTION TURBINE OVERHAULS	15	11.00	7.33	6.67
A/C ELECTRICAL POWER SYSTEMS	55	2.12	1.88	1.78
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	4.58	4.52	4.63
AUXILIARY STATION PROCESSES	50	2.64	1.91	2.10
SELKIRK				
POWERHOUSE	75	0.93	0.76	0.79
POWERHOUSE RENOVATIONS	40	4.00	2.45	2.45
ROADS AND SITE IMPROVEMENTS	50	1.35	1.34	1.42
THERMAL TURBINES AND GENERATORS	60	1.46	1.09	1.18
GOVERNORS AND EXCITATION SYSTEM	50	2.00	1.13	1.30
STEAM GENERATOR AND AUXILIARIES	60	1.34	1.49	1.66
LICENCE RENEWAL	50	2.00	2.00	2.00
A/C ELECTRICAL POWER SYSTEMS	55	1.21	1.06	1.03
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	2.41	2.11	2.40
AUXILIARY STATION PROCESSES	50	1.64	1.19	1.44
SUPPORT BUILDINGS	65	1.06	1.06	1.13
SUPPORT BUILDING RENOVATIONS	20	5.00	5.00	5.00

DEPRECIABLE GROUP (Electric Operations)	Expected Service Life	2014-15 Previous ASL Rate %	2014-15 Approved ASL Rate %	2015-16 Approved ELG Rate %
DIESEL GENERATION				
BUILDINGS	25	2.57	3.15	3.17
BUILDING RENOVATIONS	15	5.14	6.67	6.67
ENGINES AND GENERATORS - OVERHAULS	4	20.00	25.00	25.00
ENGINES AND GENERATORS	22	1.88	2.24	2.73
ACCESSORY STATION EQUIPMENT	20	3.07	3.70	3.67
FUEL STORAGE AND HANDLING	25	2.28	2.37	2.60
TRANSMISSION				
ROADS, TRAILS AND BRIDGES	50	2.51	2.19	2.18
METAL TOWERS AND CONCRETE POLES	85	1.51	1.54	1.23
POLES AND FIXTURES	55	2.49	2.48	1.80
GROUND LINE TREATMENT	10	10.00	10.00	10.00
OVERHEAD CONDUCTOR AND DEVICES	80	1.62	1.27	1.10
UNDERGROUND CABLE AND DEVICES	45	2.23	1.96	1.81
COMMUNITY DEVELOPMENT COSTS ***	79	1.27	1.27	1.27
SUBSTATIONS				
BUILDINGS	65	1.49	1.47	1.46
BUILDING RENOVATIONS	20	5.00	5.00	5.00
ROADS, STEEL STRUCTURES AND CIVIL SITE WORK	50	2.10	1.95	1.76
POLES AND FIXTURES	45	3.25	3.01	2.39
POWER TRANSFORMERS	50	2.21	2.44	2.43
OTHER TRANSFORMERS	50	3.09	2.29	2.26
INTERRUPTING EQUIPMENT	50	2.41	2.52	2.31
OTHER STATION EQUIPMENT	45	2.54	2.47	2.20
ELECTRONIC EQUIPMENT AND BATTERIES	25	4.76	3.81	3.90
SYNCHRONOUS CONDENSERS AND UNIT TRANSFORMERS	65	1.68	1.80	1.52
SYNCHRONOUS CONDENSER OVERHAULS	15	7.43	7.15	5.58
HVDC CONVERTER EQUIPMENT	30	4.13	3.22	2.61
HVDC SERIALIZED EQUIPMENT	30	4.18	3.04	2.07
HVDC ACCESSORY STATION EQUIPMENT	36	2.85	2.98	2.67
HVDC ELECTRONIC EQUIPMENT AND BATTERIES	25	4.66	3.10	2.27
DISTRIBUTION				
CONCRETE DUCTLINE AND MANHOLES	75	2.29	2.23	2.25
CONCRETE DUCTLINE AND MANHOLE REFURBISHMENTS	30	2.08	3.66	3.70
METAL TOWERS	60	1.99	2.10	1.87
POLES AND FIXTURES	65	2.10	1.96	1.58
GROUND LINE TREATMENT	12	9.58	7.39	7.39
OVERHEAD CONDUCTOR AND DEVICES	60	1.98	2.24	1.80
UNDERGROUND CABLE AND DEVICES - 66 KV	60	1.48	1.72	2.07
UNDERGROUND CABLE AND DEVICES - PRIMARY	60	1.69	1.70	1.83
UNDERGROUND CABLE AND DEVICES - SECONDARY	44	2.21	2.27	2.31
SERIALIZED EQUIPMENT - OVERHEAD	45	2.86	2.28	2.10
DSC - HIGH VOLTAGE TRANSFORMERS	50	2.19	2.34	2.34
SERIALIZED EQUIPMENT - UNDERGROUND	42	2.62	2.60	2.40
ELECTRONIC EQUIPMENT	10	10.00	10.53	10.53
SERVICES	35	4.38	2.92	1.89
STREET LIGHTING	45	3.04	2.56	2.20

DEPRECIABLE GROUP (Electric Operations)	Expected Service Life	2014-15 Previous ASL Rate %	2014-15 Approved ASL Rate %	2015-16 Approved ELG Rate %
METERS				
METERS - ELECTRONIC	15	6.10	9.61	10.52
METERS - ANALOG	26	13.54	3.84	4.21
METERING EXCHANGES	15	6.67	6.67	6.67
METERING TRANSFORMERS	50	2.20	1.80	2.12
COMMUNICATION				
BUILDINGS	65	1.67	1.41	1.48
BUILDING RENOVATIONS	20	5.67	4.95	4.58
BUILDING - SYSTEM CONTROL CENTRE	75	1.68	1.39	1.40
COMMUNICATION TOWERS	60	1.82	1.82	2.01
FIBRE OPTIC AND METALLIC CABLE	35	3.06	3.12	3.45
CARRIER EQUIPMENT	20	7.68	4.74	4.90
OPERATIONAL IT EQUIPMENT	5	22.97	21.00	20.00
MOBILE RADIO, TELEPHONE AND VIDEO CONFERENCING	8	10.24	18.56	16.64
OPERATIONAL DATA NETWORK	8	14.10	13.13	12.50
POWER SYSTEM CONTROL	15	11.16	5.63	5.50
MOTOR VEHICLES				
PASSENGER VEHICLES	11	11.09	7.03	7.59
LIGHT TRUCKS	12	7.85	7.16	7.54
HEAVY TRUCKS	19	5.83	4.68	5.01
CONSTRUCTION EQUIPMENT	23	5.27	2.77	3.23
LARGE SOFT-TRACK EQUIPMENT	27	4.28	2.96	3.79
TRAILERS	35	1.94	2.38	2.91
MISCELLANEOUS VEHICLES	13	5.93	4.90	6.60
BUILDINGS				
BUILDINGS - GENERAL	65	1.59	1.65	1.73
BUILDING RENOVATIONS	20	7.14	5.59	5.00
BUILDING - 360 PORTAGE - CIVIL	100	1.00	1.00	1.06
BUILDING - 360 PORTAGE - ELECTRO/MECHANICAL	45	2.21	2.23	2.56
LEASEHOLD IMPROVEMENTS - SONY PLACE	10	10.00	10.00	10.00
GENERAL EQUIPMENT				
TOOLS, SHOP AND GARAGE EQUIPMENT	15	7.74	6.48	6.48
COMPUTER EQUIPMENT	5	28.48	20.00	20.00
OFFICE FURNITURE AND EQUIPMENT	20	4.81	5.00	5.00
HOT WATER TANKS	6	21.20	16.67	16.67
EASEMENTS				
EASEMENTS	75	1.28	1.33	1.33
COMPUTER SOFTWARE AND DEVELOPMENT				
COMPUTER DEVELOPMENT - MAJOR SYSTEMS	11	9.47	8.75	8.82
COMPUTER DEVELOPMENT - SMALL SYSTEMS	10	10.00	9.13	9.13
COMPUTER SOFTWARE - GENERAL	5	19.76	20.00	20.00
COMPUTER SOFTWARE - COMMUNICATION/OPERATIONAL	5	13.93	27.31	27.31
OPERATIONAL SYSTEM MAJOR SOFTWARE - EMS/SCADA	7	23.35	8.06	9.33

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Section:	Appendix 5.6	Page No.:	
Topic:	Depreciation		
Subtopic:	Comparison to 2010 Depreciation Study		
Issue:	Overview of Depreciation Method changes		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please update MIPUG/MH I-15(p) from the 2012/14 GRA providing revised depreciation expense for actual and forecasts through 2016/17. For each year, separately identify the impacts of addition of assets, including Wuskwatim, the impacts of adoption of ELG, new depreciation study lives, and the impact of the elimination of asset retirement costs.

RATIONALE FOR QUESTION:

To review the 2014 Depreciation Study the implications on rate payers and how those implications have changed since the 2012/13 & 2013/14 GRA.

RESPONSE:

The following schedule identifies the incremental impact on annual depreciation expense of the following items:

- Net asset additions (additions net of retirements);
- Wuskwatim;
- 2010 Depreciation Study changes, including changes to componentization and to average service lives;
- 2014 Depreciation Study changes to average service lives;
- Implementation of IFRS, including the change to an IFRS compliant depreciation method (ELG), removal of the provision for net salvage from depreciation rates, removal of IFRS ineligible costs from capitalized overhead and capitalization of meter exchange program costs.

MANITOBA HYDRO - CONSOLIDATED ELECTRIC OPERATIONS
DEPRECIATION AND AMORTIZATION EXPENSE

	2007/08 Actual	Net Additions	2008/09 Actual	Net Additions	2009/10 Actual	Net Additions	2010/11 Actual
Generation							
Hydraulic Generating Stations	68,451	2,460	70,911	3,399	74,310	1,818	76,128
Thermal Generating Stations	17,170	106	17,276	336	17,612	(7,842)	9,771
Amortization of Planning Studies	2,366	(2,366)	-	-	-	-	
Demand Side Management	11,357	7,800	19,157	2,907	22,064	1,930	23,994
Diesel Generating Stations	4,067	(134)	3,933	(381)	3,552	139	3,691
Amortization of Contributions	(2,774)	(22)	(2,796)	-	(2,796)	-	(2,796)
	$ 100,637	$ 7,844	$ 108,481	$ 6,262	$ 114,743	$ (3,955)	$ 110,788
Transmission							
Transmission	14,120	197	14,317	11	14,328	143	14,471
Amortization of Contributions	(1,631)	(6)	(1,638)	-	(1,638)	9	(1,629)
	$ 12,489	$ 191	$ 12,680	$ 11	$ 12,690	$ 152	$ 12,842
Stations							
Substations	70,616	1,896	72,512	1,611	74,123	2,624	76,747
Transformers	3,681	(1,393)	2,288	(167)	2,121	(468)	1,653
Amortization of Contributions	(1,461)	(1)	(1,462)	(2)	(1,464)	(6)	(1,470)
	$ 72,836	$ 502	$ 73,338	$ 1,442	$ 74,780	$ 2,150	$ 76,930
Distribution							
Subtransmission Lines	8,905	261	9,166	303	9,469	423	9,892
Distribution Lines	72,410	5,320	77,730	4,949	82,679	4,515	87,194
Meters & Metering Transformers	1,551	46	1,597	(7)	1,590	25	1,615
Amortization of Contributions	(9,769)	(411)	(10,180)	(263)	(10,443)	(267)	(10,710)
	$ 73,097	$ 5,215	$ 78,312	$ 4,983	$ 83,295	$ 4,696	$ 87,991
Other							
Communications	17,636	1,837	19,473	1,474	20,947	1,571	22,518
Motor Vehicles	8,275	416	8,691	69	8,760	740	9,500
Structures & Improvements	3,216	2,476	5,692	898	6,590	832	7,422
General Equipment	20,572	(2,898)	17,674	332	18,006	(834)	17,172
Computer Development	13,582	499	14,081	373	14,454	799	15,253
Affordable Energy Fund	625	816	1,441	1,617	3,058	410	3,468
Miscellaneous	2,701	(238)	2,463	532	2,995	(372)	2,623
Corporate Allocation	(2,093)	81	(2,012)	(127)	(2,139)	359	(1,780)
	$ 64,514	$ 2,989	$ 67,503	$ 5,168	$ 72,671	$ 3,505	$ 76,176
Total Dep'n and Amort Expense	$ 323,573	$ 16,741	$ 340,314	$ 17,865	$ 358,179	$ 6,547	$ 364,727

MANITOBA HYDRO - CONSOLIDATED ELECTRIC OPERATIONS
DEPRECIATION AND AMORTIZATION EXPENSE

	2010/11 Actual	Year over Year Change: Net Additions	Year over Year Change: 2010 Depn Study Component Reclass	Year over Year Change: 2010 Depn Study Change in Asset Life	2011/12 Actual
Generation					
Hydraulic Generating Stations	76,128	3,692	(352)	(4,404)	75,064
Thermal Generating Stations	9,771	1,180	(426)	(1,845)	8,680
Demand Side Management	23,994	2,197	-	-	26,191
Diesel Generating Stations	3,691	1,685	-	(4,017)	1,359
Amortization of Contributions	(2,796)	(246)	-	2,325	(718)
	$ 110,788	$ 8,508	$ (778)	$ (7,941)	$ 110,576
Transmission					
Transmission	14,471	74	-	(625)	13,920
Amortization of Contributions	(1,629)	1	-	271	(1,357)
	$ 12,842	$ 75	$ -	$ (354)	$ 12,563
Stations					
Substations	76,747	5,060	1,909	(4,558)	79,157
Transformers	1,653	316	-	(278)	1,691
Amortization of Contributions	(1,470)	(29)	-	251	(1,247)
	$ 76,930	$ 5,347	$ 1,909	$ (4,585)	$ 79,601
Distribution					
Subtransmission Lines	9,892	714	-	(4,632)	5,974
Distribution Lines	87,194	4,999	-	(36,646)	55,547
Meters & Metering Transformers	1,615	(176)	-	2,766	4,205
Amortization of Contributions	(10,710)	(401)	-	6,337	(4,774)
	$ 87,991	$ 5,136	$ -	$ (32,175)	$ 60,952
Other					
Communications	22,518	(7,768)	-	5,368	20,118
Motor Vehicles	9,500	1,736	-	(862)	10,374
Structures & Improvements	7,422	403	(1,131)	924	7,618
General Equipment	17,172	826	-	5,495	23,493
Computer Development	15,253	3,485	-	157	18,895
Affordable Energy Fund	3,468	4,004	-	-	7,472
Miscellaneous	2,623	797	-	-	3,420
Corporate Allocation	(1,780)	-	-	74	(1,706)
	$ 76,176	$ 3,482	$ (1,131)	$ 11,156	$ 89,684
Total Dep'n and Amort Expense	$ 364,727	$ 22,548	$ -	$ (33,899)	$ 353,376

MANITOBA HYDRO - CONSOLIDATED ELECTRIC OPERATIONS
DEPRECIATION AND AMORTIZATION EXPENSE

	2011/12 Actual	Year over Year Change: Net Additions	Year over Year Change: Wuskwatim	Year over Year Change: 2010 Depn Study Change in Asset Life	2012/13 Actual *
Generation					
Hydraulic Generating Stations	75,064	5,375	12,115	(329)	92,225
Thermal Generating Stations	8,680	6,582	-	153	15,415
Demand Side Management	26,191	2,026	-	-	28,217
Diesel Generating Stations	1,359	7	-	91	1,457
Amortization of Contributions	(718)	(523)	-	399	(841)
	$ 110,576	$ 13,468	$ 12,115	$ 314	$ 136,473
Transmission					
Transmission	13,920	855	1,362	(204)	15,933
Amortization of Contributions	(1,357)	(1)	-	-	(1,358)
	$ 12,562	$ 854	$ 1,362	$ (204)	$ 14,575
Stations					
Substations	79,157	4,002	2,409	(666)	84,902
Transformers	1,691	115	-	(1)	1,806
Amortization of Contributions	(1,247)	(2)	-	2	(1,247)
	$ 79,601	$ 4,115	$ 2,409	$ (664)	$ 85,461
Distribution					
Subtransmission Lines	5,974	562	-	(265)	6,271
Distribution Lines	55,547	4,205	14	(1,582)	58,184
Meters & Metering Transformers	4,205	50	-	17	4,273
Amortization of Contributions	(4,774)	(698)	-	388	(5,084)
	$ 60,952	$ 4,120	$ 14	$ (1,442)	$ 63,644
Other			-		-
Communications	20,118	(485)	258	(441)	19,450
Motor Vehicles	10,374	626	17	(45)	10,971
Structures & Improvements	7,618	146	-	183	7,947
General Equipment	23,493	1,731	4	582	25,810
Computer Development	18,895	1,608	-	79	20,582
Affordable Energy Fund	7,472	(2,066)	-	-	5,406
Miscellaneous	3,420	131	-	(1)	3,550
Corporate Allocation	(1,706)	(241)	-	1	(1,946)
	$ 89,683	$ 1,449	$ 279	$ 358	$ 91,770
Total Dep'n and Amort Expense	$ 353,375	$ 24,004	$ 16,179	$ (1,638)	$ 391,923

* 2012/13 Actual figures have been restated from those shown in Schedule 5.1.6 to reflect the reallocation of Wuskwatim costs into the respective asset reporting categories.

MANITOBA HYDRO - CONSOLIDATED ELECTRIC OPERATIONS
DEPRECIATION AND AMORTIZATION EXPENSE

	2012/13 Actual *	Year over Year Change: Net Additions	Wuskwatim	2010 Depn Study: Change in Asset Life	2013/14 Actual *
Generation					
Hydraulic Generating Stations	92,225	3,504	7,940	(1,562)	102,108
Thermal Generating Stations	15,415	213	-	(66)	15,562
Demand Side Management	28,217	2,045	-	-	30,262
Diesel Generating Stations	1,457	(536)	-	836	1,757
Amortization of Contributions	(841)	(114)	-	87	(868)
	$ 136,473	$ 5,112	$ 7,940	$ (705)	$ 148,821
Transmission					
Transmission	15,933	547	994	(400)	17,074
Amortization of Contributions	(1,358)	(497)	-	370	(1,485)
	$ 14,575	$ 50	$ 994	$ (31)	$ 15,588
Stations					
Substations	84,902	3,724	2,383	(3,799)	87,210
Transformers	1,806	128	-	6	1,940
Amortization of Contributions	(1,247)	90	-	254	(903)
	$ 85,461	$ 3,941	$ 2,383	$ (3,539)	$ 88,247
Distribution					
Subtransmission Lines	6,271	667	-	(309)	6,629
Distribution Lines	58,184	5,060	25	(1,927)	61,342
Meters & Metering Transformers	4,273	20	-	(33)	4,260
Amortization of Contributions	(5,084)	(868)	-	496	(5,456)
	$ 63,644	$ 4,879	$ 25	$ (1,774)	$ 66,774
Other	-				
Communications	19,450	269	165	1,846	21,730
Motor Vehicles	10,971	702	(2)	(83)	11,588
Structures & Improvements	7,947	(76)	-	195	8,066
General Equipment	25,810	(1,449)	3	(1,102)	23,261
Computer Development	20,582	(423)	-	(492)	19,667
Affordable Energy Fund	5,406	(996)	-	-	4,410
Miscellaneous	3,550	1,041	-	37	4,628
Corporate Allocation	(1,946)	-	-	-	(1,946)
	$ 91,770	$ (931)	$ 165	$ 401	$ 91,404
Total Dep'n and Amort Expense	$ 391,923	$ 13,052	$ 11,508	$ (5,648)	$ 410,834

* 2012/13 and 2013/14 Actual figures have been restated from those shown in Schedule 5.1.6 to reflect the reallocation of Wuskwatim costs into the respective asset reporting categories.

MANITOBA HYDRO - CONSOLIDATED ELECTRIC OPERATIONS
DEPRECIATION AND AMORTIZATION EXPENSE

	2013/14 Actual *	Year over Year Change (Forecast) Net Additions	2010 Depn Study Change in Asset Life	2014 Depn Study Change in Asset Life	2014/15 Forecast *
Generation					
Hydraulic Generating Stations	102,108	6,350	484	4,047	112,990
Thermal Generating Stations	15,562	106	(18)	121	15,770
Demand Side Management	30,262	1,314	-	-	31,576
Diesel Generating Stations	1,757	629	(494)	451	2,342
Amortization of Contributions	(868)	(278)	212	(115)	(1,049)
	$ 148,821	$ 8,121	$ 184	$ 4,503	$ 161,629
Transmission					
Transmission	17,074	234	192	(1,170)	16,329
Amortization of Contributions	(1,485)	(12)	33	74	(1,391)
	$ 15,588	$ 222	$ 225	$ (1,097)	$ 14,938
Stations					
Substations	87,210	12,304	(1,007)	(9,953)	88,555
Transformers	1,940	100	17	(430)	1,627
Amortization of Contributions	(903)	(513)	220	27	(1,170)
	$ 88,247	$ 11,891	$ (770)	$ (10,356)	$ 89,012
Distribution					
Subtransmission Lines	6,629	3,255	(2,637)	129	7,376
Distribution Lines	61,342	5,300	(2,223)	(3,905)	60,514
Meters & Metering Transformers	4,260	4	(65)	(1,351)	2,848
Amortization of Contributions	(5,456)	(1,727)	871	635	(5,678)
	$ 66,774	$ 6,832	$ (4,055)	$ (4,491)	$ 65,061
Other	-				
Communications	21,730	(168)	(286)	(4,108)	17,167
Motor Vehicles	11,588	702	(52)	(2,076)	10,162
Structures & Improvements	8,066	244	165	(547)	7,928
General Equipment	23,261	(1,229)	(857)	(4,545)	16,631
Computer Development	19,667	53	204	(2,237)	17,687
Affordable Energy Fund	4,410	860	-	-	5,270
Miscellaneous	4,628	(2,987)	(1)	62	1,701
Corporate Allocation	(1,946)	0	1	(30)	(1,974)
Target Adjustment	-	(619)	-	(1)	(621)
	$ 91,404	$ (3,145)	$ (826)	$ (13,482)	$ 73,951
Total Dep'n and Amort Expense	$ 410,834	$ 23,921	$ (5,243)	$ (24,923)	$ 404,590

* 2013/14 Actual and 2014/15 Forecast figures have been restated from those shown in Schedule 5.1.6 to reflect the reallocation of Wuskwatim costs into the respective asset reporting categories.

MANITOBA HYDRO - CONSOLIDATED ELECTRIC OPERATIONS
DEPRECIATION AND AMORTIZATION EXPENSE

	2014/15 Forecast *	Year over Year Change (Forecast) Net Additions	2010 Depn Study Change in Asset Life	2014 Depreciation Study Change in Asset Life	2014 Depreciation Study ELG	2014 Depreciation Study Removal of Net Salvage	IFRS Remove Indirect Overhead	Capitalize Meter Exchange Program	2015/16 Forecast *
Generation									
Hydraulic Generating Stations	112,990	7,237	415	(3,749)	9,282	(13,690)	-	-	112,484
Thermal Generating Stations	15,770	85	9	5	1,618	(1,731)	-	-	15,755
Demand Side Management	31,576	3,381	-	-	-	-	-	-	34,957
Diesel Generating Stations	2,342	586	(500)	13	237	(121)	-	-	2,557
Amortization of Contributions	(1,049)	(399)	302	-	-	-	-	-	(1,146)
	$ 161,629	$ 10,890	$ 225	$ (3,730)	$ 11,136	$ (15,542)	$ -	$ -	$ 164,608
Transmission									
Transmission	16,329	614	(13)	(2)	1,030	(4,244)	-	-	13,714
Amortization of Contributions	(1,391)	(228)	1	-	-	-	-	-	(1,618)
	$ 14,938	$ 386	$ (12)	$ (2)	$ 1,030	$ (4,244)	$ -	$ -	$ 12,095
Stations									
Substations	88,555	12,264	(767)	(3,322)	9,058	(18,922)	-	-	86,865
Transformers	1,627	(2,085)	49	2,426	82	(502)	-	-	1,597
Amortization of Contributions	(1,170)	185	-	-	-	-	-	-	(985)
	$ 89,012	$ 10,364	$ (718)	$ (896)	$ 9,140	$ (19,425)	$ -	$ -	$ 87,477
Distribution									
Subtransmission Lines	7,376	1,300	(473)	(61)	1,558	(2,753)	-	-	6,948
Distribution Lines	60,514	6,418	(2,737)	98	9,394	(16,693)	-	-	56,995
Meters & Metering Transformers	2,848	(23)	(21)	112	329	6	-	31	3,281
Amortization of Contributions	(5,678)	(1,663)	925	43	-	(13)	-	-	(6,386)
	$ 65,061	$ 6,032	$ (2,306)	$ 192	$ 11,281	$ (19,452)	$ -	$ 31	$ 60,838
Other									
Communications	17,167	553	251	(314)	1,688	(1,186)	-	-	18,160
Motor Vehicles	10,162	759	(75)	(76)	1,092	(31)	-	-	11,830
Structures & Improvements	7,928	543	130	(87)	688	(402)	-	-	8,800
General Equipment	16,631	(739)	(495)	1,387	-	1	-	-	16,784
Computer Development	17,687	785	(62)	(163)	239	1	-	-	18,487
Affordable Energy Fund	5,270	(980)	-	-	-	-	-	-	4,290
Miscellaneous	1,701	1,029	(11)	124	266	(458)	-	-	2,652
Corporate Allocation	(1,974)	(6)	(6)	(55)	(266)	458	-	-	(1,850)
Target Adjustment	(621)	(2,498)	-	(8)	(274)	515	(419)	-	(3,305)
	$ 73,951	$ (554)	$ (268)	$ 808	$ 3,432	$ (1,103)	$ (419)	$ -	$ 75,848
Total Dep'n and Amort Expense	$ 404,590	$ 27,118	$ (3,080)	$ (3,628)	$ 36,019	$ (59,765)	$ (419)	$ 31	$ 400,866

* 2014/15 and 2015/16 Forecast figures have been restated from those shown in Schedule 5.1.6 to reflect the reallocation of Wuskwatim costs into the respective asset reporting categories.

MANITOBA HYDRO - CONSOLIDATED ELECTRIC OPERATIONS
DEPRECIATION AND AMORTIZATION EXPENSE

	2015/16 Forecast *	Year over Year Change (Forecast): Net Additions	2010 Depn Study: Change in Asset Life	2014 Depreciation Study: Change in Asset Life	2014 Depreciation Study: ELG	2014 Depreciation Study: Removal of Net Salvage	IFRS Remove Indirect Overhead	Capitalize Meter Exchange Program	2016/17 Forecast *
Generation									
Hydraulic Generating Stations	112,484	4,532	145	120	830	(1,769)	-	-	116,342
Thermal Generating Stations	15,755	69	23	6	43	(41)	-	-	15,856
Demand Side Management	34,957	2,544	-	-	-	-	-	-	37,501
Diesel Generating Stations	2,557	(128)	(73)	(245)	-	-	-	-	2,111
Amortization of Contributions	(1,146)	-	-	-	-	-	-	-	(1,146)
	$ 164,608	$ 7,017	$ 96	$ (120)	$ 873	$ (1,810)	$ -	$ -	$ 170,664
Transmission									
Transmission	13,714	1,385	(56)	(48)	86	(369)	-	-	14,712
Amortization of Contributions	(1,618)	(3)	(2)	-	-	-	-	-	(1,623)
	$ 12,095	$ 1,382	$ (58)	$ (48)	$ 86	$ (369)	$ -	$ -	$ 13,089
Stations									
Substations	86,865	5,882	(429)	(720)	565	(849)	-	-	91,313
Transformers	1,597	(30)	44	337	(23)	(97)	-	-	1,828
Amortization of Contributions	(985)	-	-	-	-	-	-	-	(985)
	$ 87,477	$ 5,852	$ (386)	$ (383)	$ 543	$ (946)	$ -	$ -	$ 92,156
Distribution									
Subtransmission Lines	6,948	797	(289)	(29)	80	(106)	-	-	7,401
Distribution Lines	56,995	7,501	(2,789)	(487)	645	(907)	-	-	60,959
Meters & Metering Transformers	3,281	(35)	68	(53)	12	16	-	114	3,404
Amortization of Contributions	(6,386)	(1,520)	875	53	-	(7)	-	-	(6,985)
	$ 60,838	$ 6,743	$ (2,135)	$ (515)	$ 737	$ (1,004)	$ -	$ 114	$ 64,778
Other									
Communications	18,160	697	268	(740)	81	139	-	-	18,604
Motor Vehicles	11,830	417	(41)	34	47	(51)	-	-	12,236
Structures & Improvements	8,800	700	144	(103)	59	(44)	-	-	9,557
General Equipment	16,784	(650)	(355)	1,026	-	-	-	-	16,804
Computer Development	18,487	2,814	82	(604)	37	-	-	-	20,816
Conawapa	-	7,711	-	-	-	-	-	-	7,711
Affordable Energy Fund	4,290	(2,781)	-	-	-	-	-	-	1,509
Miscellaneous	2,652	642	21	(47)	-	2	-	-	3,269
Corporate Allocation	(1,850)	0	(28)	27	-	(2)	-	-	(1,853)
Target Adjustment	(3,305)	(1,750)	-	(58)	(340)	615	(2,100)	-	(6,938)
	$ 75,848	$ 7,800	$ 90	$ (464)	$ (114)	$ 658	$ (2,100)	$ -	$ 81,717
Total Dep'n and Amort Expense	$ 400,866	$ 28,794	$ (2,393)	$ (1,530)	$ 2,125	$ (3,471)	$ (2,100)	$ 114	$ 422,404

* 2015/16 and 2016/17 Forecast figures have been restated from those shown in Schedule 5.1.6 to reflect the reallocation of Wuskwatim costs into the respective asset reporting categories.

Section:	Appendix 5.6	Page No.:	
Topic:	Depreciation		
Subtopic:	Comparison to 2010 Depreciation Study		
Issue:	Overview of Depreciation Method changes		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please compare the forecast 2012/13 and 2013/14 from MIPUG/MH I-15(p) to actual depreciation expense for 2012/13 and 2013/14 including rationale for changes between forecast and actual.

RATIONALE FOR QUESTION:

To review the 2014 Depreciation Study the implications on rate payers and how those implications have changed since the 2012/13 & 2013/14 GRA.

RESPONSE:

The following schedule provides a comparison of the 2012/13 and 2013/14 forecast depreciation expense from MIPUG/MH I-15p, from the 2012/13 & 2013/14 GRA, with actual depreciation expense for the same years.

Differences between Forecast and Actual depreciation expense are discussed below:

- Net Additions: The overall variance attributable to differences in the balance of plant in service is less than -0.4% in both 2012/13 and 2013/14 as compared to forecast. Differences within each category are primarily due to the forecast target adjustment. Please refer to PUB/MH I-25b for an explanation of significant differences between forecast and actual in-service amounts for large capital projects.

- Wuskwatim: The reduction in depreciation expense for Wuskwatim is due primarily to a delay in final in-service from June 2012 to October 2012.

- 2010 Depreciation Study – Change in Asset Life: The variance is due to differences between forecasted and actual net plant additions and retirements as well as the ongoing refinement of componentization estimates.

- Deferral of IFRS Implementation: The forecast assumed the implementation of IFRS in 2013/14 which has been deferred to the 2015/16. The following provides a summary of the impacts of the deferral:

Forecast IFRS Implementation Changes ($000's)	**Impact**
Implementation of IFRS compliant methodology (ELG)	$ (32,307)
Removal of net salvage provision from depreciation rates	55,574
Removal of IFRS ineligible indirect overhead from capital cost	221
Removal of depreciation of rate regulated assets	36,792
	$ 60,280

MANITOBA HYDRO - CONSOLIDATED ELECTRIC OPERATIONS
DEPRECIATION AND AMORTIZATION EXPENSE

	2012/13 Forecast *	Difference - Actual vs Forecast: Net Additions	Wuskwatim	2010 Depn Study Change in Asset Life	2012/13 Actual **	2013/14 Forecast *	Cummulative Difference - Actual vs Forecast: Net Additions	Wuskwatim	2010 Depn Study Change in Asset Life	Deferral of IFRS Implementation	2013/14 Actual **
Generation											
Hydraulic Generating Stations	97,254	1,617	(7,878)	1,232	92,225	97,852	1,157	(2,382)	85	5,396	102,108
Thermal Generating Stations	16,036	(814)	-	193	15,415	16,496	(1,043)	-	179	(71)	15,562
Demand Side Management	28,664	(447)	-	-	28,217	-	(1,133)	-	-	31,395	30,262
Diesel Generating Stations	1,407	180	-	(130)	1,457	1,368	(552)	-	860	82	1,757
Amortization of Contributions	(1,033)	80	-	112	(841)	(1,092)	101	-	123	-	(868)
	$ 142,328	$ 615	$ (7,878)	$ 1,408	$ 136,473	$ 114,624	$ (1,470)	$ (2,382)	$ 1,246	$ 36,802	$ 148,821
Transmission										-	
Transmission	16,995	(74)	(899)	(89)	15,933	14,179	(68)	95	(464)	3,332	17,074
Amortization of Contributions	(1,358)	(87)	-	87	(1,358)	(1,360)	(563)	-	437	-	(1,485)
	$ 15,636	$ (161)	$ (899)	$ (2)	$ 14,575	$ 12,819	$ (631)	$ 95	$ (27)	$ 3,332	$ 15,588
Stations											
Substations	87,181	(1,204)	(851)	(223)	84,902	80,893	(933)	1,532	(3,827)	9,545	87,210
Transformers	1,983	(196)	-	18	1,806	2,200	(606)	-	54	291	1,940
Amortization of Contributions	(1,235)	(107)	-	95	(1,247)	(1,235)	(2)	-	334	-	(903)
	$ 87,929	$ (1,507)	$ (851)	$ (109)	$ 85,461	$ 81,858	$ (1,540)	$ 1,532	$ (3,439)	$ 9,837	$ 88,247
Distribution											
Subtransmission Lines	6,215	9	-	47	6,271	5,423	120	-	(38)	1,124	6,629
Distribution Lines	59,820	(2,425)	(24)	813	58,184	52,309	(2,859)	1	1,100	10,790	61,342
Meters & Metering Transformers	5,019	(792)	-	46	4,273	5,603	(758)	-	39	(624)	4,260
Amortization of Contributions	(5,318)	115	-	120	(5,084)	(5,551)	(202)	-	298	-	(5,456)
	$ 65,736	$ (3,093)	$ (24)	$ 1,025	$ 63,644	$ 57,784	$ (3,700)	$ 1	$ 1,398	$ 11,291	$ 66,774
Other											
Communications	25,153	(4,876)	226	(1,053)	19,450	29,634	(5,938)	391	337	(2,694)	21,730
Motor Vehicles	9,935	1,012	17	7	10,971	12,010	1,372	15	(49)	(1,760)	11,588
Structures & Improvements	8,509	(572)	-	10	7,947	9,495	(1,008)	-	99	(520)	8,066
General Equipment	23,011	2,373	4	421	25,810	21,226	2,286	6	(257)	-	23,261
Computer Development	16,376	4,081	-	125	20,582	18,937	2,064	-	(315)	(1,019)	19,667
Affordable Energy Fund	8,870	(3,464)	-	-	5,406	8,710	(4,300)	-	-	-	4,410
Miscellaneous	3,759	(207)	-	(1)	3,550	(3,418)	2,678	-	36	5,333	4,628
Corporate Allocation	(1,707)	(240)	-	1	(1,946)	(1,208)	(739)	-	1	-	(1,946)
Target Adjustment	(4,691)	5,163	-	(472)	-	(8,163)	9,571	-	(1,086)	(322)	-
	$ 89,216	$ 3,270	$ 247	$ (964)	$ 91,770	$ 87,223	$ 5,987	$ 412	$ (1,235)	$ (982)	$ 91,404
Total Dep'n and Amort Expense	$ 400,845	$ (876)	$ (9,405)	$ 1,358	$ 391,923	$ 354,307	$ (1,354)	$ (342)	$ (2,057)	$ 60,280	$ 410,834

* Forecast figures shown are as reported for the 2012/13 & 2013/14 GRA in the response to MIPUG/MH I-15p (MH11-2).
** 2012/13 AND 2013/14 Actual figures have been restated from those shown in Schedule 5.1.6 to reflect the reallocation of Wuskwatim costs into the respective asset reporting categories.

Section:	Tab 5 Tab 5: Appendix 5.6 Tab 11 Tab 11: Appendix 11.43	**Page No.:**	26 2 & 7 14 2
Topic:	Financial Results & Forecasts		
Subtopic:	Depreciation and Amortization		
Issue:	Changes in the Calculation of Depreciation		

PREAMBLE TO IR (IF ANY):

QUESTION:

Manitoba Hydro is planning (Tab 5, page 26) on eliminating the provision in depreciation rates for asset removal costs upon its transition to IRFS. How will asset removal costs be recovered upon elimination of the provision and where/how does this impact IFF14?

RATIONALE FOR QUESTION:

Clarify the impacts of the proposed changes in the calculation of depreciation expense.

RESPONSE:

Upon the adoption of IFRS by Manitoba Hydro, asset removal costs will be recovered by either the recognition of an asset retirement obligation or by adding the removal costs of the retired asset to the cost of the replacement asset.

- Asset retirement obligations will be recognized where Manitoba Hydro has a future obligation to terminally retire a significant plant asset and the costs associated with retiring that asset are material and can be reasonably estimated. In the year that the decision is made to retire the asset, Manitoba Hydro will record the present value of the future costs to retire the asset as an additional cost of the asset to be retired. These costs will be amortized over the remaining service life of the asset. In addition, as the present value cost of the obligation increases each year towards the asset's retirement date, an annual accretion charge will be made to finance expense.

As of March 31, 2014, Manitoba Hydro has asset retirement costs established for the future decommissioning of the Brandon Thermal Generating Station and for the partial decommissioning of the Pointe du Bois Generating Station spillway.

- In circumstances where the plant asset to be retired is to be replaced by a similar plant asset, the costs of removing the retired asset will be added to the cost of the replacement asset and amortized over the service life of the asset.

IFF14 assumes no new asset retirement obligations and that asset removal costs are added to the cost of the replacement asset and amortized over the service life of the asset. In addition, IFF14 assumes an adjustment to retained earnings of $57 million for retrospective application of the negative salvage costs for fiscal 2014/15.

Section:	Tab 5 Tab 5: Appendix 5.6 Tab 11 Tab 11: Appendix 11.43	Page No.:	26 2 & 7 14 2
Topic:	Financial Results & Forecasts		
Subtopic:	Depreciation and Amortization		
Issue:	Changes in the Calculation of Depreciation		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please confirm that the $2 M reduction in depreciation shown for 2016/17 and attributed to Overhead Ineligible for Capitalization (per Appendix 5.6, page 2) reflects the lower capital costs for facilities coming into service in 2016/17 due to the adoption of IFRS in 2015/16 and the corresponding reduction in capitalized OM&A costs for these projects.

RATIONALE FOR QUESTION:

Clarify the impacts of the proposed changes in the calculation of depreciation expense.

RESPONSE:

Confirmed. The $2 million reduction in depreciation expense for the 2016/17 forecast year is attributed to lower capital costs for facilities coming into service as a result of expensing overhead costs ineligible for capitalization in both the 2015/16 and 2016/17 forecast years. Such costs are being expensed as a result of the adoption of IFRS in fiscal 2015/16.

Section:	Tab 5 Tab 5: Appendix 5.6 Tab 11 Tab 11: Appendix 11.43	**Page No.:**	26 2 & 7 14 2
Topic:	Financial Results & Forecasts		
Subtopic:	Depreciation and Amortization		
Issue:	Changes in the Calculation of Depreciation		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please clarify whether the 2015 Approved ASL Rates in Appendix 5.6, page 7 are viewed as IFRS compliant – per Tab 11, page 14. If not, why not?

RATIONALE FOR QUESTION:

Clarify the impacts of the proposed changes in the calculation of depreciation expense.

RESPONSE:

Please see the response to PUB MH-I-39c.

Section:	Tab 5 Tab 5: Appendix 5.6 Tab 11 Tab 11: Appendix 11.43	Page No.:	26 2 & 7 14 2
Topic:	Financial Results & Forecasts		
Subtopic:	Depreciation and Amortization		
Issue:	Changes in the Calculation of Depreciation		

PREAMBLE TO IR (IF ANY):

QUESTION:

Has Manitoba Hydro recently reviewed the 10 year amortization rate adopted for DSM as of 2008/09 (per Appendix 11.43)? If yes, please provide the results. If not, why not?

RATIONALE FOR QUESTION:

Clarify the impacts of the proposed changes in the calculation of depreciation expense.

RESPONSE:

The 10 year amortization period (previously 15 years) was adopted in 2008/09 on the recommendation of the PUB in Order 116/08 to shorten the period to be consistent with industry practices. Based on Manitoba Hydro's review of similar programs offered within the industry, the 10 year amortization period falls within the range of amortization periods used by other Canadian utilities.

Section:	Appendix 5.6	**Page No.:**	Page 5
Topic:	Depreciation Expense		
Subtopic:	Depreciation Expense Breakdown		
Issue:			

PREAMBLE TO IR (IF ANY):

QUESTION:

Please breakdown depreciation expense Figure 5.7.2 for Transmission and Distribution separately.

RATIONALE FOR QUESTION:

To better determine the drivers of depreciation and amortization expense.

RESPONSE:

Please see the attached table for a further breakdown of Figure 5.7.2 Depreciation Expense for Transmission and Distribution. Please note that the Transmission and Distribution categories also include Substations which has also been broken out separately.

Further Break down of Figure 5.7.2 from Appendix 5.6

Depreciation (in millions of dollars)	2015-16 (IFRS)			2016-17 (IFRS)		
Electric Assets	Provision for Asset Removal	Change to ELG	IFRS Net Impact	Provision for Asset Removal	Change to ELG	IFRS Net Impact
Generation	$ (13)	$ 8	$ (5)	$ (14)	$ 9	$ (5)
Transmission	(4)	1	(3)	(5)	1	(4)
Substations	(20)	10	(10)	(21)	11	(10)
Distribution	(18)	10	(8)	(19)	11	(8)
Communication	(1)	2	1	(1)	1	-
General Equipment	-	-	-	-	-	-
Other (e.g. Buildings, Software)	(1)	2	1	-	2	2
Wuskwatim	(3)	3	-	(3)	3	-
Net increase (decrease) in revenue requirement	**$ (60)**	**$ 36**	**$ (24)**	**$ (63)**	**$ 38**	**$ (25)**

Section:	5	Page No.:	Appendix 5.6
Topic:	Financial Results & Forecast		
Subtopic:	Depreciation		
Issue:	ASL vs. ELG		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro continues to plan to switch to the Equal Life Group (ELG) of calculating depreciation for financial reporting purposes. However, Manitoba Hydro has previously confirmed that ELG is not prescribed by International Financial Reporting Standards (IFRS) and that the Average Service Life (ASL) method is IFRS-compatible provided proper aggregation takes place.

The Board could prescribe a different method of depreciation for ratemaking than for financial reporting if this were to be in the public interest.

QUESTION:

Confirm that IFF14 assumes a switch to ELG and a removal of net salvage in 2015/16 and that depreciation expense for the entire IFF14 period until 2034 is calculated on that basis. If not, please clarify.

RATIONALE FOR QUESTION:

This Information Request seeks to assess the impact on rates of a change to the accounting methods used to determine depreciation expense over the IFF period.

RESPONSE:

It is confirmed that IFF14 assumes a change to the ELG method of depreciation and removal of negative salvage in depreciation rates in 2015/16 through to the end of the IFF14 period 2034.

Section:	5	Page No.:	Appendix 5.6
Topic:	Financial Results & Forecast		
Subtopic:	Depreciation		
Issue:	ASL vs. ELG		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro continues to plan to switch to the Equal Life Group (ELG) of calculating depreciation for financial reporting purposes. However, Manitoba Hydro has previously confirmed that ELG is not prescribed by International Financial Reporting Standards (IFRS) and that the Average Service Life (ASL) method is IFRS-compatible provided proper aggregation takes place.

The Board could prescribe a different method of depreciation for ratemaking than for financial reporting if this were to be in the public interest.

QUESTION:

If (a) is confirmed, please provide a chart similar to Figure 5.7.1 for the entire IFF14 period.

RATIONALE FOR QUESTION:

RESPONSE:

Please see the attached chart for the net impact on depreciation expense for the 20 year period in IFF14. The cumulative net decrease to depreciation expense as a result of accounting related changes is approximately $2 billion.

	Depreciation Expense ($ millions)									
	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24
Change in service life - PP&E (net of contributions)	(25)	(29)	(30)	(30)	(34)	(38)	(43)	(41)	(43)	(42)
Overhead ineligible for Capitalization	-	-	(2)	(4)	(6)	(7)	(9)	(11)	(13)	(14)
Meter Compliance, Exchange and Sampling	-	-	-	-	-	-	-	1	1	1
Elimination of Provision for Asset Removal	-	(60)	(63)	(67)	(86)	(96)	(107)	(117)	(117)	(119)
Change in Methodology (ELG)	-	36	38	41	49	55	63	67	68	69
Net Impact on Depreciation Expense Increase (Decrease)	**(25)**	**(53)**	**(57)**	**(60)**	**(76)**	**(86)**	**(96)**	**(101)**	**(103)**	**(105)**

	Depreciation Expense ($ millions)										
	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	Total
Change in service life - PP&E (net of contributions)	(42)	(40)	(36)	(39)	(40)	(40)	(40)	(39)	(38)	(37)	(746)
Overhead ineligible for Capitalization	(16)	(18)	(20)	(22)	(23)	(25)	(27)	(29)	(31)	(33)	(310)
Meter Compliance, Exchange and Sampling	1	1	1	1	1	1	1	1	1	1	13
Elimination of Provision for Asset Removal	(120)	(122)	(125)	(127)	(130)	(132)	(134)	(136)	(140)	(143)	(2,141)
Change in Methodology (ELG)	69	70	72	73	75	76	77	79	80	81	1,238
Net Impact on Depreciation Expense Increase (Decrease)	**(108)**	**(109)**	**(108)**	**(114)**	**(117)**	**(120)**	**(123)**	**(124)**	**(128)**	**(131)**	**(1,946)**

Section:	5	Page No.:	Appendix 5.6
Topic:	Financial Results & Forecast		
Subtopic:	Depreciation		
Issue:	ASL vs. ELG		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro continues to plan to switch to the Equal Life Group (ELG) of calculating depreciation for financial reporting purposes. However, Manitoba Hydro has previously confirmed that ELG is not prescribed by International Financial Reporting Standards (IFRS) and that the Average Service Life (ASL) method is IFRS-compatible provided proper aggregation takes place.

The Board could prescribe a different method of depreciation for ratemaking than for financial reporting if this were to be in the public interest.

QUESTION:

Confirm whether the ASL-based Gannett Fleming depreciation study filed in the previous GRA was IFRS-compatible. If not, explain why not and what changes would be required for an IFRS-compatible ASL-based depreciation study (e.g., changes to asset groups, etc.)

RATIONALE FOR QUESTION:

RESPONSE:

The ASL based Gannett Fleming depreciation study filed in the previous GRA was not IFRS compliant as the level of asset componentization was not at a sufficient level to satisfy the componentization requirements of IFRS due to the wide dispersion in service lives that exists in many asset groups.

An in-depth depreciation study and auditor review would need to be conducted to identify all new asset components that would be required to develop IFRS compliant ASL based depreciation rates. Please see pages 12 and 13 of Appendix 11.49 (Manitoba Hydro

Response to PUB Order 43/13, Directives #8 & #9) of the application which provides examples of the asset component changes that would be required to continue to use the ASL method and comply with IFRS.

Section:	5	Page No.:	Appendix 5.6
Topic:	Financial Results & Forecast		
Subtopic:	Depreciation		
Issue:	ASL vs. ELG		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro continues to plan to switch to the Equal Life Group (ELG) of calculating depreciation for financial reporting purposes. However, Manitoba Hydro has previously confirmed that ELG is not prescribed by International Financial Reporting Standards (IFRS) and that the Average Service Life (ASL) method is IFRS-compatible provided proper aggregation takes place.

The Board could prescribe a different method of depreciation for ratemaking than for financial reporting if this were to be in the public interest.

QUESTION:

Provide a break-down of changes to asset classes made between the ASL-based depreciation study filed in the previous GRA and the new ELG-based study filed in the current GRA. Alternatively, confirm that there have been no material changes to the asset classes as represented in Appendix 5.6.

RATIONALE FOR QUESTION:

RESPONSE:

The breakdown of changes to asset classes made between the 2010 ASL-based depreciation study filed in Manitoba Hydro's previous GRA and the 2014 ELG based depreciation study includes only new asset classes added as part of the 2014 depreciation study. The asset class additions are as per the attached listing.

	POINTE DU BOIS - NEW
1111A	DAMS, DYKES AND WEIRS
1111E	WATER CONTROL SYSTEMS
1111F	ROADS AND SITE IMPROVEMENTS
1111P	A/C ELECTRICAL POWER SYSTEMS
1111Q	INSTRUMENTATION, CONTROL AND D/C SYSTEMS
1111R	AUXILIARY STATION PROCESSES
1111X	SUPPORT BUILDINGS
1111W	SUPPORT BUILDING RENOVATIONS
	TRANSMISSION
2000Z	COMMUNITY DEVELOPMENT COSTS
	METERS
4900W	METERING EXCHANGES
	BUILDINGS
8000F	LEASEHOLD IMPROVEMENTS - SONY PLACE
	WUSKWATIM POWER LIMITED PARTNERSHIP
	HYDRAULIC GENERATION
1181A	WPLP - DAMS, DYKES AND WEIRS
1181B	WPLP - POWERHOUSE
1181C	WPLP - POWERHOUSE RENOVATIONS
1181D	WPLP - SPILLWAY
1181E	WPLP - WATER CONTROL SYSTEMS
1181F	WPLP - ROADS AND SITE IMPROVEMENTS
1181G	WPLP - TURBINES AND GENERATORS
1181H	WPLP - GOVERNORS AND EXCITATION SYSTEM
1181P	WPLP - A/C ELECTRICAL POWER SYSTEMS
1181Q	WPLP - INSTRUMENTATION, CONTROL AND D/C SYSTEMS
1181R	WPLP - AUXILIARY STATION PROCESSES
1181X	WPLP - SUPPORT BUILDINGS
1181W	WPLP - SUPPORT BUILDING RENOVATIONS
1181Z	WPLP - OPERATIONAL EMPLOYMENT FUND
	SUBSTATIONS
3081B	WPLP - BUILDINGS
3081F	WPLP - ROADS, STEEL STRUCTURES AND CIVIL SITE WORK
3181R	WPLP - POWER TRANSFORMERS
3181T	WPLP - INTERRUPTING EQUIPMENT
3181U	WPLP - OTHER STATION EQUIPMENT
3181V	WPLP - ELECTRONIC EQUIPMENT AND BATTERIES

WUSKWATIM POWER LIMITED PARTNERSHIP cont'd

COMMUNICATION

5081H	WPLP - FIBRE OPTIC AND METALLIC CABLE
5081J	WPLP - CARRIER EQUIPMENT

MOTOR VEHICLES

6081G	WPLP - HEAVY TRUCKS
6081H	WPLP - CONSTRUCTION EQUIPMENT
6081J	WPLP - TRAILERS
6081K	WPLP - MISCELLANEOUS VEHICLES

GENERAL EQUIPMENT

9081K	WPLP - COMPUTER EQUIPMENT

WUSKWATIM POWER LIMITED PARTNERSHIP - INTANGIBLE ASSETS

TRANSMISSION

2080F	WPLP - ROADS, TRAILS AND BRIDGES
2080G	WPLP - METAL TOWERS AND CONCRETE POLES
2080J	WPLP - POLES AND FIXTURES
2080L	WPLP - OVERHEAD CONDUCTOR AND DEVICES
2080Z	WPLP - TRANSMISSION DEVELOPMENT FUND

SUBSTATIONS

3080B	WPLP - BUILDINGS
3080F	WPLP - ROADS, STEEL STRUCTURES AND CIVIL SITE WORK
3180R	WPLP - POWER TRANSFORMERS
3180S	WPLP - OTHER TRANSFORMERS
3180T	WPLP - INTERRUPTING EQUIPMENT
3180U	WPLP - OTHER STATION EQUIPMENT
3180V	WPLP - ELECTRONIC EQUIPMENT AND BATTERIES

DISTRIBUTION

4080J	WPLP - POLES AND FIXTURES
4080L	WPLP - OVERHEAD CONDUCTOR AND DEVICES
4080N	WPLP - UNDERGROUND CABLE AND DEVICES - PRIMARY
4080S	WPLP - SERIALIZED EQUIPMENT - UNDERGROUND

COMMUNICATION

5080H	WPLP - FIBRE OPTIC AND METALLIC CABLE
5080J	WPLP - CARRIER EQUIPMENT
5080M	WPLP - MOBILE RADIO, TELEPHONE AND CONFERENCING
5080N	WPLP - OPERATIONAL DATA NETWORK

EASEMENTS

A180A	WPLP - EASEMENTS

Section:	Tab 5: Appendix 5.6	Page No.:	PUB/MH I-37 (b)
Topic:	Financial Results & Forecast		
Subtopic:	Depreciation		
Issue:	ASL vs. ELG		

PREAMBLE TO IR (IF ANY):

The Board could prescribe a different method of depreciation for rate-setting purposes than used for Manitoba Hydro's financial reporting.

QUESTION:

a) Please refile the schedule eliminating the change to ELG, assuming the continuation of ASL.

b) Please indicate the equal annual percentage rate increase MH would request based on (a).

c) Please discuss the implication on financial reporting if a regulatory accounting approach to depreciation expense were to be established, discretely using ASL for rate setting purposes.

RATIONALE FOR QUESTION:

This question explores the rate impact of continuing to use ASL for rate-setting purposes.

RESPONSE:

a) Please see the attached chart for the net impact on depreciation expense for the 20 year period in IFF14 assuming the continuation of CGAAP ASL and the removal of net salvage. Consistent with the requirements of the IFRS standard, *IFRS 14 Regulatory Deferral Accounts*, the chart reflects the amortization of a new regulatory deferral account established to capture the annual and cumulative difference between depreciation expense compliant with IFRS and the CGAAP ASL depreciation expense. The deferral account is assumed to be amortized into net income over a period of 10 years. For more information on the deferral account, please see the response to part (c) of this question below.

	Depreciation Expense ($ millions)																				
	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**Total**
Change in service life - PP&E (net of contributions)	(25)	(29)	(30)	(30)	(34)	(38)	(43)	(41)	(43)	(42)	(42)	(40)	(36)	(39)	(40)	(40)	(40)	(39)	(38)	(37)	(746)
Overhead ineligible for Capitalization	-	-	(2)	(4)	(6)	(7)	(9)	(11)	(13)	(14)	(16)	(18)	(20)	(22)	(23)	(25)	(27)	(29)	(31)	(33)	(310)
Meter Compliance, Exchange and Sampling	-	-	-	-	-	-	-	1	1	1	1	1	1	1	1	1	1	1	1	1	13
Elimination of Provision for Asset Removal	-	(60)	(63)	(67)	(86)	(96)	(107)	(117)	(117)	(119)	(120)	(122)	(125)	(127)	(130)	(132)	(134)	(136)	(140)	(143)	(2 141)
Change in Methodology (ELG)	-	36	38	41	49	55	63	67	68	69	69	70	72	73	75	76	77	79	80	81	1 238
Net Impact on Depreciation Expense Increase (Decrease)	**(25)**	**(53)**	**(57)**	**(60)**	**(77)**	**(86)**	**(96)**	**(101)**	**(104)**	**(105)**	**(108)**	**(109)**	**(108)**	**(114)**	**(117)**	**(120)**	**(123)**	**(124)**	**(128)**	**(131)**	**(1 946)**

Adjustments to Response to PUB/MH I-37b

Remove: impact of changing to ELG	-	(36)	(38)	(41)	(49)	(55)	(63)	(67)	(68)	(69)	(69)	(70)	(72)	(73)	(75)	(76)	(77)	(79)	(80)	(81)	(1 238)
Add: Amortization of regulatory deferral account	-	7	11	15	20	25	31	38	45	52	59	59	62	66	68	70	72	73	74	75	921
Net Impact on Depreciation Expense Increase (Decrease)	**(25)**	**(82)**	**(84)**	**(86)**	**(106)**	**(116)**	**(127)**	**(130)**	**(127)**	**(122)**	**(118)**	**(120)**	**(118)**	**(121)**	**(124)**	**(126)**	**(128)**	**(130)**	**(134)**	**(137)**	**(2 262)**

b) Based on the assumption of the continuation of the CGAAP ASL procedure without net salvage as posed in the question, Manitoba Hydro would continue to request a rate increase of 3.95% so as to ensure the utility's financial position is strong enough to absorb future financial risks and avoid volatility in customer rates in the future.

Under this scenario, customer rate increases are projected at 3.90% annually from 2018 through to 2031 and 2.0% thereafter are required in order to achieve a 25% equity ratio by 2034, assuming a reduction in depreciation from the continued use of CGAAP ASL in conjunction with the amortization required for the new regulatory deferral account. Please see attachment 1 to this response for the projected financial statements associated with this scenario. A summary of the results is as follows:

Account	March 31, 2034
Retained Earnings (MH14)	**5 557**
Depreciation expense reduction – continue with CGAAP ASL (no net salvage)	1 238
Depreciation expense increase – amortization of Deferral Account (10 year amortization period)	(921)
Reduction in customer rate revenue via 3.90% increases	(184)
Increase in Finance expense for higher debt levels	(81)
Increase in Capital taxes for higher debt levels	(23)
Reversal of the 2015 Retained Earnings adjustment for the change to ELG depreciation	33
Ending Retained Earnings	**5 619**
Net change in Retained Earnings	**62**

As Manitoba Hydro indicated at the 2012/13 & 2013/14 GRA, the decision to remove net salvage from depreciation rates was taken in order to manage the overall impacts of the transition to IFRS, including the impacts of moving to the ELG depreciation methodology. As such, Manitoba Hydro's proposal to move to ELG and discontinue net salvage was an overall approach in order to ensure that there were no negative impacts to customers as a result of accounting policy selection by Manitoba Hydro. Manitoba Hydro's position is that, from an overall fairness perspective, the PUB should consider the impacts of the proposed depreciation changes for rate-setting purposes as a whole, rather than focusing only on the change to ELG.

In order to understand the overall implications of proposed depreciation changes for rate-setting purposes, Manitoba Hydro has developed an additional financial statement scenario that assumes the continuation of CGAAP ASL and the continuation of the inclusion of asset removal costs (i.e. net salvage) in depreciation rates for rate-setting purposes. Under this scenario, customer rate increases are projected at 3.98% annually from 2018 through to 2031 and 2.0% thereafter are required in order to achieve a 25% equity ratio by 2034. Please see attachment 2 to this response for the projected financial statements associated with this scenario. As part of this scenario, Manitoba Hydro has assumed the creation of a regulated asset deferral account to record the differences between CGAAP ASL and IFRS ELG as in the scenario above, as well as the creation of a regulated liability deferral account to record net salvage, which is not IFRS compliant. Manitoba Hydro has assumed that both the asset and liability deferral accounts would be amortized into net income over a period of 10 years. A summary of the results of this scenario are as follows:

Account	March 31, 2034
Retained Earnings (MH14)	**5 557**
Depreciation Expense increase - Provision for net salvage	(2 141)
Depreciation expense reduction – continue with CGAAP ASL (no net salvage)	1 238
Depreciation expense decrease – amortization of Deferral Liability Account (10 year amortization period)	1 588
Depreciation expense increase – amortization of Deferral Asset Account (10 year amortization period)	(921)
Increase in customer rate revenue via 3.98% increases	99
Decrease in Finance expense for lower debt levels	43
Decrease in Capital taxes for lower debt levels	17
Reversal of the 2015 Retained Earnings adjustment for the change to ELG depreciation and Net Salvage	(24)
Ending Retained Earnings	**5 456**
Net change in Retained Earnings	**(101)**

Overall, the results of the two scenarios above reinforce that Manitoba Hydro's proposed and indicative rate increases of 3.95% are not driven by the accounting changes as identified in Schedule A of Appendix 5.7 of the Application. The accounting changes only alter the timing between CGAAP and IFRS as to when such expenses are recognized into net income.

Furthermore, the PUB explicitly rejected the recommendations by intervenors at the 2012/13 & 2013/14 GRA to reduce rate increases by assuming different accounting policies for rate-setting purposes, finding at page 10 of Order 43/13:

> *"Interveners recommended various accounting changes to lessen rate increases over the test years. The Board rejects this approach as it would have the effect of reducing Manitoba Hydro's revenues, weakening its financial situation, and increasing borrowing costs. It is important that Manitoba Hydro remain a financially strong and viable organization."*

c) Manitoba Hydro has interpreted the term "*discretely using ASL for rate setting purposes*" to imply having two separate sets of financial statements, one for financial reporting purposes and one for rate-setting purposes, or preparing alternate set of depreciation calculations to assess rate requirements.

Under the scenario specified in the question, a new regulatory deferral account would have to be created consistent with the requirements of IFRS 14, to capture the annual and cumulative differences between depreciation expense compliant with IFRS and depreciation expense used for rate-setting purposes (CGAAP ASL). Net income before the impact of Regulatory Deferral Accounts would include depreciation expense compliant with IFRS (ELG) and net income after the impact of regulatory deferral accounts would include depreciation expense based on a CGAAP ASL method. This accounting treatment would be necessary to be in compliance with the financial reporting requirements of IFRS interim standard *IFRS 14 - Regulatory Deferral Accounts* which requires an all or nothing approach to recognizing rate regulated accounts. As per paragraph 8 of IFRS 14,

8 An entity that is within the scope of, and that elects to apply, this Standard shall apply all of its requirements to <u>all regulatory deferral account balances</u> that arise from <u>all of the entity's rate-regulated activities</u>.

However, the establishment of a regulatory deferral account would require Manitoba Hydro to maintain two sets of PP&E sub ledger records to support the before and after regulatory impact balances presented in the financial statements. This would require the recognition of all transactions associated with depreciation expense and gains and losses on asset retirements to be recognized in separate sub-ledgers. Going forward, cost and accumulated depreciation balances in the two sub-ledger accounts would be very different. The process for maintaining two PP&E sub-ledgers will be extremely onerous, time consuming and costly given the thousands of transactions that are recorded each year for Manitoba Hydro's $16 billion of assets. Manitoba Hydro currently has 93,000 assets with values in its subledger books and its asset balance is projected to almost double in the next 20 years. It is also anticipated that the PUB would require an audit to be performed on the PP&E related balances used for rate-setting purposes. In addition, as compared to performing a single depreciation study for financial reporting purposes, Manitoba Hydro would be required to perform two studies, one based on ELG rates and one based on ASL rates.

In addition, in order to maintain a separate set of financial statements or alternate set of depreciation calculations for rate-setting purposes, the following administrative efforts may be required:

- Monthly and quarterly financial reports;
- Annual forecasting requirements (i.e. 2 different Integrated Financial Forecasts, one for rate setting purposes and one for other users such management, financial institutions, government);
- Quarterly/annual reconciliation of PP&E related accounts;
- Annual audit of depreciation rates / expense, asset retirement gains and losses, and PP&E net book value balances; and
- Depreciation Studies

Manitoba Hydro's position is that the transition to IFRS should not trigger the requirement for a separate set of financial statements or alternate set of depreciation calculations for rate-setting purposes. These steps are not necessary under the cost of service rate-setting methodology that is used to set electric rates in Manitoba. Unlike the rate base/rate of return methodology that is used to set rates in other jurisdictions, the cost of service approach used in Manitoba does not determine rates based strictly on changes in costs and an established capital structure and return on equity. Rather the cost of service methodology coupled with Manitoba Hydro's approach of implementing regular and reasonable rate increases has the flexibility to recognize changes in costs and levels of retained earnings and transition these changes into rates gradually over time, while at the same time ensuring the maintenance of an adequate financial structure over the long-term. This approach serves to protect customers

Section:	Tab 5: App 5.6	Page No.:	Appendix 11.49 Attachment B
Topic:	Financial Results and Forecast		
Subtopic:	Depreciation Expense		
Issue:	ELG vs ASL		

PREAMBLE TO IR (IF ANY):

In its October 22, 2014 letter MH stated:

> *"In the event that the PUB determines that the ELG method should not be used for rate-setting purposes, Manitoba Hydro could continue to use the existing CGAAP ASL depreciation rates for setting customer rates. However, in consideration of Manitoba Hydro's existing asset component structure, Manitoba Hydro is adopting the ELG method for IFRS compliant financial reporting purposes (as opposed to rate setting purposes). In this circumstance, Manitoba Hydro would be required, for financial reporting purposes, to establish a rate-regulated account to capture the difference between depreciation expense recorded for rate-setting purposes (existing CGAAP ASL methodology) and depreciation expense that will be recorded for financial reporting purposes (ELG methodology). The approach to capture the differences in a rate-regulated account is an interim measure for rate-setting purposes and would subsequently have to be re-examined at a future GRA."*

QUESTION:

Please indicate whether MH has discussed with its auditors the continued use of ASL for rate setting purposes. If so, please provide the auditors' report.

RATIONALE FOR QUESTION:

To explore the use of a different depreciation methodology for rate-setting.

RESPONSE:

In Manitoba Hydro's letter of October 22, 2014, the approach to capture in a rate regulated account the difference between depreciation expense recorded for rate setting purposes using the existing CGAAP ASL methodology and depreciation expense recorded for financial reporting purposes using the ELG methodology was identified as an interim measure only in the event that the PUB did not accept ELG for rate-setting purposes. PUB/MH-II-21c identifies the impacts associated with the requirement to maintain two sets of PP&E sub-ledger records on an ongoing basis to support the net income before and after regulatory balances as presented in the financial statements. The response to PUB/MH-II-21b also indicates that the rate increases assuming the continued use of ASL under CGAAP for rate-setting purposes are essentially the same as for the use of ELG for rate-setting purposes, thus providing no benefit to customers for the added costs.

While Manitoba Hydro has discussed with its auditors Ernst & Young the use of a regulatory deferral account for capturing the difference between depreciation used for rate-setting purposes and depreciation used for financial reporting purposes, the Corporation does not have a formal report on this matter.

Section:	Appendix 5.6	Page No.:	
Topic:	Depreciation		
Subtopic:	Detailed Calculation Example		
Issue:			

PREAMBLE TO IR (IF ANY):

In the 2012/13 & 2013/14 GRA Hydro provided MH Exhibit #59 which provided an illustrative example with two detailed calculations of an investment installed in 1923 with a lifespan of 2063 assuming plant installed in 2013 with a life span of 2063.

QUESTION:

Please provide a copy of MH Exhibit #59 from the 2012/13 & 2013/14 GRA with any revisions needed for accurate representation between the ASL and ELG methods used for the 2014 Depreciation Study?

RATIONALE FOR QUESTION:

MIPUG is reviewing the depreciation study including any changes that have occurred since the 2010 depreciation study.

RESPONSE:

The illustrative examples provided for in MH Exhibit #59 of the 2012/13 & 2013/14 GRA Hydro are still relevant and as such do not require further updating. As MH Exhibit #59 was prepared by Gannet Fleming, the results provided in this response have also been prepared by Gannett Fleming.

Please note that the ASL procedure as applied in this example is not IFRS compliant as there likely would be a requirement to componentize the investment further so as to ensure the applied ASL procedure complies with the requirements of IFRS. In addition, the ASL example fails to recognize annual losses on asset retirements. As a result, this simplistic example cannot be relied upon to understand the differences between ELG and an IFRS compliant ASL methodology for Manitoba Hydro.

The example provided in Appendix 11.49 (page 10) Manitoba Hydro's Response to Order 43/13, Directives 8 & 9, the recognition of annual asset retirement losses under the ASL procedure can result in an overall annual expense (depreciation plus retirement losses) that is greater than the depreciation expense determined under the ELG method. In addition, it is likely that under IFRS, there would be a requirement.

For further information on the differences between the ELG and ASL procedures, please refer to Appendix 11.49 of the application.

Copy of Exhibit #59 from the 2012/13 & 2013/14 GRA:

Please refer to the following schedules, which provide annual depreciation rates calculated using both the Equal Life Group and Average Service Life Procedures for the two cases requested. The depreciation rates were calculated using the following assumptions:

Case 1

- $1,000 of investment is added in 1923 with an anticipated Life span ending in 2063.
- A small portion of the original investment will retire each year in accordance with the Iowa R4-125 survivor curve. The Anticipated Closing Balance reflects this small amount of annual retirement.
- The anticipated loss on retirement that would result in the ASL procedure has not been considered in this analysis.
- The total original cost of $1,000 is fully recovered in both procedures.

Case 2

- $1,000 of investment is added in 2013 with an anticipated Life span ending in 2063.
- A small portion of the original investment will retire each year in accordance with the Iowa R4-125 survivor curve. The Anticipated Closing Balance reflects this small amount of annual retirement.
- The anticipated loss on retirement that would result in the ASL procedure has not been considered in this analysis.
- The total original cost of $1,000 is fully recovered in both procedures.

Case 1 - Annual Depreciation Rates for the years 1923 through 2063 incorporating the Equal Life Group and Average Service Life Grouping Procedures

		ELG		ASL	
	Anticipated Closing Balance ($)	Annual Rate (%)	Annual Expense ($)	Annual Rate (%)	Annual Expense ($)
1923	1,000.00	0.87%	8.70	0.823%	8.23
1924	999.99	0.87%	8.70	0.823%	8.23
1925	999.98	0.87%	8.70	0.823%	8.23
1926	999.97	0.87%	8.70	0.823%	8.23
1927	999.96	0.87%	8.70	0.823%	8.23
1928	999.95	0.87%	8.70	0.823%	8.23
1929	999.94	0.87%	8.70	0.823%	8.23
1930	999.93	0.87%	8.70	0.823%	8.23
1931	999.91	0.87%	8.70	0.823%	8.23
1932	999.89	0.87%	8.70	0.823%	8.23
1933	999.87	0.87%	8.70	0.823%	8.23
1934	999.85	0.87%	8.70	0.823%	8.23
1935	999.83	0.87%	8.70	0.823%	8.23
1936	999.80	0.86%	8.60	0.823%	8.23
1937	999.77	0.86%	8.60	0.823%	8.23
1938	999.74	0.86%	8.60	0.823%	8.23
1939	999.70	0.86%	8.60	0.823%	8.23
1940	999.66	0.86%	8.60	0.823%	8.23
1941	999.62	0.86%	8.60	0.823%	8.23
1942	999.57	0.86%	8.60	0.823%	8.23
1943	999.52	0.86%	8.60	0.823%	8.23
1944	999.46	0.86%	8.60	0.823%	8.23
1945	999.40	0.86%	8.59	0.823%	8.23
1946	999.33	0.86%	8.59	0.823%	8.22
1947	999.25	0.86%	8.59	0.823%	8.22
1948	999.16	0.86%	8.59	0.823%	8.22
1949	999.07	0.86%	8.59	0.823%	8.22
1950	998.97	0.86%	8.59	0.823%	8.22
1951	998.86	0.86%	8.59	0.823%	8.22
1952	998.74	0.86%	8.59	0.823%	8.22
1953	998.61	0.86%	8.59	0.823%	8.22
1954	998.47	0.86%	8.59	0.823%	8.22
1955	998.32	0.86%	8.59	0.823%	8.22
1956	998.15	0.86%	8.58	0.823%	8.21
1957	997.96	0.86%	8.58	0.823%	8.21
1958	997.76	0.86%	8.58	0.823%	8.21
1959	997.54	0.86%	8.58	0.823%	8.21
1960	997.31	0.86%	8.58	0.823%	8.21

Case 1 - Annual Depreciation Rates for the years 1923 through 2063 incorporating the Equal Life Group and Average Service Life Grouping Procedures

		ELG		ASL	
	Anticipated Closing Balance ($)	Annual Rate (%)	Annual Expense ($)	Annual Rate (%)	Annual Expense ($)
1961	997.05	0.86%	8.57	0.823%	8.21
1962	996.77	0.86%	8.57	0.823%	8.20
1963	996.47	0.86%	8.57	0.823%	8.20
1964	996.15	0.86%	8.57	0.823%	8.20
1965	995.81	0.86%	8.56	0.823%	8.20
1966	995.43	0.86%	8.56	0.823%	8.19
1967	995.03	0.85%	8.46	0.823%	8.19
1968	994.60	0.85%	8.45	0.823%	8.19
1969	994.14	0.85%	8.45	0.823%	8.18
1970	993.65	0.85%	8.45	0.823%	8.18
1971	993.11	0.85%	8.44	0.823%	8.17
1972	992.53	0.85%	8.44	0.823%	8.17
1973	991.92	0.85%	8.43	0.823%	8.16
1974	991.27	0.85%	8.43	0.823%	8.16
1975	990.57	0.85%	8.42	0.823%	8.15
1976	989.81	0.85%	8.41	0.823%	8.15
1977	989.01	0.85%	8.41	0.823%	8.14
1978	988.15	0.84%	8.30	0.823%	8.13
1979	987.24	0.84%	8.29	0.823%	8.12
1980	986.28	0.84%	8.28	0.823%	8.12
1981	985.24	0.84%	8.28	0.823%	8.11
1982	984.14	0.84%	8.27	0.823%	8.10
1983	982.97	0.84%	8.26	0.823%	8.09
1984	981.73	0.84%	8.25	0.823%	8.08
1985	980.42	0.84%	8.24	0.823%	8.07
1986	979.01	0.84%	8.22	0.823%	8.06
1987	977.52	0.84%	8.21	0.823%	8.04
1988	975.95	0.84%	8.20	0.823%	8.03
1989	974.30	0.84%	8.18	0.823%	8.02
1990	972.56	0.83%	8.07	0.823%	8.00
1991	970.70	0.83%	8.06	0.823%	7.99
1992	968.74	0.83%	8.04	0.823%	7.97
1993	966.68	0.83%	8.02	0.823%	7.96
1994	964.51	0.83%	8.01	0.823%	7.94
1995	962.23	0.83%	7.99	0.823%	7.92
1996	959.80	0.83%	7.97	0.823%	7.90
1997	957.25	0.83%	7.95	0.823%	7.88
1998	954.58	0.82%	7.83	0.823%	7.86

Case 1 - Annual Depreciation Rates for the years 1923 through 2063 incorporating the Equal Life Group and Average Service Life Grouping Procedures

		ELG		ASL	
	Anticipated Closing Balance ($)	Annual Rate (%)	Annual Expense ($)	Annual Rate (%)	Annual Expense ($)
1999	951.79	0.82%	7.80	0.823%	7.83
2000	948.87	0.82%	7.78	0.823%	7.81
2001	945.77	0.82%	7.76	0.823%	7.78
2002	942.53	0.82%	7.73	0.823%	7.76
2003	939.14	0.82%	7.70	0.823%	7.73
2004	935.60	0.81%	7.58	0.823%	7.70
2005	931.91	0.81%	7.55	0.823%	7.67
2006	928.01	0.81%	7.52	0.823%	7.64
2007	923.95	0.81%	7.48	0.823%	7.60
2008	919.72	0.81%	7.45	0.823%	7.57
2009	915.32	0.81%	7.41	0.823%	7.53
2010	910.75	0.80%	7.29	0.823%	7.50
2011	905.94	0.80%	7.25	0.823%	7.46
2012	900.95	0.80%	7.21	0.823%	7.41
2013	895.77	0.80%	7.17	0.823%	7.37
2014	890.40	0.80%	7.12	0.823%	7.33
2015	884.84	0.80%	7.08	0.823%	7.28
2016	879.02	0.79%	6.94	0.823%	7.23
2017	873.00	0.79%	6.90	0.823%	7.18
2018	866.77	0.79%	6.85	0.823%	7.13
2019	860.34	0.79%	6.80	0.823%	7.08
2020	853.70	0.79%	6.74	0.823%	7.03
2021	846.78	0.78%	6.60	0.823%	6.97
2022	839.65	0.78%	6.55	0.823%	6.91
2023	832.30	0.78%	6.49	0.823%	6.85
2024	824.73	0.78%	6.43	0.823%	6.79
2025	816.95	0.78%	6.37	0.823%	6.72
2026	808.88	0.77%	6.23	0.823%	6.66
2027	800.58	0.77%	6.16	0.823%	6.59
2028	792.05	0.77%	6.10	0.823%	6.52
2029	783.28	0.77%	6.03	0.823%	6.45
2030	774.26	0.77%	5.96	0.823%	6.37
2031	764.88	0.77%	5.89	0.823%	6.29
2032	755.20	0.76%	5.74	0.823%	6.22
2033	745.20	0.76%	5.66	0.823%	6.13
2034	734.87	0.76%	5.59	0.823%	6.05
2035	724.19	0.76%	5.50	0.823%	5.96
2036	713.01	0.76%	5.42	0.823%	5.87

Case 1 - Annual Depreciation Rates for the years 1923 through 2063 incorporating the Equal Life Group and Average Service Life Grouping Procedures

		ELG		ASL	
	Anticipated Closing Balance ($)	Annual Rate (%)	Annual Expense ($)	Annual Rate (%)	Annual Expense ($)
2037	701.44	0.75%	5.26	0.823%	5.77
2038	689.46	0.75%	5.17	0.823%	5.67
2039	677.06	0.75%	5.08	0.823%	5.57
2040	664.24	0.75%	4.98	0.823%	5.47
2041	650.85	0.75%	4.88	0.823%	5.36
2042	637.04	0.74%	4.71	0.823%	5.24
2043	622.81	0.74%	4.61	0.823%	5.13
2044	608.18	0.74%	4.50	0.823%	5.01
2045	593.15	0.74%	4.39	0.823%	4.88
2046	577.63	0.73%	4.22	0.823%	4.75
2047	561.77	0.73%	4.10	0.823%	4.62
2048	545.59	0.73%	3.98	0.823%	4.49
2049	529.13	0.73%	3.86	0.823%	4.35
2050	512.40	0.73%	3.74	0.823%	4.22
2051	495.39	0.73%	3.62	0.823%	4.08
2052	478.22	0.72%	3.44	0.823%	3.94
2053	460.92	0.72%	3.32	0.823%	3.79
2054	443.53	0.72%	3.19	0.823%	3.65
2055	426.08	0.72%	3.07	0.823%	3.51
2056	408.63	0.72%	2.94	0.823%	3.36
2057	391.24	0.72%	2.82	0.823%	3.22
2058	373.94	0.71%	2.65	0.823%	3.08
2059	356.76	0.71%	2.53	0.823%	2.94
2060	339.74	0.71%	2.41	0.823%	2.80
2061	323.00	0.71%	2.29	0.823%	2.66
2062	306.52	0.71%	2.18	0.823%	2.52
2063	289.87	0.71%	2.06	0.823%	2.39
			1,000.81		1,000.37

Case 2 - Annual Depreciation Rates for the years 2013 through 2063 incorporating the Equal Life Group and Average Service Life Grouping Procedures

		ELG		ASL	
	Anticipated Closing Balance ($)	Annual Rate (%)	Annual Expense ($)	Annual Rate (%)	Annual Expense ($)
2013	1000	0.99%	9.90	0.99%	9.90
2014	999.99	1.99%	19.90	1.98%	19.82
2015	999.98	1.99%	19.90	1.98%	19.82
2016	999.97	1.99%	19.90	1.98%	19.82
2017	999.96	1.99%	19.90	1.98%	19.82
2018	999.95	1.99%	19.90	1.98%	19.82
2019	999.94	1.99%	19.90	1.98%	19.82
2020	999.93	1.99%	19.90	1.98%	19.82
2021	999.91	1.99%	19.90	1.98%	19.82
2022	999.89	1.99%	19.90	1.98%	19.82
2023	999.87	1.99%	19.90	1.98%	19.82
2024	999.85	1.99%	19.90	1.98%	19.82
2025	999.83	1.99%	19.90	1.98%	19.82
2026	999.8	1.99%	19.90	1.98%	19.82
2027	999.77	1.99%	19.90	1.98%	19.82
2028	999.74	1.99%	19.89	1.98%	19.81
2029	999.7	1.99%	19.89	1.98%	19.81
2030	999.66	1.99%	19.89	1.98%	19.81
2031	999.62	1.98%	19.79	1.98%	19.81
2032	999.57	1.98%	19.79	1.98%	19.81
2033	999.52	1.98%	19.79	1.98%	19.81
2034	999.46	1.98%	19.79	1.98%	19.81
2035	999.4	1.98%	19.79	1.98%	19.81
2036	999.33	1.98%	19.79	1.98%	19.81
2037	999.25	1.98%	19.79	1.98%	19.81
2038	999.16	1.98%	19.78	1.98%	19.80
2039	999.07	1.98%	19.78	1.98%	19.80
2040	998.97	1.98%	19.78	1.98%	19.80
2041	998.86	1.98%	19.78	1.98%	19.80
2042	998.74	1.98%	19.78	1.98%	19.80
2043	998.61	1.98%	19.77	1.98%	19.79
2044	998.47	1.98%	19.77	1.98%	19.79
2045	998.32	1.98%	19.77	1.98%	19.79
2046	998.15	1.98%	19.76	1.98%	19.78
2047	997.96	1.98%	19.76	1.98%	19.78
2048	997.76	1.98%	19.76	1.98%	19.78
2049	997.54	1.98%	19.75	1.98%	19.77
2050	997.31	1.98%	19.75	1.98%	19.77
2051	997.05	1.98%	19.74	1.98%	19.76

Case 2 - Annual Depreciation Rates for the years 2013 through 2063 incorporating the Equal Life Group and Average Service Life Grouping Procedures

		ELG		ASL	
	Anticipated Closing Balance ($)	Annual Rate (%)	Annual Expense ($)	Annual Rate (%)	Annual Expense ($)
2052	996.77	1.98%	19.74	1.98%	19.76
2053	996.47	1.98%	19.73	1.98%	19.75
2054	996.15	1.98%	19.72	1.98%	19.74
2055	995.81	1.98%	19.72	1.98%	19.74
2056	995.43	1.98%	19.71	1.98%	19.73
2057	995.03	1.98%	19.70	1.98%	19.72
2058	994.6	1.98%	19.69	1.98%	19.71
2059	994.14	1.98%	19.68	1.98%	19.70
2060	993.65	1.98%	19.67	1.98%	19.69
2061	993.11	1.98%	19.66	1.98%	19.68
2062	992.53	1.98%	19.65	1.98%	19.67
2063	992.53	1.98%	19.65	1.98%	19.67
			999.74		999.04

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Section:	Tab 5: Appendix 5.6 Attachment 4	Page No.:	4 of 14
Topic:	Financial Results & Forecast		
Subtopic:	Depreciation Expense		
Issue:	Changes in 2014 Depreciation Study		

PREAMBLE TO IR (IF ANY):

Gannet Flemming (GF) has indicated that ELG and ASL were both acceptable approaches under IFRS. MH has stated previously IAS 16 does not require that the Equal Life Group (ELG) method be used for determining depreciation rates as both the Average Service Life (ASL) and ELG method are acceptable methods for determining depreciation rates under IFRS.

QUESTION:

Please confirm that IAS 16 under IFRS does not preclude the use of ASL for financial reporting purposes or regulatory purposes.

RATIONALE FOR QUESTION:

To assess impacts and usage of ELG methodology and ASL methodology for regulatory purposes in other jurisdictions.

RESPONSE:

Manitoba Hydro confirms that IFRS section IAS 16 Property, plant and equipment does not preclude the use of the ASL method of depreciation for financial reporting purposes. However, the more explicit requirements of IAS 16 permit the use of the ASL method for calculating depreciation expense for financial reporting purposes only when a sufficient level of asset componentization exists. Manitoba Hydro's current level of asset componentization is not at a sufficient level to satisfy the componentization requirements of IFRS.

Section:	Tab 5: Appendix 5.6 Attachment 4	Page No.:	4 of 14
Topic:	Financial Results & Forecast		
Subtopic:	Depreciation Expense		
Issue:	Changes in 2014 Depreciation Study		

PREAMBLE TO IR (IF ANY):

Gannet Flemming (GF) has indicated that ELG and ASL were both acceptable approaches under IFRS. MH has stated previously IAS 16 does not require that the Equal Life Group (ELG) method be used for determining depreciation rates as both the Average Service Life (ASL) and ELG method are acceptable methods for determining depreciation rates under IFRS.

QUESTION:

Please update GF response to PUB/MH I-85 (a) from the 2012 GRA and indicate the number of utilities in Canada and the United states that are using ASL.

RATIONALE FOR QUESTION:

To assess impacts and usage of ELG methodology and ASL methodology for regulatory purposes in other jurisdictions.

RESPONSE:

Please refer to the attached document which provides a detailed listing of the utilities throughout North America that are currently using the ELG procedure. Virtually all other utilities not on the attached list would be using the ASL procedure or would not yet have received authorization from their regulator to use the ELG procedure.

The following attachment was provided by Gannett Fleming.

Attachment 1

DETAILED LIST OF UTILITIES THROUGHOUT NORTH AMERICA USING ELG PROCEDURE

Company Name	Approved by:
Allegheny Energy Supply, Inc.	Gannett Fleming cannot confirm that ELG has been approved
AltaGas Utilities Inc.	Alberta Utilities Commission
ATCO Gas	Alberta Utilities Commission
ATCO Electric	Alberta Utilities Commission
Aqua Pennsylvania	Pennsylvania Public Utilities Commission
Citizens Energy Group	Gannett Fleming cannot confirm that ELG has been approved
Columbia Gas of Kentucky	Kentucky Public Service Commission
Columbia Gas of Pennsylvania	Pennsylvania Public Utilities Commission
Duquesne Light Company	Pennsylvania Public Utilities Commission
Duke Energy Indiana	Indiana Utility Regulatory Commission
Duke Energy Kentucky	Kentucky Public Service Commission
East Kentucky Power Cooperative	Kentucky Public Service Commission
Enmax Power Corporation	Alberta Utilities Commission
FortisAlberta Utilities, Inc.	Alberta Utilities Commission
Kokomo Gas and Fuel Company	Indiana Utility Regulatory Commission
National Fuel Gas Distribution Corp - Pa Division	Pennsylvania Public Utilities Commission
Newfoundland Power Limited	Newfoundland and Labrador Board of Commissioners of Public Utilities
Northern Indiana Fuel and Light Company Inc.	Indiana Utility Regulatory Commission
Northern Indiana Public Service Company	Indiana Utility Regulatory Commission
Northland Utilities (NWT) Limited	Northwest Territories Public Utilities Board
Northland Utilities (Yellowknife) Limited	Northwest Territories Public Utilities Board
Nova Scotia Power, Inc.	Nova Scotia Utility and Review Board
Pennsylvania American Water Company	Pennsylvania Public Utilities Commission
Peoples Equitable Gas	Pennsylvania Public Utilities Commission
Peoples Natural Gas	Pennsylvania Public Utilities Commission
Peoples TWP	Pennsylvania Public Utilities Commission
Public Service Company of Colorado	Colorado Public Utilities Commission
Quilliq Power Corporation	Nunavut Utility Rates Review Council
UGI Penn Natural Gas, Inc.	Pennsylvania Public Utilities Commission
UGI Utilities, Inc. - Electric Division	Pennsylvania Public Utilities Commission
York Water Company	Pennsylvania Public Utilities Commission

Section:	Tab 5: Appendix 5.6 Attachment 4	Page No.:	4 of 14
Topic:	Financial Results & Forecast		
Subtopic:	Depreciation Expense		
Issue:	Changes in 2014 Depreciation Study		

PREAMBLE TO IR (IF ANY):

Gannet Flemming (GF) has indicated that ELG and ASL were both acceptable approaches under IFRS. MH has stated previously IAS 16 does not require that the Equal Life Group (ELG) method be used for determining depreciation rates as both the Average Service Life (ASL) and ELG method are acceptable methods for determining depreciation rates under IFRS.

QUESTION:

Please provide the composite weighted average rate by Class under the ASL versus ELG methodology for 2015/16 rates.

RATIONALE FOR QUESTION:

To assess impacts and usage of ELG methodology and ASL methodology for regulatory purposes in other jurisdictions.

RESPONSE:

Please see the attached table for the composite weighted average depreciation rates by class under the ASL and ELG methodologies as per the 2014 depreciation study. The ELG rates were used for the forecast of depreciation expense for fiscal 2015/16 under IFRS. The ASL rates are only applicable for fiscal 2014/15 under CGAAP.

MANITOBA HYDRO - ELECTRIC OPERATIONS
SUMMARY OF DEPRECIATION ACCRUAL PERCENTAGES

Plant Group	ELG Rates	ASL Rates*
Generation		
Hydro	1.54%	1.65%
Thermal	3.44%	3.47%
Diesel	4.03%	3.84%
Transmission	1.28%	1.58%
Substations	2.40%	2.71%
Distribution	1.98%	2.24%
General	5.27%	5.13%
Total Plant In Service	2.24%	2.41%

* Please note these rates are not IFRS compliant

Chapter:	**P. Bowman Direct Testimony Section 7.1**	**Page No.:**	**25 Line 8**
Topic:	**Depreciation Methodology for Peer Hydro Electric Utilities**		
Subtopic:			
Issue:	**Peer Utility Depreciation Practices**		

PREAMBLE TO IR:

QUESTION:

a) Please provide a listing of Peer Canadian hydroelectric generation companies that utilized ASL for depreciation purposes.

RATIONALE FOR QUESTION:

RESPONSE:

(a)

Mr. Bowman does not maintain a comprehensive list of utilities on a routine basis. For the purposes of this response, Mr. Bowman notes that the following table was originally provided in the 2012 Pre-Filed Testimony of Patrick Bowman. It has been updated to present day for the purposes of this response.

Also note the following incorrect information filed by Hydro in this proceeding:

- In response to MIPUG/MH II-7, Hydro (Gannet Fleming) incorrectly states that Newfoundland & Labrador Hydro uses ELG, when the utility actually uses ASL as outlined in the Board of Commissioners of Public Utilities Order P.U. 40 (2012) at the culmination of the 2012 Depreciation Methodology review, link provided below.

- In response to PUB/MH I-42b, Hydro (Gannett Fleming) incorrectly states that Qulliq Energy Corporation (formerly Nunavut Power) uses ELG. This is not correct as the utility uses the ASL method as shown in the QEC 2010 GRA[1]

Table 1: Depreciation Methods for Crown-Owned Canadian Utilities

Utility	Depreciation Expense Calculation Method	Study Date
BC Hydro	Average Service Life Method[2]	Gannett Fleming in 2006
BC Transmission Corporation	Average Service Life Method[3]	Gannett Fleming in 2005
Newfoundland and Labrador Hydro	Average Service Life Method[4]	Gannett Fleming in 2011
SaskPower	Average Service Life Method [5]	Gannett Fleming in 2011
Yukon Energy Corporation	Average Service Life Method[6]	KPMG in 2012
Qulliq Energy Corporation (Nunavut)	Average Service Life Method[7]	Gannett Fleming in 2010
Northwest Territories Power Corporation	Average Service Life Method[8]	Gannett Fleming in 2012
FortisBC	Average Service Life Method[9]	Gannett Fleming in 2011
Ontario Power Generation	Average Service Life Method[10]	Gannett Fleming in 2013
Nova Scotia Power	Average Service Life Method[11]	Gannett Fleming in 2010
Hydro One	Average Service Life Method[12]	Foster Associates 2011

[1] http://www.qec.nu.ca/home/index.php?option=com_docman&task=doc_download&gid=542 at page 183 of the pdf document.
[2] BC Hydro and Power Authority F2012 - 2014 Revenue Requirements Application; Appendix G: Gannett Fleming Report on IFRS Componentization. Page 8-11 (March 1, 2011). http://www.bcuc.com/Documents/Proceedings/2011/DOC_27065_B-1_BCHydro_F12_F14-RR-application.pdf.
[3] British Columbia Transmission Corporation Transmission Revenue Requirement Application. BCUC Information Request 1.63 (July 4, 2006). http://transmission.bchydro.com/nr/rdonlyres/c18a2158-e202-464a-8613-6e474d0c33df/0/bcucir1masterdocument4july2006.pdf.
[4] Newfoundland and Labrador Board of Commissioners of Public Utilities, P.U.40 (2012). Page 4. (December 31, 2012). http://www.pub.nf.ca/applications/NLH2012Depreciation/files/order/pu40-2012.pdf.
[5] SaskPower 2014, 2015, 2016 Rate Application. Section 3.2.1.2: Depreciation & Amortization. Page 31 (October 2013) http://www.saskpower.com/wp-content/uploads/2014-15-16_rate_application.pdf.
[6] Yukon Energy Corporation, 2012 General Rate Application. Tab 10: Depreciation Study by KPMG. Page 10-7 (April, 2012). http://yukonutilitiesboard.yk.ca/pdf/YEC%202012%20General%20Rate%20Application/1338_YEC%202012_2013%20GRA%20FINAL_2012%2004%2027%20Tabs%201-11.pdf.
[7] Qulliq Energy Corporation, 2010/11 General Rate Application. Page 3-10 and Appendix C-2. (September 2010). http://www.qec.nu.ca/home/index.php?option=com_content&task=view&id=175&Itemid=0.
[8] Northwest Territories Power Corporation, 2012/13 and 2013/14 General Rate Application. Page 3-13 and Appendix A-2. (March 2012).
[9] FortisBC Application for Approval of 2012-2013 Revenue Requirements and Review of 2012 Integrated System Plan. Appendix J 2011 Depreciation Study. Page 2 of 167. (June 6, 2011). http://www.fortisbc.com/About/RegulatoryAffairs/ElecUtility/Documents/FortisBC%20-%202012%20and%202013%20Revenue%20Requirements%20Application%20-%2030Jun11.pdf.
[10] Ontario Power Generation, Assessment of Regulated Asset Depreciation Rates and Generating Station Lives. (November 2013). http://www.opg.com/about/regulatory-affairs/Documents/2014-2015/F5-03-01%20Depreciation%20Study_20131205.pdf.
[11] Nova Scotia Utility and Review Board, NAUARB-NSPI-P-891, http://nsuarb.novascotia.ca/sites/default/files/documents/electricityarchive/depreciation.pdf.

RATIONALE FOR REFUSAL TO FULLY ANSWER THE QUESTION:

[12] Hydro One, 2011 Depreciation Rate Review, Ontario Energy Board EB-2012-0031, Exhibit C1-8-1, Attachment 1. Page 3. The Ontario Energy Board accepted the costs flowing from the depreciation review for the purpose of supporting transmission rates in the test year. 2014 Rate Order. January 9, 2014. http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/search/rec?sm_udf10=EB-2012-0031&sortd1=rs_dateregistered&rows=200.

CAC/MH I-47

Subject: **Depreciation**
Reference: **Tab 4, Page 5 Lines 6 & 7**

Preamble: **Manitoba Hydro states "… partially offset by the change to the Equal Life Group methodology for calculating depreciation rates (as required with the transition to IFRS)."**

a) **Provide specific cites in IFRS pronouncements that require the use of Equal Life Group methodology and provide a copy of the cited references, together with copies of the pages containing those cites.**

ANSWER:

IAS 16 does not require that the Equal Life Group (ELG) method be used for determining depreciation rates as both the Average Service Life (ASL) and ELG method are acceptable methods for determining depreciation rates under IFRS.

The specific references from the IFRS pronouncements that MH considered regarding the change to the ELG methodology are as follows:

IFRS section IAS 16 Property, Plant & Equipment paragraphs:

50 The depreciable amount of an asset shall be allocated on a systematic basis over its useful life.

57 The useful life of an asset is defined in terms of the asset's expected utility to the entity. ,…, The estimation of the useful life of the asset is a matter of judgement based on the experience of the entity with similar assets.

60 The depreciation method used shall reflect the pattern in which the asset's future economic benefits are expected to be consumed by the entity.

68 The gain or loss arising from the de-recognition of an item of property, plant and equipment shall be included in profit and loss when the item is derecognized (unless IAS 17 requires otherwise on a sale and leaseback). Gains shall not be classified as revenue."

(Please note that MH is not in a position to provide copies of the pages containing the particular reference due to copyright laws.)

Under the ASL method, the depreciation rate is based on the average life of all assets within the overall component class. The calculation of the ELG depreciation rate is more robust and is based on the expected retirement pattern for similar asset groups within the overall asset component class. Rather than determining a depreciation rate using an overall average life of the entire asset component class, the ELG method breaks the larger class into sub-components groups with similar lives and factors the different service lives of the sub-components into the overall depreciation rate for the larger component class. As such, the ELG method provides a better matching of depreciation expense with the expected consumption of the asset, which complies with the requirements of IAS 16.

The IAS 16 requirement to recognize gains and losses on asset retirements immediately in net income is significantly different than the existing GAAP accounting practice that permits the recognition of annual gains and losses in accumulated depreciation. Differences in how depreciation rates are calculated under the ASL and ELG methods will influence the extent of annual asset retirement gains and losses that will be required to be recognized in net income under IFRS and will thus, influence the method to be chosen by an entity.

Since most assets are removed from service either before or after the average service life of the overall component class, it is expected that the extent of material gains and losses to be recognized in net income under IFRS would be higher when using the ASL method. The ELG calculated rate is expected to more accurately reflect the service life of the individual assets within the larger component class and thus, assets are more likely to be fully depreciated when they are removed from service under the ELG method; reducing any gain or loss.

The ELG method will minimize the amount of gains and losses recognized on retirement of assets, and will reduce net income volatility. As a result, the ELG method is the preferred approach for rate-regulated utilities as it is expected to promote rate stability for customers.

Section:	MH-55 from the 2012/13 & 2013/14 GRA	Page No.:	
Topic:	Accounting Changes		
Subtopic:			
Issue:			

PREAMBLE TO IR (IF ANY):

QUESTION:

Please update PUB/MH I -55 from the 2012/13 & 2013/14 GRA comparing different jurisdictions regarding IFRS changes.

RATIONALE FOR QUESTION:

To review the proposed accounting changes, the implications on rate payers and how those implications have changed since the 2012/13 & 2013/14 GRA.

RESPONSE:

The following information is an update to previous GRA responses provided by Manitoba Hydro regarding the application of IFRS in different Canadian jurisdictions. The information provided is based on publically available records. Updated tables as presented in PUB/MH 1-55 from the 2012/13 & 2013/14 GRA with respect to the implementation of IFRS for Manitoba Hydro and for rate regulated utilities in Ontario and Alberta are included in Attachment 1. References used in the compilation of this response are provided in Attachment 2.

For rate regulated distributors in Ontario that adopt IFRS for financial reporting, such entities are also required to apply IFRS for rate setting purposes. The OEB has indicated that it will continue to use deferral and variance accounts where appropriate, but has also expressed its concerns with the additional work utilities may have to incur to maintain separate records for financial reporting and rate setting purposes as follows:

OEB - EB 2008-048, Transition to International Financial Reporting Standards, page 8, *The Board recognizes that minimization of differences between financial and regulatory accounting is desirable where it is feasible. Large differences between financial accounting and regulatory accounting will inevitably result in increased administrative costs to utilities and, if those costs are passed into rates, to their ratepayers.*

For Alberta based utilities adopting IFRS, the AUC published Rule 026, Regulatory Account Procedures Pertaining to the Implementation of the International Financial Reporting Standards. Similar to the OEB, the AUC requires entities adopting IFRS to use IFRS for rate setting purposes subject to AUC regulatory requirements, which are identified in the tables in Attachment 1 to this response.

The number of major Canadian utilities converting to US GAAP is significant and includes Fortis BC, Fortis Alberta, Hydro One, Ontario Power Group and Hydro Quebec. The change to US GAAP has been driven by the continued uncertainty as to whether or not the IASB will in the future adopt a permanent standard permitting the recognition of rate regulated accounting. Most of these utilities applied for and received permission from the Ontario Securities Commission (OSC) for an exemption to apply US GAAP up to January 1, 2019 which allows time for the IASB to complete its projects on rate regulated activities. While Manitoba Hydro is not in possession of all regulatory pronouncements on this issue, its general understanding is that most of the utilities that moved to US GAAP also requested and obtained approval from their regulators to use US GAAP for rate-setting purposes.

	Regulatory Assets and Liabilities
IFRS	On January 30, 2014 the IASB issued an interim standard IFRS 14 – *Regulatory Deferral Accounts* effective January 1, 2016 with earlier application permitted. The interim standard will permit first time adopters of IFRS to continue to account for regulatory deferral account balances in accordance with their previous accounting policies. On September 17, 2014 the IASB issued a Discussion paper *Reporting the Financial Effects of Rate Regulation* as part of its comprehensive project on rate regulated activities. The Discussion paper does not provide specific accounting proposals but explores a number of possible approaches that the IASB could consider when deciding how best to report the financial effects of rate regulation. The deadline for comments for the Discussion paper was January 15, 2015. In early March 2015 the Rate Regulated Activities consultative group met to discuss comments received in response to the Discussion Paper. Next steps will be the development of recommendations for the IASB.
MH Current	MH recognizes the impact of rate-regulation by applying various accounting policies that allow for the deferral of certain costs or credits which will be recovered or refunded in future rates.
MH Proposed	Manitoba Hydro will early adopt the interim standard IFRS 14 – *Regulatory Deferral Accounts* on transition to IFRS effective April 1, 2015.
OEB	The OEB will continue to use deferral and variance accounts for rate making in appropriate circumstances, whether or not these accounts are recognized under IFRS.
AUC	Utilities shall maintain the existing practice of applying to the Commission for approval of any deferral accounts that may be required for the purpose of establishing Regulatory Assets and Liabilities and proposing the mechanism for their disposition.

	Property Plant & Equipment – General and Administrative Overhead
IFRS	As per IAS 16, para. 19 Examples of costs that are not costs of an item of property, plant and equipment are: (a) costs of opening a new facility; (b) costs of introducing a new product or service (including costs of advertising and promotional activities); (c) costs of conducting business in a new location or with a new class of customer (including costs of staff training); and (d) administration and other general overhead costs.
MH Current	To date, Manitoba Hydro (Electric operations) has reduced administrative overhead costs allocated to capital under CGAAP in the amount of approximately $62 annually. These changes were made to better align Manitoba Hydro's capitalization practices with those of other utilities and were agreed to by the PUB in Order 43/13 page 15 which states, "In the Board's view, Manitoba Hydro's proposed accounting changes are appropriate for the test years."
MH Proposed	Upon transition to IFRS, Manitoba Hydro (Electric operations) expects to eliminate an additional $55 million of annual administrative overheads from capitalization as such charges do not meet the IFRS criteria for inclusion in the cost of self constructed capital assets.
OEB	The OEB will require utilities to adhere to IFRS capitalization accounting requirements for rate making and regulatory reporting purposes after the date of adoption of IFRS. Utilities will be required to file a copy of its capitalization policy, identifying any updates to the policy, as part of its first rate filing after IFRS adoption. Revenue requirement impacts of any change in capitalization policy must be specifically and separately identified.
AUC	Utilities shall adhere to the IFRS requirements for capitalization of costs that are not directly attributable to an asset. Any financial difference that arises as a result of the adoption of the IFRS requirements is to be identified in a utility's first IFRS-compliant GRA/GTA, and the utility shall also propose in that rate application the method for settling the difference. In addition, the utility will file a copy of its updated capitalization policy as a part of its first IFRS-compliant GRA/GTA.

	Property Plant & Equipment - Borrowing Costs
IFRS	As per IAS 23, para. 1 "Borrowing costs that are directly attributable to the acquisition, construction, or production of a qualifying asset form part of the cost of that asset. Other borrowing costs are recognized as an expense."
MH Current	MH's interest capitalization rate consists of the weighted average debt rate for all debt outstanding for the period, including anticipated borrowings in the upcoming fiscal year. Where debt is designated to finance a particular capital project, MH will capitalize interest to the asset based on the interest rate from that designated debt issue.
MH Proposed	No future changes are proposed upon transition to IFRS
OEB	The OEB will continue to publish interest rates for CWIP as it does now. Where incurred debt is acquired on an arms length basis, the actual borrowing cost should be used for determining the amount of carrying charges to be capitalized to CWIP for rate making during the period, in accordance with IFRS. Where incurred debt is not acquired on an arm's length basis, the actual borrowing cost may be used for rate making, provided that the interest rate is no greater than the OEB's published rates. Otherwise, the applicant should use the OEB's published rates.
AUC	Subject to subsection (ii), utilities shall maintain the Existing Accounting Practice of including the debt and equity components of AFUDC when accounting for construction work in progress and plant in service. (ii) Utilities may submit an application to the AUC requesting approval to make their regulatory accounting practice the same as the practice under IFRS.

	Property Plant & Equipment - Customer Contributions
IFRS	Under IFRS, customer contributions are to be recognized as revenue; either immediately or over some future period of time. The customer contribution is recognized as revenue based upon the performance obligations of the underlying arrangement.
MH Current	Currently, non-refundable contributions in aid of construction are separately recorded on the balance sheet and amortized to income on a straight-line basis as a reduction to depreciation over the life of the related item of PP&E.
MH Proposed	Customer contributions will be recognized as deferred revenue upon transition to IFRS where the revenue will be recognized over the life of the related plant asset. This will result in little or no impact to net income. However, classification on the income statement will change as the amortization of the contribution that was previously recognized as an offset in depreciation expense will now be recognized as other revenue.
OEB	For regulatory reporting and rate making purposes, customer contributions will be treated as deferred revenue to be included as an offset to rate base and amortized to income over the life of the facilities to which they relate. Distributors should confirm in the introduction to their first rates application after the IFRS transition that the amortization period is being adjusted on an ongoing basis.
AUC	Utilities shall maintain the Existing Accounting Practice of recognizing customer contributions in their property, plant & equipment accounts and including the amortization as an offset to depreciation.

	Property Plant & Equipment - Asset Reclassifications from PPE to Intangible Assets
IFRS	As per IAS 38, para. 8 "An intangible asset is an identifiable non-monetary asset without physical substance." As per IAS 38, para. 4. "Some intangible assets may be contained in or on a physical substance such as a compact disc (in the case of computer software), legal documentation (in the case of a licence or patent) or film. In determining whether an asset that incorporates both intangible and tangible elements should be treated under IAS16 Property, Plant and Equipment or as an intangible asset under this Standard, an entity uses judgment to assess which element is more significant."
MH Current	Upon adoption of CICA section 3064 for its March 2010 year end, MH reclassified (April 1, 2008 balances, net of accumulated amortization) $103 million of Computer Software development and $37 million of Easements from Property, Plant & Equipment to a separate category titled Goodwill and Intangible Assets.
MH Proposed	No future changes are proposed upon transition to IFRS.
OEB	Where IFRS requires certain assets to be recorded as intangible assets that were previously included in PP&E (e.g. computer software and land rights), utilities shall include such intangible assets in rate base and the amortization expense in depreciation expense for determining revenue requirement. This reclassification is also necessary to preserve continuity of the rate base.
AUC	Utilities shall maintain the Existing Accounting Practice of recognizing intangible assets as part of their property, plant & equipment accounts.

	Property Plant & Equipment - Asset Retirement Obligations
IFRS	As per IAS 16, para. 16 "The cost of an item of property, plant and equipment comprises:,… (c) the initial estimate of the costs of dismantling and removing the item and restoring the site on which it is located, the obligation for which an entity incurs either when the item is acquired or as a consequence of having used the item during a particular period for purposes other than to produce inventories during that period." As per IAS37 para. 10, "A constructive obligation is an obligation that derives from an entity's actions where: (a) by an established pattern of past practice, published policies or a sufficiently specific current statement, the entity has indicated to other parties that it will accept certain responsibilities; and (b) as a result, the entity has created a valid expectation on the part of those other parties that it will discharge those responsibilities."
MH Current	Under GAAP, MH has recognized AROs for the decommissioning of a thermal generating station and the partial decommissioning of a hydraulic generating station.
MH Proposed	MH has reviewed its circumstances under IFRS and has preliminarily concluded that no new provisions exist pertaining to constructive obligations. MH will recognize such obligations when a commitment is made to decommission an asset and significant removal and/or remediation costs are expected to be incurred
OEB	Utilities shall identify separately in their rate applications the depreciation expense associated with amortizing asset retirement costs and the accretion expense associated with the amortization of the asset retirement obligations. The OEB will assess these costs independently of other amortization costs to determine the portion, if any, of these costs that should be recovered in revenue requirement.
AUC	Subject to subsection (ii), utilities shall maintain the existing accounting practice regarding the treatment of asset retirement obligations and future removal and site restoration costs. (ii) Utilities may, by way of application to the AUC, request approval to account for asset retirement obligations and future removal and site restoration costs in accordance with IFRS.

	Property Plant & Equipment - Gains and Losses on Disposition of Assets
IFRS	As per IAS 16, para. 68 "The gain or loss arising from the derecognition of an item of property, plant and equipment shall be included in profit or loss when the item is derecognized,…. Gains shall not be classified as revenue."
MH Current	MH currently recognizes gains and losses on the retirement of plant assets in accumulated depreciation.
MH Proposed	Upon transition to IFRS, MH is planning to recognize gains and losses on asset retirements to net income as they occur. Such gains and losses are expected to be minimized upon transitioning to the Equal Life Group method of depreciation upon transition to IFRS.
OEB	Where a utility for financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings the utility shall reclassify such gains and losses as depreciation expense and disclose the amount separately. Where a utility for financial reporting purposes under IFRS has reported a gain or loss on disposition of individual assets, such amounts should be identified separately in rate filings for review by the OEB.
AUC	Utilities shall maintain the existing accounting practice of recording gains and losses upon retirement or disposal of assets. Utilities shall identify and record any difference in accounting between the IFRS reporting requirements and these regulatory reporting requirements in a separate subsidiary accumulated depreciation account.

	Property Plant & Equipment - Treatment of Asset Impairment
IFRS	As per IAS 36, para 9. "An entity shall assess at the end of each reporting period whether there is any indication that an asset may be impaired. If any such indication exists, the entity shall estimate the recoverable amount of the asset. para. 60, "An impairment loss shall be recognised immediately in profit or loss, unless the asset is carried at revalued amount in accordance with another Standard."
MH Current	Under CGAAP, long-lived assets should be tested whenever events or changes in circumstances indicate their carrying amount may not be recoverable. MH performs an annual impairment test on its goodwill balances which have not indicated any impairment to date.
MH Proposed	MH does not anticipate any substantial changes to its annual impairment testing requirements.
OEB	Where for financial reporting purposes under IFRS a utility has recorded an asset impairment loss, for rate application filings such losses shall be reclassified to PP&E and identified separately to allow consideration of whether and how such amounts are to be reflected in rates.
AUC	Utilities shall maintain the existing accounting practice of having no impairment (or impairment reversal) charges included when providing or reporting financial information to the AUC.

	Depreciation
IFRS	As per IAS 16, para. 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." para. 60, "The depreciation method used shall reflect the pattern in which the asset's future economic benefits are expected to be consumed by the entity."
MH Current	MH currently depreciates its PP&E component groupings on a straight-line remaining-life basis.
MH Proposed	MH has established new depreciation component groupings as necessary to comply with IFRS requirements. New depreciation rates utilizing the Equal Life Group method of depreciation have been established for implementation upon transition to IFRS. In conjunction with this, Manitoba Hydro has chosen to eliminate its provision in depreciation rates for asset removal costs in order to mitigate the impacts of other accounting changes to a net reduction in revenue requirement. This is consistent with the PUB findings as per page 18 of Order 43/13, "*The Board accepts Manitoba Hydro's position that net salvage should be removed from depreciation when International Financial Reporting Standards are implemented rather than during the test years.*"
OEB	Utilities should continue to use the straight line method of depreciation for regulatory accounting purposes. The OEB engaged Kinectrics Inc. to perform a joint depreciation study for electricity distributors to assist them in making the transition from GAAP to IFRS and to assist them with the determination of suitable asset total service lives for assets commonly used in the distribution of electricity in Ontario. Distributors are required to assess whether the service lives as set out in the Kinectrics report are applicable to their own utility. Where applicable, utilities may make changes to their depreciation rates consistent with the recommendations of the Kinectrics report.
AUC	(i) Depreciation Rates A. Subject to subsection (B), utilities shall continue to use the depreciation rates utilized under the existing accounting practice. B. If the adoption of the IFRS requirements for external financial reporting results in depreciation rates that differ from existing accounting practice or results in a difference in the timing of commencement of depreciation, or both, then a utility may, by way of application to the AUC, request approval to account for regulatory depreciation in accordance with IFRS. (iii) Componentization A. Subject to subsection (B), with respect to componentization, utilities shall record assets at the level of detail being reported under the Existing Accounting Practice. B. If the adoption of IFRS requirements for external financial reporting results in a different level of componentization, then a utility may, by way of application to the AUC, request approval to account for regulatory componentization in accordance with IFRS.

	Financial Reporting
IFRS	As per IAS 1, para. 15, "Financial statements shall present fairly the financial position, financial performance and cash flows of an entity. Fair presentation requires the faithful representation of the effects of transactions, other events and conditions in accordance with the definitions and recognition criteria for assets, liabilities, income and expenses set out in the Framework. The application of IFRSs, with additional disclosure when necessary, is presumed to result in financial statements that achieve a fair presentation." para. 16 "An entity whose financial statements comply with IFRSs shall make an explicit and unreserved statement of such compliance in the notes. An entity shall not describe financial statements as complying with IFRSs unless they comply with all the requirements of IFRSs."
MH Current	Given that the AcSB permitted rate-regulated entities to defer transition to IFRS, MH's audited financial statements will be presented in accordance CGAAP for fiscal year 2014/15.
MH Proposed	MH's audited financial statements will be presented in accordance with IFRS commencing in its fiscal 2015/16 fiscal year and forward. IFRS based comparatives will be issued for the 2014/15 fiscal year.
OEB	The OEB does not have the authority to determine a utilities form of financial reporting (i.e. IFRS or US GAAP) for external financial reporting purposes.
AUC	The AUC does not have the authority to determine a utilities form of financial reporting (i.e. IFRS or US GAAP) for external financial reporting purposes.

	Application Reporting
IFRS	IFRS does not include a standard that applies to the rate application reporting of rate-regulated utilities.
MH Current	MH's 2015/16 and 2016/17 GRA is prepared on the basis that MH would transition to IFRS in its 2015/16 fiscal year. As such the 2014/15 filing requirements were based on CGAAP and the 2015/16 filing requirements were based on IFRS as per IFF 14.
MH Proposed	MH is proposing that upon transition to IFRS that financial and regulatory reporting will be aligned.
OEB	For utilities adopting IFRS, the OEB's requires the historical year (1 year prior to bridge reporting year) to be presented in accordance with CGAAP, the Bridge year to be presented in accordance with CGAAP plus adjustments for rate setting purposes, for the test year in accordance with rate setting purposes.
AUC	Please see Attachment 3 to this response for the AUC's IFRS application reporting requirements per AUC Rule 026. It is MH's understanding, that utilities that use a form of financial reporting that is different than CGAAP, must file rate applications in accordance with Rule 026 and where applicable, seek approval for regulatory deferral accounts for differences between financial reporting and regulatory reporting.

The following list of documents were the primary documents referenced by Manitoba Hydro in compiling the information for this response.

Ontario jurisdiction:

- April 30, 2012 OEB letter Impact on the Decision to defer the Mandatory Date for the Implementation of International Financial reporting Standards to January 1, 2013 by the Canadian Accounting Standards Board;
- July 8, 2010 Asset Depreciation Study for the Ontario Energy Board (Kinectrics Report); and
- July 28, 2009 OEB report "EB-2008-0408, Report of the Board, Transition to International Financial Reporting Standards" which was updated for the February 24, 2010 letter issued by the OEB re: Accounting for Overhead Costs Associated with Capital Work (This letter confirmed that the OEB will require utilities to adhere to IFRS overhead capitalization requirements for rate making and regulatory reporting purposes after the date of adoption of IFRS) and amendments dated November 8, 2010 and March 15, 2011.
- Ontario Securities Commission – (July 21, 2011) In the Matter of Exemptive Relief Applications in Multiple Jurisdictions and in the Matter of Hydro One Inc.
- Ontario Securities Commission – (July 21, 2011) In the Matter of the Process for Exemptive Relief Applications in Multiple Jurisdictions and in the Matter of Ontario Power Generation Inc.
- Ontario Power Generation Inc. 2013 Financial Results - Management Discussion and Analysis
- Hydro One Annual Report 2012 – Management Discussion and Analysis

Alberta jurisdiction:

- May 19, 2009 AUC – Rule 026 – Regulatory Account Procedures Pertaining to the Implementation of the International Financial Reporting Standards, amended November 13, 2013.
- Fortis Alberta Annual Report December 31, 2011, Management Discussion and Analysis

Quebec jurisdiction:

- Hydro Quebec, Annual Report December 31, 2014 Note 1 to the Financial Statements
- R-3905-2014 Response D'Hydro-Quebec Distribution A La Demande De resnseignements No 4 De La Regie

Alberta Utility Commission

Fiscal year	Year filed	Actual / forecast	Accounting/reporting standard to use
2013	2014	Actual	For utilities that have adopted IFRS effective January 1, 2013 – this rule is to be followed for regulatory filings with the AUC, complete with 2012 comparatives prepared using this rule; IFRS is to be used for financial statements, including 2012 comparatives prepared using IFRS. For utilities adopting IFRS effective January 1, 2014, or January 1, 2015 – existing accounting practice is to be followed for regulatory filings with the AUC; existing Canadian GAAP is to be used for financial statements.
2014	2015	Actual	For utilities that have adopted IFRS effective January 1, 2013 – this rule is to be followed for regulatory filings with the AUC, complete with 2013 comparatives prepared using this rule; IFRS is to be used for financial statements, including 2013 comparatives prepared using IFRS. For utilities adopting IFRS effective January 1, 2014 – this rule is to be followed for regulatory filings with the AUC, complete with 2013 comparatives prepared using this rule; IFRS is to be used for financial statements, including 2013 comparatives prepared using IFRS. For utilities adopting IFRS effective January 1, 2015 – existing accounting practice is to be followed for regulatory filings with the AUC; existing Canadian GAAP is to be used for financial statements.
2015 and beyond	2016 and beyond	Actual	This rule is to be followed for regulatory filings with the AUC, complete with prior year comparatives prepared using this rule; IFRS is to be followed for financial statements, including prior year comparatives prepared using IFRS.
2014 (first year in test period) and beyond	2013 and beyond	Forecast	For utilities that have adopted IFRS effective January 1, 2013 – this rule is to be used for forecasts filed with the AUC. For utilities adopting IFRS effective January 1, 2014 – this rule is to be used for forecasts filed with the AUC. For utilities adopting IFRS effective January 1, 2015 – existing accounting practice is to be used for the 2014 forecast year; this rule is to be used for the 2015 and beyond forecast years.
2015 and beyond	2013 and beyond	Forecast	This rule is to be used for forecasts filed with the AUC.

Section:	Tab 5: Appendix 5.6 Attachment 4	Page No.:	PUB/MH I-42 b
Topic:	Financial Results and Forecast		
Subtopic:	Depreciation Expense		
Issue:	Changes in 2014 Depreciation Study		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide a list of the Canadian electric utilities in other Canadian jurisdictions currently seeking approval for using the ELG procedure.

b) Please indicate the depreciation practices of Ontario-based electric utilities, specifically whether they use ASL or ELG and the extent of componentization for ASL-based utilities.

c) Please file the Gannett Fleming Depreciation Study for Ontario Power Generation Inc. (OPG), including the listing of depreciation accounts.

d) Please describe the process followed by OPG to determine that additional componentization was not required for IFRS compliance.

e) Please indicate whether MH has undertaken the same level of investigation as part of its IFRS conversion activities as OPG. If not, please elaborate.

RATIONALE FOR QUESTION:

To understand the prevalence of the ASL and ELG approaches in Canadian regulated electric utilities.

RESPONSE:

a) Manitoba Hydro and Gannet Fleming are not aware of Canadian electric utilities in other Canadian jurisdictions currently seeking approval to use the ELG procedure. Notably, many utilities applying the ASL method are reporting under US GAAP which has componentization requirements similar to CGAAP.

Please see the response to PUB/MH-I-42b for a listing of North American utilities (including the Regulatory jurisdiction) which have received approval for the use of Equal Life Group (ELG) procedure for rate-setting purpose. Specifically, Gannet Fleming ULC is aware that the following Canadian electric utilities use the ELG procedure:

ATCO Electric
ATCO Gas
Enmax Power Corporation
FortisAlberta Utilities, Inc.
Newfoundland Power Limited
Northland Utilities (NWT) Limited
Northland Utilities (Yellowknife) Limited
Nova Scotia Power, Inc.

b) Manitoba Hydro and Gannett Fleming are aware of the depreciation practices of Ontario Power Generation (OPG) and Hydro One. OPG follows US GAAP using the ASL method and, as demonstrated in the depreciation study included in the response to part c, OPG is more componentized than Manitoba Hydro. In addition, Hydro One follows US GAAP using a vintage based procedure which requires an additional layer of componentization for each installation year within each component.

Manitoba Hydro and Gannett Fleming are not in a position to know the depreciation practices of other Ontario-based electric utilities, specifically whether they use ASL or ELG and the extent of componentization for ASL-based utilities.

c) Please see the attachment to this response for the latest (2013) Gannett Fleming Depreciation Study for Ontario Power Generation Inc.

d) Manitoba Hydro and Gannett Fleming are not aware of the process followed by OPG to determine whether or not additional componentization was required for IFRS compliance. At the time of their last (2013) depreciation study, OPG filed the study consistent with the requirements of US GAAP; compliance with IFRS was not considered as part of that depreciation study.

e) Please see the response to part (d) of this question. Manitoba Hydro's level of investigation into ensuring its asset components are compliant with IFRS has appropriately focussed on assessing its own operations (both past and future) and accounting records, as well as enlisting the services of a depreciation expert from Gannett Fleming to assist with developing the necessary components for compliance with IFRS. Manitoba Hydro also received assistance from KPMG and Ernst & Young with respect to confirming that IFRS has stricter rules with respect to componentization for determining depreciation.

Large utilities are complex organizations that evolve based on the influence of economic, demographic, regulatory, geographic and political impacts specific to their jurisdiction. As such, numerous differences exist between Canadian utilities with respect to the nature, age and condition of their assets, the state of their historical PP&E accounting records, and the influence their respective regulators have had over their accounting/regulatory practices. Although some common depreciation practices exist across the Country, such as the use of the ASL method, the application of these methods can vary across utilities depending on upon their degree of componentization and the how the accounting records are maintained within each component. Generic guidance or studies for componentization and depreciation methods as developed for utilities in one jurisdiction would likely not reflect the circumstances of a particular utility in a different jurisdiction.

Where information is available, Manitoba Hydro has considered the IFRS related changes being made by other utilities in formulating its own policies (e.g. reductions in overhead capitalized). Notably, very few Canadian electric-based utilities have transitioned to IFRS so there is very little audited and confirmed information available from which to compare to. In consideration of Manitoba Hydro's specific circumstances, the adoption of the ELG method of depreciation is the most efficient and best approach for Manitoba Hydro to comply with IFRS. As discussed in Tab 2, page 46, the adoption of the ELG method, in combination with the other accounting changes being made by Manitoba Hydro, including the removal of negative salvage from depreciation rates, is not driving the need for rate increases and as such, there is no benefit to customers of continuing with CGAAP accounting policies for rate-setting purposes upon transition to IFRS.

ONTARIO POWER GENERATION INC.

TORONTO, ONTARIO

ASSESSMENT OF REGULATED ASSET DEPRECIATION RATES AND GENERATING STATION LIVES NOVEMBER 2013

Gannett Fleming

Excellence Delivered ***As Promised***

November 29, 2013

Ontario Power Generation Inc.
700 University Avenue
Toronto, Ontario
M5G1X6

Attention:
Mr. David Bell
Senior Manager, Accounting and Reporting
Ontario Power Generation Inc.

Pursuant to your request, we have conducted a review and assessment of the Regulated Asset Depreciation Rates and Generating Station Lives of Ontario Power Generation Inc. ("OPG"). Our report presents a description of the methods used in the estimation of service life and our recommendations for average service life estimates.

We gratefully acknowledge the assistance of OPG personnel in the completion of the review.

Respectfully submitted,
GANNETT FLEMING CANADA ULC.

LARRY E. KENNEDY
VICE PRESIDENT

LEK/hac
Project: 057677

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PART I. INTRODUCTION

ONTARIO POWER GENERATION

ASSESSMENT OF REGULATED ASSET DEPRECIATION RATES AND GENERATING STATION LIVES

PART I. INTRODUCTION

SCOPE

This report sets forth the results of the Gannett Fleming Canada ULC (“Gannett Fleming”) review of the Ontario Power Generation Inc. (“OPG” or “the Company”) average service life estimates based on December 31, 2012 asset values and for Niagara Tunnel placed in-service in 2013. The average service life estimates recommended in this report are considered in OPG’s depreciation review process in establishing the asset depreciation rates and generating station lives for the Property, Plant and Equipment (“PP&E”) of OPG’s prescribed facilities, including directly assigned corporate PP&E balances. As the depreciation and amortization expense is calculated for revenue requirement purposes, the assets for which average service lives were analyzed include intangible assets.

The facilities for which average service lives were analyzed consist of two nuclear generating stations (Pickering and Darlington) and 54 hydroelectric stations, including six stations (the “previously regulated hydroelectric facilities”) that were prescribed by *Ontario Regulation 53/05* under the *Ontario Energy Board Act, 1998* effective 2005 (Sir Adam Beck I, II and the Pump Generating Station; DeCew Falls I and II; R.H. Saunders) and 48 stations (the “newly regulated hydroelectric facilities”) that are proposed to be prescribed, as announced by the Government of Ontario in a proposed amendment to *Ontario Regulation 53/05*.[1]

Given the similarity of the plant making up both the previously and newly regulated hydroelectric facilities, the assets of both groups of facilities are categorized by OPG using the same asset classes, with the same average service lives. As part of this study, Gannett Fleming specifically reviewed the operating considerations and typical station configurations of the newly regulated hydroelectric facilities in order to determine if this approach is reasonable, or if there is a need for additional componentization or changes to average service lives specific to these facilities. This review included site tours of 16 newly regulated facilities and operational staff discussions.

REPORT STRUCTURE

Part I, Introduction, contains statements with respect to the scope and plan of the report and the basis of the study. Part II, Methods Used in the Estimation of Average Service Life, presents the methods used in the estimation of average service lives. Part III, Results of Study, presents a summary of the service life estimates and the comparable peer data used in the development of the average service life estimates. Schedule 1A of this report summarize the average service life estimates for the accounts making up the previously and newly regulated hydroelectric facilities. Schedule 1B of this report summarizes the average service life estimates for all

[1] Notice of proposed amendment can be found in OPG's application to the Ontario Energy Board for new payment amounts under EB-2013-0321 Ex. A1-6-1, Attachment 3.

accounts of the prescribed nuclear assets and also separates the nuclear Asset Retirement Costs ("ARC"), which are depreciated over station lives.

BASIS OF THE STUDY

Background. In March 2007, Gannett Fleming submitted a report titled "Review of the Ontario Power Generation Inc. Depreciation Review Process" (the "2007 Report"). The 2007 Report presented a summary of the findings of an independent review of the processes, procedures and methods used by OPG to review its depreciation expense. The 2007 Report indicated that "Gannett Fleming has found that the processes, procedures and methods followed by Ontario Power Generation Inc. adequately meet regulatory objectives regarding depreciation generally accepted by Canadian regulatory authorities."[2] Additionally, Gannett Fleming found that "OPG's current Depreciation Review Process results in the depreciation expense component of the revenue requirement that reasonably and appropriately reflects the consumption of the average service life of OPG's regulated assets. Gannett Fleming also views that, overall, the DRC process is adequate in meeting the generally accepted regulatory objectives regarding depreciation for regulated North American utilities."[3] Overall, the 2007 Report concluded that the procedural foundation upon which OPG's Depreciation Review Committee ("DRC") has developed average service life estimates is robust and appropriate. The 2007 Report contributed, in part, to the Ontario Energy Board ("OEB") Decision EB-2007-0905 finding that the approach employed by OPG in the development of its depreciation expenses is reasonable.

[2] Cover Letter to the 2007 Report.
[3] 2007 Report, page III-2.

In 2011, Gannett Fleming was retained by OPG to complete a comprehensive assessment of the asset depreciation rates and generating station lives of OPG's regulated assets as of December 31, 2010. As noted in the report titled "Assessment of Regulated Asset Depreciation Rates and Generating Station Lives" dated December 16, 2011 (the "2011 Depreciation Study"), the DRC had continued to follow the methods as outlined in the 2007 Report in the four years since the issuance of that report. Furthermore, Gannett Fleming found that OPG had modified and adapted its processes to address the key recommendations in the 2007 Report. As such, Gannett Fleming viewed that the then currently approved average service life estimates continued to be based on a procedurally sound and reasonable DRC process. In light of this, Gannett Fleming found much of the work prepared by the DRC over the preceding several years to be a reliable information source in the course of conducting the 2011 Depreciation Study. The 2011 Depreciation Study recommended the continuation of the currently approved average service life estimates for all plant accounts for OPG's regulated assets, with three modifications to the average service life estimates to the hydroelectric accounts, including the creation of a new plant account for security systems. OPG implemented these modifications for all of its hydroelectric operations effective January 1, 2012.

The 2011 Depreciation Study also recommended the continuation of the then current life span dates for the regulated stations, including the Pickering A and Pickering B nuclear units (now more generally described as Pickering to reflect the consolidation of the units into a single station), pending the technical results of a pressure tube study. Specifically, Gannett Fleming noted the following: "Gannett Fleming believes that until the review of the Pickering B plant is completed it is premature to adjust the life span date of Pickering A from the current date of December 31, 2021. Gannett Fleming also believes that the use of a life span of September 30, 2014 for Pickering B is appropriate until such time as reviews to determine the economic feasibility of a major pressure tube program are completed, which Gannett Fleming understands is expected in 2012. In the circumstance that the assessment of the condition of the Pickering pressure tubes results in a decision that the Pickering plant cannot continue operations, future depreciation reviews may be required to adjust the life span date of the Pickering A units."[4]

As anticipated in the 2011 Depreciation Study, the results of the work program related to the Pickering B (now known as Pickering Units 5 through 8) pressure tubes confirmed in 2012 that these units could operate beyond September 30, 2014. In addition, the Niagara Tunnel, which represents a significant new addition to the PP&E of OPG's regulated assets, was placed in-service in 2013, and 48 additional OPG hydroelectric facilities are proposed to become subject to OEB regulation. In light of these developments, OPG issued a Request for Proposal in 2013 for a new independent depreciation study. Gannett Fleming was retained to provide an independent professional opinion regarding the average service life estimates used by OPG for the previously and newly regulated assets, leading to the recommendations and conclusions as contained in this report. Gannett Fleming used a similar approach to the 2011 Depreciation Study in arriving at these recommendations and conclusions.

The DRC has continued to follow the methods outlined in the 2007 Report,

[4] 2011 Depreciation Study, page II-12.

having modified and adapted its processes to address key recommendations in that report. As such, the currently approved average service life estimates, as modified by the results of the 2011 Depreciation Study, continue to be based on a procedurally sound and reasonable DRC process. Given this previously-reviewed DRC process, the prior Gannett Fleming findings regarding this process, and the review of the DRC work by Gannett Fleming as part of the 2011 Depreciation Study, Gannett Fleming, to a large extent, continues to find the work prepared over the past several years by the DRC to be a reliable information source. While the 2007 Report and the 2011 Depreciation Study were focused on the prescribed facilities, OPG's internal DRC review process applies to all of OPG's hydroelectric facilities, including the newly regulated hydroelectric plants. In light of this and given the similarity of plant assets and asset management programs across OPG's hydroelectric fleet, Gannett Fleming also finds the DRC work to be, to a large extent, a reliable source of information for the newly regulated hydroelectric facilities.

With the exception of minor fixed assets, which represent approximately 2% of OPG's total regulated investment excluding ARC, OPG continues to depreciate its regulated assets using a straight line method of depreciation, with the depreciation rates being calculated based on the Average Life Group – Whole Life Procedure. The Average Life Group – Whole Life procedure has been used by OPG for a number of years and has previously been approved by the OEB.

Service Life Estimates. The service life estimates presented herein are based on commonly accepted methods and procedures for determining average service life estimates for electric utility plant, and consideration of information obtained about condition assessments through discussion with OPG operating staff and site tours. The service life estimates were based on in-service asset values through December 31, 2012 (with the exception of the Niagara Tunnel which was placed in-service in 2013), a review of the Company's practices and outlook as they relate to plant operation and retirement, and the service life estimates for other electric generation companies.

The average service life estimates for each depreciable group were reviewed based on the professional judgment of Gannett Fleming. In reviewing the average service lives, Gannett Fleming gave consideration to the average service lives currently approved for use by OPG; the results of the 2011 Depreciation Study; the approved service life estimates for a peer group of electric generation companies; the experience of internal OPG operating and management staff; assessment of asset conditions; and the experience of Gannett Fleming in selecting average service lives for similar plant. Gannett Fleming's review of the average service lives for the Niagara Tunnel is discussed specifically in Part II of this report.

Depreciation Policy. In the review of OPG's plant account structure, Gannett Fleming considered the expectation of the diversity of asset retirement ages within each account in the development of the average service life estimate for each account. The use of the Average Life Group - Whole Life Procedure applies the same annual accrual rate to all vintages of plant, which is calculated by dividing 100% by the average service life estimate. As such, a common life estimate is applied to each of the asset vintages, and each of the assets within each vintage. This procedure is widely used by a number of regulated electric utilities throughout North America, and results in a reasonable recovery of capital investment.

Depreciation related to the nuclear asset classes continues to be based on the lesser of the generation station life or asset class life. Hydroelectric generating stations' lives, including those of the newly regulated hydroelectric stations, are considered to be limited by the service lives of the dams; however, since the dams have service lives that exceed those of most other asset classes, Gannett Fleming is of the view that they are not a significant limiting factor at this time.

As discussed later in this report, based on its review, Gannett Fleming has recommended that two new hydroelectric plant accounts and two new nuclear plant accounts be created in order to separate certain assets currently recorded in other accounts. Gannett Fleming also understands that, for ease of future average service life reviews, the DRC is considering a recommendation for a disaggregation of Account 15340000 – Nuclear Process Systems into separate, new plant accounts for major types of systems. The new accounts would have the same average service life of 55 years as Account 15340000. Gannett Fleming agrees with this approach, as it would facilitate future service life reviews.

RECOMMENDATIONS

The average service life estimates set forth herein apply specifically to the PP&E (including intangible assets) of OPG's previously and newly regulated hydroelectric facilities and prescribed nuclear facilities, including directly assigned corporate PP&E, as of December 31, 2012 and the Niagara Tunnel placed in-service in 2013. The average service life recommendations contained in this report should be applied to all assets within each group of assets. As described in the Results section of this report, Gannett Fleming is recommending six changes to the average service life estimates, as follows:

- Account 10318000 – Hydroelectric – Gates, Stoplogs and Operating Mechanisms – Change average service life estimate from the currently approved 50 years to 55 years;
- New Account – Hydroelectric – Roofing – Create a new plant account with an average service life estimate of 30 years;
- New Account – Hydroelectric – Fencing – Create a new plant account with an average service life estimate of 25 years;
- New Account – Nuclear – Roofing – Create a new plant account with an average service life estimate of 25 years;
- New Account – Nuclear – Large Circulating Water Motors (greater than 200Hp) – Create a new plant account with an average service life estimate of 30 years; and
- Reclassification of assets for nuclear turbine generator controls from existing Account 15411100 – Turbines and Auxiliaries with a 55-year average service life to existing Account 15600000 – Nuclear – Instrumentation and Control with a 15-year average service life.

Gannett Fleming is also of the view that, as recommended by the DRC in 2012, a new hydroelectric plant account with an average service life estimate of 90 years should be established for the tunnel lining of the new Niagara Tunnel.

Continued surveillance and periodic revisions are required to maintain use of appropriate average service lives and depreciation rates. Each account should be subjected to a complete depreciation study which re-evaluates its average service life estimates periodically. Gannett Fleming notes that the practice of OPG to review its various asset accounts and depreciation service lives over an approximate five-year cycle meets this common depreciation practice.

PART II. METHODS USED IN THE ESTIMATION OF AVERAGE SERVICE LIFE

PART II. METHODS USED IN THE ESTIMATION OF AVERAGE SERVICE LIFE

DEPRECIATION

Depreciation, in public utility regulation, is the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric generation plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, deterioration, action of the elements, inadequacy and obsolescence.

Depreciation, as used in accounting, is a method of distributing fixed capital costs, less net salvage, over a period of time by allocating annual amounts to expense. Each annual amount of such depreciation expense is part of that year's total cost of providing utility service. Normally, the period of time over which the fixed capital cost is allocated to the cost of service is equal to the period of time over which an item renders service, that is, the item's service life. The most prevalent method of allocation is to distribute an equal amount of cost to each year of service life. This method is known as the Straight Line method of depreciation.

As described in earlier sections of this report, the recommendations of this report are to continue to incorporate the depreciation practices historically used at OPG, namely that the depreciation expense be calculated in accordance with the Straight Line method of depreciation, incorporating the Average Life Group - Whole Life procedure in the calculation of the depreciation rate. The calculation of annual depreciation expense based on the Straight Line - Average Life Group - Whole Life procedure requires the estimation of average life as discussed in the sections that follow.

AVERAGE SERVICE LIFE

The use of an average service life for property groups that include large numbers of similar assets implies that the various units in the group have different lives. Thus, the average life may be obtained by determining the separate lives of each of the units, or by constructing a life estimate that considers the retirements of units which survive at successive ages. The average service life estimates reviewed by Gannett Fleming were based on judgment which considered a number of factors, including:

- Understanding of the processes used in the development of the currently used average service life estimates through the completion of a prior review of the DRC process filed in EB-2007-0905, and through the completion of the 2011 Depreciation Study;
- Understanding of the assets currently in service through discussions with company staff, including representatives of the nuclear and hydroelectric generation operating units;
- Physical site tours of nuclear and newly regulated hydroelectric generation sites;
- Review of current accounting practices and procedures applied and their consistency with those in place during the review submitted in EB-2007-0905 and those reflected in the 2011 Depreciation Study;
- Review of analyses provided to DRC;
- Average service life estimates from other peer electric generation companies; and,
- The general experience and professional judgment of Gannett Fleming.

Prior Assignments and Review of the DRC Process. Gannett Fleming had been previously retained in 2007 to review the practices and procedures used by the DRC in the completion of prior depreciation studies, and, in 2011, for the completion of a full depreciation study. The 2007 review resulted in a report of the findings of Gannett Fleming which were submitted to the management of OPG in 2007. The 2011 Depreciation Study resulted in a report dated December 16, 2011, which was submitted to management of OPG in 2011 and, in 2013, filed by OPG in OEB proceeding EB-2013-0321. These prior reviews provided Gannett Fleming with an understanding of the processes used by OPG in the determination of average service life estimates, a general understanding of the type of generation plant in service at OPG, and an understanding of the regulatory oversight of the Ontario Energy Board.

Operating Discussions and Site Tours. Discussions with operating representatives and the physical site tours undertaken by Gannett Fleming provided Gannett Fleming with an understanding of the type of assets in service for both nuclear and hydroelectric service. The site tours provide Gannett Fleming with the necessary background to make an assessment of the physical installations of the OPG plant, and to understand the type of plant in service and the operating conditions of the facilities. The operating interviews are undertaken to understand the historic operating conditions that have led to retirement of plant in the past and to understand the current condition of the assets which may impact future retirement plans. The operating interviews were conducted both during the Gannett Fleming tours of the physical facilities and immediately following the tours, and again after Gannett Fleming completed an initial analysis of the average service life expectations.

In conducting the 2011 Depreciation Study, Gannett Fleming toured the following generation sites:

- R.H. Saunders Hydroelectric Generating Station;
- Sir Adam Beck I Hydroelectric Generating Station;
- Sir Adam Beck II Hydroelectric Generating Station; and
- Darlington Nuclear Generating Station.

The scope of this report includes the review of the newly regulated hydroelectric generation plants. In order to gain a better understanding of these assets and as part of the assessment of nuclear assets, Gannett Fleming toured the generation plants listed below in the course of this assignment. Gannett Fleming toured a total of 16 newly regulated hydroelectric facilities, representing a range of different types and sizes of the facilities.

- Chats Falls Hydroelectric Generating Station;
- Arnprior Hydroelectric Generating Station;
- Stewartville Hydroelectric Generating Station;
- Calabogie Hydroelectric Generating Station;
- Barrett Chute Hydroelectric Generating Station;
- Chenaux Hydroelectric Generating Station;
- Des Joachims Hydroelectric Generating Station;
- Otto Holden Hydroelectric Generating Station;

- Bingham Chutte Hydroelectric Generating Station;
- Big Chute Hydroelectric Generating Station;
- Ragged Rapids Hydroelectric Generating Station;
- Hanna Chute Hydroelectric Generating Station;
- South Falls Hydroelectric Generating Station;
- Elliot Chute Hydroelectric Generating Station;
- Tretheway Falls Hydroelectric Generating Station;
- Big Eddy Hydroelectric Generating Station;
- Darlington Nuclear Generating Station; and
- Pickering Nuclear Generating Station.

Tours of the above generating stations provided Gannett Fleming with the necessary background to complete this assignment. During and immediately following each of the above site tours, interviews of the operational representatives were undertaken by Gannett Fleming. These interviews were conducted at the time of the site tours and covered the following topics, including, where applicable, inquiries regarding operational or other changes since the 2011 Depreciation Study:

- Operating history of both the plant being toured and of other similar plant not toured;
- Replacement history of major plant components and review of significant retirement programs;
- General operating experience of the major plant components;
- Review of any life restricting operational issues;

- Review of any issues that have emerged during the DRC process;
- Review of changes where advancements in technology may cause changes to average service life indications; and
- Discussions of the manner in which OPG's hydroelectric plants may be different than other peer hydroelectric generation plants.

In addition, following the plant tours, discussions were conducted through a number of telephone interviews held between Gannett Fleming and operational representatives of OPG.

Review of Accounting Policies. Gannett Fleming had discussions with management representatives during prior assignments to understand OPG's depreciation and accounting policies and practices. As part of the current assignment, Gannett Fleming confirmed with management representatives whether there had been changes to these policies and practices since the 2011 Depreciation Study and whether these policies and practices are also applied to the newly regulated hydroelectric plant.

An understanding of the accounting policies is required to:

- Understand the accounting entries associated with the retirement of plant. In particular, Gannett Fleming required an understanding of the accounting entries associated with gains and losses on retirement;
- Understand any thresholds or policies with regard to capitalization of major component as compared to the replacement of minor components of plant through operating and maintenance budgets; and

- Determine if a review of the adequacy of the accumulated depreciation reserve is required.

Gannett Fleming notes that, notwithstanding OPG's of adoption of US GAAP, the current DRC and depreciation policies and practices for the previously regulated assets are the same as those reflected in the 2011 Depreciation Study. Gannett Fleming also notes that starting in 2011, all gains and losses on retirement transactions are booked by OPG for all of its assets to the income statement in the year of the retirement transaction. In this manner, the accumulated depreciation account does not include embedded gains or losses from previous retirement transactions. Gannett Fleming understands that, on an OPG-wide basis, the total cumulative undepreciated value of embedded past losses, which OPG removed from the net book value of fixed and intangible assets in 2011, is less than $1M.

Gannett Fleming also notes that any amount of cost of removal (that is not associated with the retirement of an asset for which an Asset Retirement Obligation ["ARO"] is established) is charged directly to the income statement in the year of the transaction. Both the recording of gains and losses to income and the charging of cost of removal to income is in accordance with the provisions of US GAAP. As previously noted in the 2011 Depreciation Study (page II-7), while these are not the traditional practices of regulated utilities, Gannett Fleming believes that the nature of the large plant components and small amount of retirement transactions make this policy viable and reasonable for OPG. Additionally, because the accumulated depreciation account does not include adjustments for past retirement transactions the need to test the adequacy of the accumulated depreciation accounts is eliminated.

Gannett Fleming confirmed that the same DRC and depreciation policies and practices are applied by OPG both to the previously and newly regulated hydroelectric assets.

Analysis and Results of DRC Reviews. OPG is the world's largest operator of CANada Deuterium Uranium ("CANDU") nuclear units, has some of the oldest CANDU units, and has the most extensive operational knowledge of all CANDU operators in the world. OPG is heavily involved in technical exchanges with other CANDU operators, and closely monitors equipment degradation issues in order to assess potential impacts on OPG's units. OPG is often the "lead" utility in terms of the knowledge of degradation issues, which may impact unit and component lives. In the particular circumstance of the CANDU nuclear installations, OPG internal staff is recognized as experts in the technology.

The DRC has continued to complete detailed reviews of the average service life expectations for OPG's plant accounts. The DRC's technical reviews are conducted by internal and external experts in the specific areas associated with a number of accounts. As indicated above, the OPG operational staff is considered to be the world experts in the operational aspects of the CANDU units. As part of the current assignment and the 2011 Depreciation Study, Gannett Fleming reviewed these analyses which provided a significant background on the physical condition of the assets, a meaningful history of the manner in which plant assets have provided electric generation service over the past many years, and identified major upcoming replacement or retirement programs.

Peer Analysis. In order to provide a comparison for each account grouping, Gannett Fleming selected a peer group of companies to use in the development of average service lives. The companies selected for comparison were all companies for which Gannett Fleming has recently completed depreciation studies relating to Canadian electric generation plants. As such, Gannett Fleming is able to make a meaningful comparison giving consideration to factors such as capitalization and retirement policies, maintenance practices, and general operational practices. The companies selected for comparison were:

- BC Hydro;
- Manitoba Hydro;
- New Brunswick Power;
- Newfoundland and Labrador Power Corporation (Nalcor);
- Northwest Territories Power Corporation; and
- SaskPower.

As noted in the 2011 Depreciation Study (page II-8), asset service lives for OPG's hydroelectric asset classes lend themselves to comparison with other utilities due to the similar nature of the technology used in hydroelectric energy production. This applies both to the previously and newly regulated hydroelectric assets. As such, the above utilities provided Gannett Fleming with a comparable base of average service life estimates to use in the development of the service life estimates for OPG's hydroelectric asset classes.

Professional Judgment. The use of professional judgment in the development of average service life estimates is a practice that is appropriate and has been used for many years before North American regulatory jurisdictions. When available, the use of statistical analysis of the historic retirement transactions combined with the use of professional judgment which includes the physical site inspections, review of accounting procedures and practices, use of operational staff interviews, review of prior studies, and review of the approved life estimates of peer companies, provides the most complete method of service life analysis. However, the use of professional judgment alone also provides an appropriate basis for developing average service life estimates, when appropriate factors are considered, and has been accepted as a valuable depreciation analysis tool in many North American jurisdictions.

In the specific circumstances of the OPG average service life estimation, the volume of historic retirement transactions available to be analyzed is not sufficient to undertake a detailed study of retirement history. As such, a retirement rate analysis was not completed by Gannett Fleming. However, all of the remaining life estimation tools were available and were used to develop appropriate average service life estimates.

Life Span Dates. Life expectancy of electric generation plant assets is impacted not only by physical wear and tear of the assets but also by economic factors including the feasibility of the economic replacement of major operating components or the economic viability of the plant as a whole. In circumstances where the replacement of major operating components is not economically feasible, the life of the major component can be the determining factor of the generation plant and all of the assets within the plant. As such, the remaining depreciation life of electric generation plant assets is the lesser of the physical life expectation of the asset or the period to the end of the life span of the generation plant.

The use of life span dates for determining depreciable lives for regulated electric generation plant is common throughout many North American regulatory jurisdictions. The basis for the determination of the life span date is usually based on one or more of the following:

- the physical life estimation of the major and vital components of the generating plant;
- the duration of operating licenses;
- precedent and policy of the regulatory jurisdiction;
- expiration of the supply source for which the generation plant is dependent; and
- expiration of market demand upon which the generation plant is dependent.

In prior depreciation reviews, OPG has determined a life span date for each of the prescribed nuclear plants. The life span dates have been determined through a review of the expected life of the significant components at each nuclear site. Additionally, the life span dates historically have been influenced by the period through to any required major site refurbishment, as the continued operation of the plant is dependent upon the ability to economically refurbish the plant for continued use. It is the experience of Gannett Fleming that the depreciation schedules for most North American nuclear generation plants are dependent upon appropriately developed life span dates. It continues to be the view of Gannett Fleming that the use of life span dates is appropriate for the OPG nuclear generation plants.

In the 2011 Depreciation Study, it was noted that an assessment of the condition of the Pickering Units 5 through 8 (formerly Pickering B) pressure tubes was underway at that time. In that report, Gannett Fleming noted that the use of a life span date of September 30, 2014 for Pickering Units 5 through 8 was appropriate until such time as reviews to determine the economic feasibility of a major pressure tube program are completed, which was expected to occur in 2012. It was also noted that the operation of Pickering Units 1 and 4 (formerly Pickering A) requires the joint operation of certain components of both sets of units. As such, both physical and economic considerations may result in the circumstance that should Pickering Units 5 through 8 be shut down before Pickering Units 1 and 4, there is a significant likelihood that the operation of Pickering Units 1 and 4 would not be viable following the shutdown. At that time, Gannett Fleming was of the view that until the review of pressure tubes at Pickering Units 5 through 8 was sufficiently complete, it was premature to adjust the life span date of Pickering Units 1 and 4 from the then current date of December 31, 2021.

In 2012, the DRC considered the impact of the results of the substantial completion in 2012 of the work program necessary to determine the feasibility of achieving extended service lives of the pressure tubes at Pickering. Upon receiving confirmation that the work program indicated high confidence that the operation of the pressure tubes at Pickering Units 5 through 8 could be extended, the DRC concluded that the following dates, which were reflected in materials submitted by OPG in OEB proceeding EB-2012-0002, appropriately recognize the expected average life spans of the nuclear stations, for depreciation purposes, effective December 31, 2012:

- Pickering Units 1 and 4 (formerly Pickering A) – December 31, 2020; and
- Pickering Units 5 through 8 (formerly Pickering B) – April 30, 2020.

The above station life span dates reflect the following expected life span dates for the individual Pickering units:

- Units 1, 4, 7 and 8 – Q4 2020
- Unit 5 – Q1 2020
- Unit 6 – Q2 2019

The life span dates for Pickering Units 1 and 4 were aligned with the last two units of Pickering Units 5 through 8 in recognition of the technical and economic considerations that likely would have prevailed against the operation of Units 1 and 4 in the absence of continued operation of at least two units of Pickering Units 5 through 8.

Gannett Fleming has reviewed the DRC's analysis in establishing the above station and unit life span dates and has concluded that they are reasonable for use in this study. Gannett Fleming is also of the view that the factors considered and methods used by the DRC in the assessment of life span dates remain appropriate and consistent with common regulatory practices and should continue to be used in future reviews.

As recognized in the previous DRC reviews and the 2011 Depreciation Study, a major refurbishment program is expected to be undertaken at the Darlington nuclear site. This continues to be reflected in the life span date of December 31, 2051 for the Darlington station. Given that the major operating components at the Darlington plant are expected to be refurbished in the near future, Gannett Fleming finds that the

December 31, 2051 date continues to be reasonable, as recommended in the 2012 DRC review.

The previously and newly regulated hydroelectric plant dams are considered to be the life-limiting component of these stations, but since the dams have service lives that exceed that of most other classes, Gannett Fleming is of the view that they are not a significant limiting factor.

Niagara Tunnel. In March 2013, the Niagara Tunnel Project was placed in-service. The scope of the project included the design, construction and commissioning of a new, 10.2 kilometer long diversion tunnel from a new intake under the existing International Niagara Tunnel Works structure in the upper Niagara River above Niagara Falls to a new outlet canal feeding into the existing Sir Adam Beck ("SAB") Pump Generating Station canal. This tunnel supplements the diversion capacity of the two existing tunnels that bring water from the Niagara Falls to the SAB stations, and therefore enables additional generation from these facilities. The new diversion tunnel and related works were delivered under a Design-Build Agreement between OPG and its main contractor.

The new tunnel was constructed using a two-pass tunneling system, with the initial pass consisting of the excavation of the tunnel using a tunnel boring machine and the installation of the initial lining using steel supports in the tunnel roof and a full circumference layer of shortcrete (sprayed concrete). The permanent lining comprised of an impermeable membrane generally surrounding un-reinforced concrete locked in place by cement grout was installed as part of the second pass.

The Niagara Tunnel is a significant investment of approximately $1.5 billion in OPG's rate base. This cost largely related to the tunneling activity (approximately $900 million) and to the installation of the tunnel lining (approximately $375 million)[5]. The life expectation of the investment associated with the tunneling is considered to be the same as the life expectations of the two existing tunnels at the Niagara Falls. As such the investment associated with the tunneling for the project has been grouped with the investment associated with the existing tunnels. Gannett Fleming agrees with this treatment. The material and installation techniques used for the lining of the new tunnel are significantly different than the linings of the existing two tunnels. Based on its review of the technical specifications and requirements for the new tunnel as well as other documentation and discussions, Gannett Fleming supports the recommendation of the 2012 OPG DRC that a longer service life of 90 years (as compared to the 75-year life applied to the lining material in the existing tunnels) be used for the investment specific to the tunnel lining of the new tunnel. A further discussion of the recommended service life for the new tunnel lining is found in Appendix 1.

[5] Amounts are for the Niagara Tunnel addition placed in-service in March 2013.

PART III. RESULTS OF STUDY

PART III. RESULTS OF STUDY

QUALIFICATION OF RESULTS

The review of the reasonableness, and recommended alternative average service life estimates related to plant in service as of December 31, 2012 and the Niagara Tunnel placed in service in 2013 is the principal result of the study. Continued surveillance and periodic revisions are required to maintain continued use of appropriate average service lives. An assumption that life estimates can remain unchanged over a long period of time implies a disregard for the inherent variability in service lives and for the change of the composition of property in service.

SUMMARY OF RESULTS

Gannett Fleming has reviewed the life span dates and average service life estimates for all regulated generation plants and asset categories, considering the factors as identified in Part II of this report. While this review included an analysis of all asset categories, additional focus was placed on the investment categories that comprise the majority of the plant in service.

Gannett Fleming recommends the use of the life span dates as discussed in Part II of this report. Furthermore, Gannett Fleming recommends the continued use of the currently approved average service life estimates, as modified for the results of the 2011 Depreciation Study, for all accounts with the following exceptions:

- <u>Account 10318000 – Hydroelectric Head Gates, Stoplogs and Operating Mechanisms</u> – Average service life to be changed from the currently approved 50 years to 55 years;

- New Account – Hydroelectric – Roofing – Create a new plant account with a 30-year average service life to separate roofing from other plant accounts;
- New Account – Hydroelectric – Fencing – Create a new plant account with a 25-year average service life to separate fencing from other plant accounts;
- New Account – Nuclear – Roofing – Create a new plant account with a 25-year average service life to separate roofing from other plant accounts;
- New Account – Nuclear – Large Circulating Water Motors – Create a new plant account with a 30-year average service life to separate large motors (greater than 200 Hp) from other plant accounts; and
- Reclassification Between Accounts – Nuclear –Turbine Generator Controls – Reclassify nuclear turbine generator controls from Account 15411100 – Nuclear – Turbines and Auxiliaries with a 55-year average service life to Account 15600000 – Nuclear – Instrumentation and Control with a 15-year average service life.

The above recommendations for the hydroelectric plant accounts apply both to the previously and newly regulated hydroelectric assets. Gannett Fleming also agrees with the 2012 DRC recommendation that a new, separate hydroelectric plant account with an average service life estimate of 90 years be established for the tunnel lining of the new Niagara Tunnel placed in service in 2013.

A detailed discussion of the reasons and factors considered leading to the recommended changes for the above accounts is provided in Appendix 1 to this report.

Additionally, Gannett Fleming is satisfied that it is appropriate for OPG to categorize the assets making up both the previously and newly regulated hydroelectric facilities into the same plant accounts, with the same average service lives. In order for this approach to remain reasonable over time, future reviews of asset service lives for the hydroelectric plant accounts should continue to consider whether the conclusions of such reviews and the underlying analysis are applicable to both groups of assets.

DESCRIPTION OF APPENDICES

Appendix 1 to this report provides a summary of the factors considered in the review of each of the major accounts in which Gannett Fleming is recommending a change, as well as the lining of the new Niagara Tunnel. While Gannett Fleming reviewed all accounts listed in Schedule 1A and Schedule 1B, Appendix 1 only provides detailed analyses of the accounts in which a change to the average service life estimate is recommended, as well as the lining of the new Niagara Tunnel.

Appendix 2 to this report provides a listing of the newly regulated hydroelectric stations.

ONTARIO POWER GENERATION

SCHEDULE 1A - SUMMARY OF THE CURRENT AVERAGE SERVICE LIFE ESTIMATES AND
GANNETT FLEMING RECOMMENDED AVERAGE SERVICE LIFE ESTIMATES
PREVIOUSLY AND NEWLY REGULATED HYDROELECTRIC ASSETS AS AT DECEMBER 31, 2012

ASSET CLASS #	DESCRIPTION		NBV	% AGE	CURRENT	RECOMMENDED
10200000	HYDROELECTRIC - SUBSTRUCTURES AND SUPERSTRUCTURES	$	1,227,972,792	19.79%	100	100
10101000	HYDROELECTRIC - EXCAVATION, DREDGING, RIPRAPPING AND GROUTING	$	1,380,649,053	22.25%	100	100
10312000	HYDROELECTRIC - DAMS - CONCRETE	$	991,676,359	15.98%	100	100
10318000	HYDROELECTRIC - GATES, STOPLOGS AND OPERATING MECHANISMS	$	361,275,033	5.82%	50	55
10306000	HYDROELECTRIC - SURGETANK, PIPELINE, CONDUIT, PENTSTOCK	$	292,982,384	4.72%	75	75
10400000	HYDROELECTRIC - TURBINES AND GOVERNORS	$	213,248,856	3.44%	70	70
10501000	HYDROELECTRIC - MAIN ROTATIONAL ELECTRICAL EQUIPMENT - LESS WINDINGS	$	221,787,828	3.57%	75	75
10301000	HYDROELECTRIC - LINING OF TUNNELS AND PERMANENT SHAFTS	$	219,912,108	3.54%	75	75
10510000	HYDROELECTRIC - MAIN POWER AND STATION SERVICE - TRANSMISSION	$	175,590,706	2.83%	50	50
10500000	HYDROELECTRIC - MAIN ROTATIONAL ELECTRICAL EQUIPMENT - WINDINGS	$	114,912,729	1.85%	40	40
10311000	HYDROELECTRIC - DAMS - EARTH AND ROCKFILL	$	106,329,529	1.71%	100	100
10405000	HYDROELECTRIC - TURBINE RUNNERS	$	96,535,236	1.56%	40	40
10210000	HYDROELECTRIC - SERVICE AND EQUIPMENT BUILDINGS	$	101,137,556	1.63%	55	55
10502000	HYDROELECTRIC - BUS, SWITCHING AND POWER CABLE	$	85,327,386	1.37%	45	45
10300000	HYDROELECTRIC - CANAL, FOREBAY, RETAINING WALL LINING	$	83,670,918	1.35%	75	75
10504000	HYDROELECTRIC - CONTROL BOARDS AND SWITCHBOARDS	$	77,122,794	1.24%	25	25
10700000	HYDROELECTRIC - AUXILIARY SYSTEMS	$	72,291,792	1.16%	30	30
10302000	HYDROELECTRIC - SPILLWAYS, SLUICES, FLUMES	$	72,513,556	1.17%	75	75
10100000	HYDROELECTRIC - LAND	$	37,317,826	0.60%	100	100
10709000	HYDROELECTRIC - OWNED BRIDGES, RAILWAY TRACK, WHARVES	$	54,666,182	0.88%	65	65
10505000	HYDROELECTRIC - STATION SERVICE ELECTRICAL EQUIPMENT	$	44,045,969	0.71%	50	50
10601000	HYDROELECTRIC - MECHANICAL EQUIPMENT - CRANES AND FOLLOWERS	$	45,064,408	0.73%	55	55
10205000	HYDROELECTRIC - OUTDOOR STRUCTURES	$	20,878,634	0.34%	75	75
10710000	HYDROELECTRIC - FIRE PROTECTION SYSTEMS	$	27,019,773	0.44%	20	20
10503000	HYDROELECTRIC - HIGH VOLTAGE SWITCHING	$	16,335,367	0.26%	40	40
10503100	HYDROELECTRIC - REVENUE METERING - HIGH VOLTAGE SWITCHING, CONTROL BOARDS AND SWITCHBC	$	13,162,790	0.21%	30	30
10311100	HYDROELECTRIC - DAMS - TIMBER CRIB	$	8,624,328	0.14%	60	60
16210000	ADMINISTRATION AND SERVICE BUILDINGS - PERMANENT BLDGS. ROADS AND SITE IMPROVEMENT	$	7,852,168	0.13%	50	50
10991000	HYDROELECTRIC - MAJOR SPARES	$	7,207,631	0.12%	100	100
10315000	HYDROELECTRIC - STEEL RACKS	$	6,220,914	0.10%	40	40
10302100	HYDROELECTRIC - PUBLIC SAFETY/WARNING BOOMS	$	4,066,117	0.07%	15	15
16550000	ADMINISTRATION AND SERVICE BUILDINGS - LAN CABLE	$	3,922,188	0.06%	10	10
10531000	HYDROELECTRIC - CIRCUIT BREAKERS	$	4,048,211	0.07%	50	50
10720000	HYDROELECTRIC - SECURITY SYSTEMS	$	1,987,371	0.03%	10	10
16100000	ADMINISTRATION AND SERVICE BUILDINGS - LANDS	$	591,758	0.01%	N/A	N/A
16560100	ADMINISTRATION AND SERVICE BUILDINGS - ADMINSTRATIVE SYSTEMS SW	$	830,257	0.01%	5	5
16230000	ADMINISTRATION AND SERVICE BUILDINGS - FRAME & METAL	$	11,000	0.00%	25	25
18400000	COMMUNICATIONS - POWER LINE EQUIPMENT	$	591,742	0.01%	15	15
18460000	COMMUNICATIONS - DATA ACQ. EQUIP., MAN MACHINE INTERFACE EQUIPMENT	$	105,828	0.00%	15	15
18630000	COMMUNICATIONS - OPTICAL WIRE	$	644,287	0.01%	25	25
16551000	ADMINISTRATION AND SERVICE BUILDINGS - LAN ELECTRICAL CONNECTING DEVICES	$	777,362	0.01%	5	5
18633000	COMMUNICATIONS - OPTICAL WIRE - REVENUE METERING	$	715,860	0.01%	30	30
18540000	COMMUNICATIONS - ADMINISTRATIVE TELEPHONE EQUIPMENT	$	216,553	0.00%	7	7

ONTARIO POWER GENERATION

SCHEDULE 1A - SUMMARY OF THE CURRENT AVERAGE SERVICE LIFE ESTIMATES AND
GANNETT FLEMING RECOMMENDED AVERAGE SERVICE LIFE ESTIMATES
PREVIOUSLY AND NEWLY REGULATED HYDROELECTRIC ASSETS AS AT DECEMBER 31, 2012

ASSET CLASS #	DESCRIPTION	NBV		% AGE	CURRENT	RECOMMENDED
18600000	COMMUNICATIONS - WOOD POLE, COMMUNICATION CABLE APPARATUS AND BOOTHS	$	77,039	0.00%	40	40
18530000	COMMUNICATIONS - TIMBER AND STEEL STRUCTURES	$	17,738	0.00%	40	40
18100000	COMMUNICATIONS - LAND	$	879	0.00%	100	100
16630000	ADMINSITRATION AND SERVICE BUILDINGS - SYSTEMS & EQUIPMENT	$	132,754	0.00%	20	20
18200000	COMMUNICATIONS - BUILDINGS	$	58,601	0.00%	50	50
18500000	COMMUNICATIONS - RADIO EQUIPMENT	$	5,974	0.00%	15	15
	MINOR FIXED ASSETS	$	4,094,653	0.07%		
NEW	HYDROELECTRIC - NIAGARA FALLS - NEW TUNNEL LINING	$	-	0.00%	N/A	90
NEW	HYDROELECTRIC - BUILDINGS - ROOFING	$	-	0.00%	N/A	30
NEW	HYDROELECTRIC - FENCING	$	-	0.00%	N/A	25
	GRAND TOTAL	**$**	**6,206,228,777**	**100.00%**		

ONTARIO POWER GENERATION

SCHEDULE 1B. SUMMARY OF CURRENT AVERAGE SERVICE LIFE ESTIMATES AND GANNETT FLEMING RECOMMENDED AVERAGE SERVICE LIFE ESTIMATES

PRESCRIBED NUCLEAR ASSETS AS AT DECEMBER 31, 2012

ASSET CLASS #	DESCRIPTION	NBV	% AGE	CURRENT	RECOMMENDED
15200000	NUCLEAR - BUILDINGS AND STRUCTURES	202,581,250	13.84%	55	55
15340000	NUCLEAR - PROCESS SYSTEMS	165,034,350	11.27%	55	55
15600000	NUCLEAR - INSTRUMENTATION AND CONTROL - PA&BG	163,390,095	11.16%	15	15
15701000	NUCLEAR - SERVICE WATER AND FIRE PROTECTION SYSTEM	122,983,880	8.40%	25	25
15720000	NUCLEAR - COMMON SERVICE SYSTEMS	94,104,574	6.43%	35	35
15121000	NUCLEAR - ELECTRONIC SITE SECURITY SYSTEM	77,170,667	5.27%	15	15
15120000	NUCLEAR - YARD FACILITIES	62,632,092	4.28%	50	50
15450000	NUCLEAR - CONDENSER TUBING	59,936,357	4.09%	30	30
15561000	NUCLEAR - AC STANDBY POWER - PB&DG	45,936,441	3.14%	55	55
15361000	NUCLEAR - IRRADIATED FUEL BAYS - PICKERING B	36,512,986	2.49%	65	65
15550000	NUCLEAR - REACTOR BUILDING CABLING	31,313,114	2.14%	40	40
16310000	ADMINISTRATION AND SERVICE BUILDINGS - NUCLEAR TRAINING SIMULATORS	29,502,112	2.02%	45	45
15991000	NUCLEAR - MAJOR / STRATEGIC SPARES	23,310,388	1.59%	100	100
15341100	NUCLEAR - MODERATOR HEAT EXCHANGERS-PICKERING	21,664,508	1.48%	25	25
16560100	ADMINISTRATION AND SERVICE BUILDINGS - INTANGIBLES ADMINISTRATION SYSTEM SOFTWARE	20,482,148	1.40%	5	5
15510000	NUCLEAR - STATION SERVICE MAIN TRANSFORMERS AND AC POWER DISTRIBUTION SYSTEMS-PA&BG	18,723,596	1.28%	40	40
15460000	NUCLEAR - AUXILIARY SYSTEMS - PB&DG	17,433,082	1.19%	40	40
15500000	NUCLEAR - MAIN POWER OUTPUT SYSTEM	17,311,287	1.18%	35	35
15421000	NUCLEAR - GENERATOR ROTORS, STATORS AND AUXILIARY SYSTEMS - PB&DG	14,463,334	0.99%	55	55
15560000	NUCLEAR - AC STANDBY POWER - PA&BG	12,946,426	0.88%	40	40
15710000	NUCLEAR - WATER TREATMENT PLANT	11,755,949	0.80%	20	20
15352100	NUCLEAR - SHUTDOWN COOLING SYSTEM HEAT EXCHANGERS-DARLINGTON	7,180,243	0.49%	30	30
16540000	ADMINSTRATION AND SERVICE BUILDINGS - ADMINISTRATIVE TELECOM EQUIPMENT	6,817,736	0.47%	7	7
15330000	NUCLEAR - REACTIVITY CONTROL UNITS	6,428,607	0.44%	40	40
15461000	NUCLEAR - AUXILIARY SYSTEMS - PB&BG	5,888,839	0.40%	55	55
15711000	NUCLEAR - CIRCULATING WATER - PA&BG	5,645,173	0.39%	55	55
16210000	ADMINSTRATION AND SERVICE BUILDINGS - PERMANENT BUILDINGS, ROADS AND SITE IMPROVEMENTS	5,189,964	0.35%	50	50
15501000	NUCLEAR - REVENUE METERING - MAIN POWER OUTPUT, INSTRUMENTION AND CONTROL-PICK/DARL	4,420,168	0.30%	30	30
15990000	NUCLEAR - ALTERNATE SPARES	3,870,028	0.26%	100	100
15300000	NUCLEAR - REACTOR VESSELS	3,255,283	0.22%	40	40
16211000	ADMINISTRATION AND SERVICE BUILDINGS - BUILDINGS - LEASED	3,053,583	0.21%	10	10
15700000	NUCLEAR - CIRCULATING WATER	2,967,609	0.20%	40	40
16630000	ADMINISTRATION AND SERVICE BUILDINGS - BUILDING SYSTEMS AND EQUIPMENT	2,378,027	0.16%	20	20
15370000	NUCLEAR - TRITIUM REMOVAL FACILITY	2,367,846	0.16%	30	30
15411100	NUCLEAR - TURBINES, AUXILIARY EQUIPMENT, STEAM REHEATER TUBE - PB&DG	1,920,354	0.13%	55	55
15531000	NUCLEAR - BUILDING ELECTRICAL SERVICE SUPPLIES - PB&DG	1,586,505	0.11%	55	55
15352000	NUCLEAR - SHUTDOWN COOLING SYSTEM HEAT EXCHANGERS-PICKERING	1,259,362	0.09%	25	25
16550000	ADMINISTRATION AND SERVICE BUILDINGS - LAN CABLE	1,147,295	0.08%	10	10
18500000	COMMUNICATIONS - RADIO EQUIPMENT	1,030,056	0.07%	15	15
16230000	ADMINISTRATION AND SERVICE BUILDINGS - BUILDINGS- FRAME AND METAL CLAD	1,005,387	0.07%	25	25

ONTARIO POWER GENERATION

SCHEDULE 1B. SUMMARY OF CURRENT AVERAGE SERVICE LIFE ESTIMATES AND
GANNETT FLEMING RECOMMENDED AVERAGE SERVICE LIFE ESTIMATES
PRESCRIBED NUCLEAR ASSETS AS AT DECEMBER 31, 2012

ASSET CLASS #	DESCRIPTION	NBV	% AGE	CURRENT	RECOMMENDED
15511000	NUCLEAR - STATION SERVICE MAIN TRANSFORMERS AND AC POWER DISTRIBUTION SYSTEMS - PB&DG	896,419	0.06%	55	55
15541000	NUCLEAR - ELECTRICAL AUXILIARY SYSTEM-PB&DG	791,287	0.05%	55	55
15400000	NUCLEAR - TURBINES, AUXILIARY EQUIPMENT, STEAM REHEATER TUBE -PA&BG	693,921	0.05%	40	40
16311000	ADMINISTRATION AND SERVICE BUILDINGS - NUCLEAR SIMULATORS - DESIGN UPGRADES	456,887	0.03%	10	10
15360000	NUCLEAR - IRRADIATED FUEL BAYS - PICKERING A	400,039	0.03%	40	40
15311000	NUCLEAR - FUEL CHANNEL ASSEMBLIES	154,089	0.01%	25	25
15430000	NUCLEAR - EXCITERS	75,910	0.01%	30	30
18633000	COMMUNICATIONS - OPTICAL WIRE - REVENUE METERING	38,917	0.00%	30	30
18460000	COMMUNICATIONS - DATA ACQ. EQUIP., MAN MACHINE INTERFACE EQUIPMENT	24,631	0.00%	15	15
18630000	COMMUNICATIONS - OPTICAL WIRE	8,636	0.00%	25	25
	MINOR FIXED ASSETS - SERVICE EQUIPMENT	134,697,036	9.20%		
	MINOR FIXED ASSETS - OTHER	8,923,873	0.61%		
NEW	NUCLEAR - ROOFING		0.00%	N/A	25
NEW	NUCLEAR - LARGE CIRCULATING WATER MOTORS - OVER 200 HP		0.00%	N/A	30
	TOTAL	**1,463,762,346**	**100.00%**		
	ASSET RETIREMENT COSTS (ARC)	1,510,363,609			
	GRAND TOTAL	**2,974,125,954**			

APPENDIX 1

ONTARIO POWER GENERATION INC.
Detailed Discussion Related To Accounts Where An
Average Service Life Change Is Recommended

Account 10318000 – Hydroelectric Gates, Stoplogs and Operating Mechanisms

Current Average Service Life Estimate – 50 years

Recommended Average Service Life Estimate – 55 years

Average of Peer Average Service Lives – 72 years (Range from 50 to 100 years)

Discussion:

This account includes the investment in a number of the operating mechanisms related to the hydroelectric dams, including the head gates and stoplogs. Since the 1990's, OPG has been engaged in a significant gate replacement program. The average replacement age of the original gates has been 40 to 60 years. OPG's Dam Safety Program mandates rigorous annual functional testing, inspection and gate maintenance. Experience gained through these monitoring and assessment programs has shown that after 40-60 years of service life, the gates typically require an extensive rebuild. Replacement parts or components may no longer be commercially available requiring extensive and costly re-engineering to restore original functionality. Replacing with a current gate design takes full advantage of improvements in manufacturing processes, operating mechanism design, material properties, electronic controls, etc. that have occurred over the past 50 years.

Integration of wind and other intermittent renewable sources of generation has increased over time and is expected to continue into the future. As a result, increased cycling of hydro generating units has been experienced, along with a similar increase in gate operation cycles.

In making the recommendation for an increase to the average service life estimate, Gannett Fleming has specifically noted that the life estimates of the peer group have been increasing in recent depreciation studies. A review of peer companies has indicated average service life estimates for the peer group of companies now range from 50 years to as long as 100 years. However, it is noted that the peer companies at the longer end of this range include this investment in their overall dam structures accounts. With the removal of the longer life peer indications from the peer analysis the comparable life estimates of the peer group range from 50 to 80 years with an overall average of 55 years.

The recommended 55-year average service life estimate has been developed giving consideration to all of the above influences. It is expected that improvements in gate design and reliability will be partially offset by moderately increasing frequency of operation, thus the currently assigned life of 50 years can be increased to 55 years, which is consistent with the indications from the adjusted peer analysis.

ONTARIO POWER GENERATION INC.
Detailed Discussion Related To Accounts Where An
Average Service Life Change Is Recommended

NEW ACCOUNT – Hydroelectric Fencing

Current Average Service Life Estimate – 100 years

Recommended Average Service Life Estimate – 25 years

Average of Peer Average Service Lives – 25 to 30 years

Discussion:

This account would include the OPG investment related to site parameter fencing at the hydroelectric facilities. During the operational tours conducted by Gannett Fleming it was specifically noted that OPG had recently undergone a significant program to upgrade its site parameter fencing. OPG intends to continue its focus on public safely through the planned continuation of this program. As such, it is appropriate to set up a separate account for fencing.

A review of the peer companies has indicated average service life estimates ranging from 25 to 30 years with most peer utilities using 25 years. Therefore, based on a peer analysis, an average service life of 25 years is reasonable. Discussions with OPG operational staff have also confirmed that the use of a 25-year average service life for this new account is reasonable.

ONTARIO POWER GENERATION INC.
Detailed Discussion Related To Accounts Where An
Average Service Life Change Is Recommended

NEW ACCOUNT – Hydroelectric Roofing

Current Average Service Life Estimate – 75 to 100 years

Recommended Average Service Life Estimate – 30 years

Average of Peer Average Service Lives – 30 years

Discussion:

This proposed new account relates to the OPG investment in roofing which has shown to have a materially shorter life than the associated buildings. Historically, several of OPG hydroelectric plant roofing systems have reached between 25 to 50 year service life milestones before complete replacement. However, the service life is dependent on the type of roofing material utilized and exposure conditions. The original multi-layer tar and felt roofing systems (with gravel protection) have averaged over 40 years, while the newer roofing systems (EPDM, PVC and TPO) have averaged about 25 to 30 years. The past issues (e.g., premature joint failures, cracking, poor wear resistance, etc.) with the newer systems have been partially resolved through modern material formulations and installation improvements.

A review of the peer companies that have componentized roofing into a separate category has indicated average service life estimates of 30 years. It is also the view of the OPG operational staff that the roofing materials and installations systems currently in place systems will achieve an average service life of 30 years. Therefore, based on the peer analysis, discussions with OPG operational staff, and Gannett Fleming's experience the use of a 30-year average service life for this new account is proposed.

ONTARIO POWER GENERATION INC.
Detailed Discussion Related To Accounts Where An
Average Service Life Change Is Recommended

NEW ACCOUNT – Nuclear Large Circulating Water Motors

Current Average Service Life Estimate – 40 to 55 years

Recommended Average Service Life Estimate – 30 years

Average of Peer Average Service Lives –N/A

Discussion:

This proposed new account relates to the OPG investment in large electric motors of more than 200 horsepower with operating voltages between 2kV and 15kV being used for critical operations and safety systems. A review of operational benchmark information from the Electric Power Research Institute ("EPRI") and the United States Nuclear Regulatory Commission ("US NRC") indicates that the expected life of a large high voltage motor ranges from 24 years to 40 years. Due to the high voltages and large rotating masses involved, the electrical and mechanical wear and tear occurs in these motors at a higher rate than experienced by smaller motors. OPG operational experience has shown that large motors, such as the Darlington Heat Transport Pump Motors, are approaching failure at the rates predicted by the US NRC-sponsored research and EPRI. A complete teardown and rebuild is required to extend the life of these motors. In the case of the Darlington motors, spare motors are being purchased to facilitate the rebuild of the 16 in-service motors.

Given the different average service life expectations associated with these motors, Gannett Fleming recommends the creation of a new account for the investment in large circulating water motors with an average service life of 30 years. The recommended life of 30 years is consistent with the mid-point of the expected lives in the US NRC-sponsored and EPRI reports and OPG's operational experience.

ONTARIO POWER GENERATION INC.
Detailed Discussion Related To Accounts Where An
Average Service Life Change Is Recommended

NEW ACCOUNT – Nuclear Roofing

Current Average Service Life Estimate – 55 years

Recommended Average Service Life Estimate – 25 years

Average of Peer Average Service Lives – N/A

Discussion:

This proposed new account relates to the OPG investment in roofing of Nuclear Buildings and Structures which has shown to have a materially shorter life than the associated buildings. A 2012 Station Roof Replacement Project was initiated as the station roofs were reaching the end of their 25-year design life. OPG's internal assessments have indicated that station roofing requires repair or replacement, with the condition of the roofing deteriorating due to its age. A number of work orders associated with the condition of the roofs been initiated.

Based on the design life and the operating experience of OPG, Gannett Fleming recommends that OPG should create a new account for nuclear roofing, with a 25-year average service life.

ONTARIO POWER GENERATION INC.
Detailed Discussion Related To Accounts Where An
Average Service Life Change Is Recommended

Reclassification of Nuclear Turbine Generator Controls from Account 15411100 – Nuclear Turbines and Auxiliaries to Account 15600000 – Nuclear Instrumentation and Control

Current Average Service Life Estimate – 55 years as part of Account 15411100

Recommended Average Service Life Estimate – 15 years as part of Account 15600000

Average of Peer Average Service Lives – 15 to 25 years

Discussion:

Gannett Fleming recommends a change in the coding of the nuclear turbine generator controls from Account 15411100 – Nuclear Turbines and Auxiliaries to Account 15600000 – Nuclear Instrumentation and Control. It is the view of Gannett Fleming that the emergence of digital technology for turbine generator control equipment results in the 55-year life estimate associated with Account 15411100 being no longer appropriate for these specific assets. It is also noted that, in general, the turbine generator control systems are more similar in technology and life characteristics to the assets recorded in Account 15600000. As such, Gannett Fleming recommends that these assets be reclassified to Account 15600000.

ONTARIO POWER GENERATION INC.
Detailed Discussion Related To Niagara Tunnel Lining

NEW ACCOUNT – Hydroelectric – Niagara Falls- New Tunnel Lining

Current Average Service Life Estimate – N/A

Recommended Average Service Life Estimate – 90 years

Average of Peer Average Service Lives – N/A

Discussion:

The investment in this account relates to the lining material of the Niagara Tunnel that was placed into service in the first quarter of 2013. The 2011 Depreciation Study conducted by Gannett Fleming and internal OPG depreciation reviews have recommended a life estimate of 75 years for the linings associated with the two original tunnels at Niagara Falls. This estimated service life for existing OPG tunnel linings of 75 years is consistent with industry practice.

The Niagara Tunnel Project ("NTP") was an extremely large, complex, and challenging construction project with an estimated total capital cost of approximately $1.5 Billion. Most of the investment was placed in service in March 2013. Based on its review of the NTP, it is the view of Gannett Fleming that the tunnel excavation investment would have a similar life of 100 years as expected for the existing two Niagara tunnels and other hydroelectric excavation. However, Gannett Fleming's review also specifically noted that the NTP tunnel lining material installation procedures, were specifically designed and the tunnel was specifically constructed for a service life of 90 years. In fact, the 90-year design life was a specific requirement of the NTP to be considered by contractors working on this project. As such, the technical specifications and material used in both the new tunnel construction and tunnel lining have a stated mandatory requirement for a service life of 90 years for the lining system and structures of the Niagara Tunnel Facility.

In making the above recommendation associated with the new tunnel lining, Gannett Fleming's review included:

- A tour of the new tunnel construction activity in 2011 as part of the Sir Adam Beck facility tour conducted as part of the 2011 Depreciation Study;
- Technical design specifications for the project;
- Owner's mandatory requirements for the tunnel facility contained in OPG's Design and Build Contract with Strabag AG;
- A number of discussions with NTP staff regarding the project (and specifically the tunnel lining);
- DRC work and documentation related to the lining investment for the new tunnel; and

- OPG's evidence with respect to the NPT filed with the OEB as part of the EB-2013-0321 proceeding (Ex. D1-2-1).
  .

Gannett Fleming considers the above reviews as sufficient evidence to establish the average service life for the new Niagara Tunnel lining at 90 years, as recommended by the 2012 DRC. As the two existing tunnels are recommended to continue to be depreciated over 75 years, the investment associated with the 2013 tunnel lining should be segregated into a separate account.

APPENDIX 2

APPENDIX 2

ONTARIO POWER GENERATION

NEWLY REGULATED HYDROELECTRIC FACILITIES

Ottawa-St. Lawrence Plant Group:

Arnprior Station
Barrett Chute Station
Calabogie Station
Mountain Chute Station
Stewartville Station
Chats Falls Station
Chenaux Station
Des Joachims Station
Otto Holden Station

Northeast Plant Group:

Abitibi Canyon Station
Otter Rapids Station
Lower Notch Station
Matabitchuan Station
Indian Chute Station

Central Hydro Plant Group:

Auburn Station
Big Chute Station
Big Eddy Station
Bingham Chute Station
Coniston Station
Crystal Falls Station
Elliot Chute Station
Eugenia Falls Station
Frankford Station
Hagues Reach Station
Hanna Chute Station
High Falls Station
Lakefield Station
McVittie Station
Merrickville Station
Meyersburg Station
Nipissing Station
Ragged Rapids Station
Ranney Falls Station
Seymour Station
Sidney Station
Sills Island Station
South Falls Station
Stinson Station
Trethewey Falls Station

Northwest Plant Group:

Aquasabon Station
Alexander Station
Cameron Falls Station
Caribou Falls Station
Kakabeka Falls Station
Manitou Falls Station
Pine Portage Station
Silver Falls Station
Whitedog Falls Station

Attachment 1

DETAILED LIST OF UTILITIES THROUGHOUT NORTH AMERICA USING ELG PROCEDURE

Company Name	Approved by:
Allegheny Energy Supply, Inc.	Gannett Fleming cannot confirm that ELG has been approved
AltaGas Utilities Inc.	Alberta Utilities Commission
ATCO Gas	Alberta Utilities Commission
ATCO Electric	Alberta Utilities Commission
Aqua Pennsylvania	Pennsylvania Public Utilities Commission
Citizens Energy Group	Gannett Fleming cannot confirm that ELG has been approved
Columbia Gas of Kentucky	Kentucky Public Service Commission
Columbia Gas of Pennsylvania	Pennsylvania Public Utilities Commission
Duquesne Light Company	Pennsylvania Public Utilities Commission
Duke Energy Indiana	Indiana Utility Regulatory Commission
Duke Energy Kentucky	Kentucky Public Service Commission
East Kentucky Power Cooperative	Kentucky Public Service Commission
Enmax Power Corporation	Alberta Utilities Commission
FortisAlberta Utilities, Inc.	Alberta Utilities Commission
Kokomo Gas and Fuel Company	Indiana Utility Regulatory Commission
National Fuel Gas Distribution Corp - Pa Division	Pennsylvania Public Utilities Commission
Newfoundland Power Limited	Newfoundland and Labrador Board of Commissioners of Public Utilities
Northern Indiana Fuel and Light Company Inc.	Indiana Utility Regulatory Commission
Northern Indiana Public Service Company	Indiana Utility Regulatory Commission
Northland Utilities (NWT) Limited	Northwest Territories Public Utilities Board
Northland Utilities (Yellowknife) Limited	Northwest Territories Public Utilities Board
Nova Scotia Power, Inc.	Nova Scotia Utility and Review Board
Pennsylvania American Water Company	Pennsylvania Public Utilities Commission
Peoples Equitable Gas	Pennsylvania Public Utilities Commission
Peoples Natural Gas	Pennsylvania Public Utilities Commission
Peoples TWP	Pennsylvania Public Utilities Commission
Public Service Company of Colorado	Colorado Public Utilities Commission
Quilliq Power Corporation	Nunavut Utility Rates Review Council
UGI Penn Natural Gas, Inc.	Pennsylvania Public Utilities Commission
UGI Utilities, Inc. - Electric Division	Pennsylvania Public Utilities Commission
York Water Company	Pennsylvania Public Utilities Commission

Section:	PUB/MH I-42b	Page No.:	
Topic:			
Subtopic:	Financial Results & Forecast		
Issue:	Depreciation Expense		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide Gannett Fleming's reference indicating the use of the ELG procedure by Qulliq Energy.

RATIONALE FOR QUESTION:

To assess impacts and usage of ELG methodology and ASL methodology for regulatory purposes in other jurisdictions.

RESPONSE:

The reference to Qulliq Energy using the ELG method in response to PUB/MH I-42b was incorrect. Qulliq Energy uses the ASL procedure for determining depreciation.

6

Section:	Appendix 5.6	Page No.:	Page 7 - 14
Topic:	Depreciation		
Subtopic:			
Issue:			

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide pages 7 through 14 separately breaking out the net salvage component of the ASL rates from the asset life depreciation component.

RATIONALE FOR QUESTION:

To review the 2014 Depreciation Study and implications on rate payers.

RESPONSE:

Please see the schedules below breaking out the net salvage component of the ASL rates from the asset life component.

Depreciation Rate Tables (Electric operations) with ASL without Net Salvage

DEPRECIABLE GROUP (Electric Operations)	Expected Service Life	2014-15 Previous ASL Rate %	2014-15 Approved ASL Rate %	2014-15 ASL Rate % w/o Net Salvage	2015-16 Approved ELG Rate %
HYDRAULIC GENERATION					
GREAT FALLS					
DAMS, DYKES AND WEIRS	125	1.28	1.32	1.11	1.12
POWERHOUSE	125	1.27	1.28	1.07	1.07
POWERHOUSE RENOVATIONS	40	4.40	2.67	2.41	2.41
SPILLWAY	80	1.59	1.50	1.26	1.35
WATER CONTROL SYSTEMS	65	2.07	1.52	1.28	1.35
ROADS AND SITE IMPROVEMENTS	50	2.33	2.42	2.18	2.42
TURBINES AND GENERATORS	60	1.82	2.25	1.99	2.03
GOVERNORS AND EXCITATION SYSTEM	50	2.11	2.25	1.99	2.06
LICENCE RENEWAL	50	2.00	2.04	2.04	2.04
A/C ELECTRICAL POWER SYSTEMS	55	2.10	1.84	1.55	1.67
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	4.43	3.86	3.20	3.79
AUXILIARY STATION PROCESSES	50	2.59	2.03	1.75	2.10
SUPPORT BUILDINGS	65	1.73	1.69	1.42	1.36
SUPPORT BUILDING RENOVATIONS	20	5.50	5.50	5.00	5.00
POINTE DU BOIS - Original					
DAMS, DYKES AND WEIRS	125	3.63	3.10	2.70	2.70
POWERHOUSE	125	4.39	2.94	2.55	2.55
POWERHOUSE RENOVATIONS	40	5.24	4.10	3.71	3.71
SPILLWAY	80	10.76	84.53	73.57	73.37
WATER CONTROL SYSTEMS	65	3.35	2.11	1.72	1.73
ROADS AND SITE IMPROVEMENTS	50	3.36	4.09	3.68	3.80
TURBINES AND GENERATORS	60	4.04	2.84	2.44	2.44
GOVERNORS AND EXCITATION SYSTEM	50	5.24	4.02	3.65	3.68
LICENCE RENEWAL	50	4.76	3.85	3.85	3.85
A/C ELECTRICAL POWER SYSTEMS	55	4.58	3.16	2.76	2.78
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	5.12	4.30	3.80	4.26
AUXILIARY STATION PROCESSES	50	4.03	3.71	3.29	3.59
SUPPORT BUILDINGS	65	2.93	2.99	2.59	2.59
SUPPORT BUILDING RENOVATIONS	20	5.50	4.47	3.84	3.84
POINTE DU BOIS - New					
DAMS, DYKES AND WEIRS	125	-	0.91	0.83	0.85
SPILLWAY	80	1.47	1.37	1.25	1.49
WATER CONTROL SYSTEMS	65	-	1.69	1.54	1.64
ROADS AND SITE IMPROVEMENTS	50	-	2.20	2.00	2.36
A/C ELECTRICAL POWER SYSTEMS	55	-	2.40	2.18	1.94
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	-	4.40	4.00	4.54
AUXILIARY STATION PROCESSES	50	-	2.20	2.00	3.01
SUPPORT BUILDINGS	65	-	1.69	1.54	1.65
SUPPORT BUILDING RENOVATIONS	20	-	5.50	5.00	5.00
SEVEN SISTERS					
DAMS, DYKES AND WEIRS	125	1.03	1.06	0.88	0.90
POWERHOUSE	125	0.90	0.91	0.73	0.74
POWERHOUSE RENOVATIONS	40	4.40	2.67	2.41	2.41
SPILLWAY	80	1.17	1.36	1.14	1.17
WATER CONTROL SYSTEMS	65	1.80	1.25	1.02	1.02
ROADS AND SITE IMPROVEMENTS	50	1.84	1.78	1.46	1.30
TURBINES AND GENERATORS	60	1.64	1.84	1.61	1.69
GOVERNORS AND EXCITATION SYSTEM	50	2.00	2.22	1.99	2.12
LICENCE RENEWAL	50	2.00	2.00	2.00	2.00
A/C ELECTRICAL POWER SYSTEMS	55	1.91	1.74	1.48	1.56
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	3.73	3.80	3.19	3.44
AUXILIARY STATION PROCESSES	50	2.13	1.91	1.65	2.03
SUPPORT BUILDINGS	65	1.74	1.65	1.44	1.52
SUPPORT BUILDING RENOVATIONS	20	5.50	5.50	5.00	5.00

Depreciation Rate Tables (Electric operations) with ASL without Net Salvage cont'd

DEPRECIABLE GROUP (Electric Operations)	Expected Service Life	2014-15 Previous ASL Rate %	2014-15 Approved ASL Rate %	2014-15 ASL Rate % w/o Net Salvage	2015-16 Approved ELG Rate %
SLAVE FALLS					
DAMS, DYKES AND WEIRS	125	1.69	1.71	1.54	1.54
POWERHOUSE	125	1.58	1.59	1.42	1.43
POWERHOUSE RENOVATIONS	40	4.40	2.75	2.50	2.50
SPILLWAY	80	1.87	1.82	1.64	1.74
WATER CONTROL SYSTEMS	65	2.18	1.77	1.58	1.65
ROADS AND SITE IMPROVEMENTS	50	2.20	2.30	2.08	2.36
TURBINES AND GENERATORS	60	1.79	1.91	1.70	1.81
GOVERNORS AND EXCITATION SYSTEM	50	2.20	2.22	2.01	2.12
LICENCE RENEWAL	50	2.00	2.00	2.00	2.00
A/C ELECTRICAL POWER SYSTEMS	55	2.21	2.00	1.79	1.91
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	4.72	4.42	3.96	4.56
AUXILIARY STATION PROCESSES	50	2.73	2.34	2.11	2.70
SUPPORT BUILDINGS	65	1.81	2.01	1.81	1.89
SUPPORT BUILDING RENOVATIONS	20	5.50	5.50	5.00	5.00
PINE FALLS					
DAMS, DYKES AND WEIRS	125	1.17	1.23	1.10	1.12
POWERHOUSE	125	0.83	0.83	0.67	0.71
POWERHOUSE RENOVATIONS	40	4.40	2.67	2.41	2.41
SPILLWAY	80	1.60	1.50	1.35	1.49
WATER CONTROL SYSTEMS	65	1.95	1.28	1.03	1.06
ROADS AND SITE IMPROVEMENTS	50	1.81	1.68	2.00	1.61
TURBINES AND GENERATORS	60	1.47	1.62	1.33	1.37
GOVERNORS AND EXCITATION SYSTEM	50	2.20	2.20	2.00	2.13
LICENCE RENEWAL	50	2.00	2.00	2.00	2.00
A/C ELECTRICAL POWER SYSTEMS	55	2.06	1.83	1.56	1.58
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	4.25	4.17	3.61	4.04
AUXILIARY STATION PROCESSES	50	2.54	1.78	1.50	1.81
SUPPORT BUILDINGS	65	1.61	1.62	1.40	1.56
SUPPORT BUILDING RENOVATIONS	20	5.50	5.50	5.00	5.00
COMMUNITY DEVELOPMENT COSTS	78	1.17	1.28	1.28	1.28
MCARTHUR FALLS					
DAMS, DYKES AND WEIRS	125	0.91	1.12	0.98	1.00
POWERHOUSE	125	0.83	0.84	0.68	0.72
POWERHOUSE RENOVATIONS	40	4.40	2.67	2.41	2.41
SPILLWAY	80	1.19	1.19	0.86	0.97
WATER CONTROL SYSTEMS	65	2.06	1.37	1.15	1.25
ROADS AND SITE IMPROVEMENTS	50	1.99	1.94	1.59	1.71
TURBINES AND GENERATORS	60	1.06	1.35	0.97	0.94
GOVERNORS AND EXCITATION SYSTEM	50	2.10	2.08	1.78	1.94
LICENCE RENEWAL	50	2.00	2.00	2.00	2.00
A/C ELECTRICAL POWER SYSTEMS	55	1.90	1.72	1.37	1.32
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	4.29	3.62	2.88	2.74
AUXILIARY STATION PROCESSES	50	2.58	1.82	1.54	1.85
SUPPORT BUILDINGS	65	1.63	1.73	1.57	1.67
SUPPORT BUILDING RENOVATIONS	20	5.50	5.50	5.00	5.00

Depreciation Rate Tables (Electric operations) with ASL without Net Salvage cont'd

DEPRECIABLE GROUP (Electric Operations)	Expected Service Life	2014-15 Previous ASL Rate %	2014-15 Approved ASL Rate %	2014-15 ASL Rate % w/o Net Salvage	2015-16 Approved ELG Rate %
KELSEY					
DAMS, DYKES AND WEIRS	125	1.05	1.13	1.01	1.03
POWERHOUSE	125	0.89	1.18	1.06	1.08
POWERHOUSE RENOVATIONS	40	4.40	2.75	2.50	2.50
SPILLWAY	80	1.34	1.71	1.47	1.58
WATER CONTROL SYSTEMS	65	2.09	1.70	1.52	1.61
ROADS AND SITE IMPROVEMENTS	50	2.05	2.44	2.13	2.30
TURBINES AND GENERATORS	60	1.68	1.90	1.72	1.85
GOVERNORS AND EXCITATION SYSTEM	50	2.14	2.25	2.04	2.17
LICENCE RENEWAL	50	2.00	2.00	2.00	2.00
A/C ELECTRICAL POWER SYSTEMS	55	2.03	2.11	1.91	2.03
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	4.58	4.67	4.14	4.62
AUXILIARY STATION PROCESSES	50	2.63	2.19	1.92	2.31
SUPPORT BUILDINGS	65	1.67	1.79	1.60	1.73
SUPPORT BUILDING RENOVATIONS	20	4.98	4.98	4.44	4.44
GRAND RAPIDS					
DAMS, DYKES AND WEIRS	125	0.98	1.01	0.87	0.90
POWERHOUSE	125	0.91	0.92	0.77	0.81
POWERHOUSE RENOVATIONS	40	4.40	2.55	2.28	2.28
SPILLWAY	80	1.30	1.28	1.01	1.15
WATER CONTROL SYSTEMS	65	1.79	1.10	0.95	0.99
ROADS AND SITE IMPROVEMENTS	50	1.68	1.63	1.23	1.21
TURBINES AND GENERATORS	60	1.64	1.82	1.59	1.74
GOVERNORS AND EXCITATION SYSTEM	50	2.13	2.21	2.00	2.13
LICENCE RENEWAL	50	2.00	2.00	2.00	2.00
A/C ELECTRICAL POWER SYSTEMS	55	2.07	1.84	1.57	1.66
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	4.08	3.90	2.99	2.49
AUXILIARY STATION PROCESSES	50	2.62	2.02	1.78	2.29
SUPPORT BUILDINGS	65	1.66	1.69	1.46	1.60
SUPPORT BUILDING RENOVATIONS	20	5.50	5.67	5.00	5.00
COMMUNITY DEVELOPMENT COSTS ***	79	1.16	1.21	1.21	1.21
KETTLE					
DAMS, DYKES AND WEIRS	125	0.86	0.86	0.73	0.78
POWERHOUSE	125	0.87	0.86	0.74	0.79
POWERHOUSE RENOVATIONS	40	4.40	2.75	2.50	2.50
SPILLWAY	80	1.33	1.26	1.03	1.16
WATER CONTROL SYSTEMS	65	1.55	0.99	0.81	0.89
ROADS AND SITE IMPROVEMENTS	50	2.14	2.20	1.99	2.31
TURBINES AND GENERATORS	60	1.48	1.90	1.62	1.73
GOVERNORS AND EXCITATION SYSTEM	50	1.66	2.14	1.84	1.92
LICENCE RENEWAL	50	2.00	2.00	2.00	2.00
A/C ELECTRICAL POWER SYSTEMS	55	2.04	2.04	1.84	1.96
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	4.11	4.20	3.55	3.37
AUXILIARY STATION PROCESSES	50	2.44	1.82	1.57	1.86
SUPPORT BUILDINGS	65	1.46	1.75	1.58	1.70
SUPPORT BUILDING RENOVATIONS	20	5.50	5.50	5.00	5.00

Depreciation Rate Tables (Electric operations) with ASL without Net Salvage cont'd

DEPRECIABLE GROUP (Electric Operations)	Expected Service Life	2014-15 Previous ASL Rate %	2014-15 Approved ASL Rate %	2014-15 ASL Rate % w/o Net Salvage	2015-16 Approved ELG Rate %
LAURIE RIVER					
DAMS, DYKES AND WEIRS	125	3.47	3.20	2.70	2.70
POWERHOUSE	125	4.25	3.89	3.39	3.40
POWERHOUSE RENOVATIONS	40	5.00	5.24	4.76	4.76
SPILLWAY	80	3.88	3.44	2.94	2.96
WATER CONTROL SYSTEMS	65	3.84	3.52	3.02	3.03
ROADS AND SITE IMPROVEMENTS	50	4.01	3.69	3.15	3.23
TURBINES AND GENERATORS	60	4.49	4.11	3.62	3.62
GOVERNORS AND EXCITATION SYSTEM	50	4.70	4.29	3.79	3.81
LICENCE RENEWAL	50	4.55	4.76	4.76	4.76
A/C ELECTRICAL POWER SYSTEMS	55	4.08	3.63	3.12	3.15
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	7.23	6.28	4.87	5.15
AUXILIARY STATION PROCESSES	50	4.30	3.73	3.19	3.31
SUPPORT BUILDINGS	65	3.75	3.36	2.85	2.87
SUPPORT BUILDING RENOVATIONS	20	5.50	5.50	5.00	5.00
JENPEG					
DAMS, DYKES AND WEIRS	125	0.92	0.91	0.80	0.84
POWERHOUSE	125	0.89	0.90	0.78	0.83
POWERHOUSE RENOVATIONS	40	4.40	2.75	2.48	2.48
SPILLWAY	80	1.42	1.35	1.14	1.28
WATER CONTROL SYSTEMS	65	2.02	1.24	0.95	1.07
ROADS AND SITE IMPROVEMENTS	50	2.12	2.07	1.68	1.87
TURBINES AND GENERATORS	60	1.63	1.89	1.59	1.74
GOVERNORS AND EXCITATION SYSTEM	50	2.20	2.20	2.00	2.13
LICENCE RENEWAL	50	2.00	2.00	2.00	2.00
A/C ELECTRICAL POWER SYSTEMS	55	2.05	1.81	1.42	1.53
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	4.53	4.15	3.17	3.39
AUXILIARY STATION PROCESSES	50	2.66	1.92	1.67	2.06
SUPPORT BUILDINGS	65	1.67	1.69	1.46	1.61
SUPPORT BUILDING RENOVATIONS	20	5.50	5.50	5.00	5.00
LAKE WINNIPEG REGULATION					
DAMS, DYKES AND WEIRS	125	0.82	0.82	0.71	0.77
LICENCE RENEWAL	50	2.00	2.02	2.02	2.02
COMMUNITY DEVELOPMENT COSTS	85	0.94	1.18	1.18	1.18
CHURCHILL RIVER DIVERSION					
DAMS, DYKES AND WEIRS	125	0.88	0.88	0.77	0.83
SPILLWAY	80	1.47	1.39	1.18	1.32
WATER CONTROL SYSTEMS	65	2.21	1.17	0.88	1.00
ROADS AND SITE IMPROVEMENTS	50	2.21	2.11	1.63	1.78
LICENCE RENEWAL	50	2.00	2.00	2.00	2.00
A/C ELECTRICAL POWER SYSTEMS	55	2.21	1.88	1.45	1.57
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	4.82	4.78	3.01	2.36
AUXILIARY STATION PROCESSES	50	2.75	1.97	1.70	2.11
SUPPORT BUILDINGS	65	1.69	1.71	1.54	1.66
SUPPORT BUILDING RENOVATIONS	20	5.50	5.50	5.00	5.00
COMMUNITY DEVELOPMENT COSTS	90	0.93	1.07	1.07	1.07

Depreciation Rate Tables (Electric operations) with ASL without Net Salvage cont'd

DEPRECIABLE GROUP (Electric Operations)	Expected Service Life	2014-15 Previous ASL Rate %	2014-15 Approved ASL Rate %	2014-15 ASL Rate % w/o Net Salvage	2015-16 Approved ELG Rate %
LONG SPRUCE					
DAMS, DYKES AND WEIRS	125	0.90	0.90	0.79	0.83
POWERHOUSE	125	0.90	0.90	0.79	0.83
POWERHOUSE RENOVATIONS	40	4.40	2.75	2.50	2.50
SPILLWAY	80	1.43	1.36	1.15	1.30
WATER CONTROL SYSTEMS	65	2.04	0.99	0.66	0.78
ROADS AND SITE IMPROVEMENTS	50	2.10	2.07	1.69	1.87
TURBINES AND GENERATORS	60	1.63	1.88	1.50	1.69
GOVERNORS AND EXCITATION SYSTEM	50	2.19	2.18	1.93	2.08
LICENCE RENEWAL	50	2.00	2.00	2.00	2.00
A/C ELECTRICAL POWER SYSTEMS	55	2.09	1.79	1.37	1.51
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	4.37	4.37	3.81	3.87
AUXILIARY STATION PROCESSES	50	2.63	1.60	1.30	1.53
SUPPORT BUILDINGS	65	1.69	1.69	1.51	1.64
SUPPORT BUILDING RENOVATIONS	20	5.50	5.50	4.90	4.90
LIMESTONE					
DAMS, DYKES AND WEIRS	125	0.90	0.91	0.81	0.85
POWERHOUSE	125	0.91	0.91	0.81	0.85
POWERHOUSE RENOVATIONS	40	4.40	2.75	2.50	2.50
SPILLWAY	80	1.45	1.37	1.20	1.37
WATER CONTROL SYSTEMS	65	2.17	1.39	1.16	1.28
ROADS AND SITE IMPROVEMENTS	50	2.17	2.14	1.80	2.03
TURBINES AND GENERATORS	60	1.68	1.90	1.63	1.81
GOVERNORS AND EXCITATION SYSTEM	50	2.17	2.15	1.80	1.96
LICENCE RENEWAL	50	2.00	2.00	2.00	2.00
A/C ELECTRICAL POWER SYSTEMS	55	2.17	1.89	1.59	1.73
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	4.67	4.16	3.16	3.48
AUXILIARY STATION PROCESSES	50	2.71	1.78	1.47	1.80
SUPPORT BUILDINGS	65	1.68	1.71	1.48	1.63
SUPPORT BUILDING RENOVATIONS	20	5.50	5.50	4.89	4.89
WUSKWATIM					
DAMS, DYKES AND WEIRS	125	0.88	0.91	0.82	0.87
POWERHOUSE	125	0.88	0.91	0.83	0.87
POWERHOUSE RENOVATIONS	40	4.40	2.75	2.50	2.50
SPILLWAY	80	1.47	1.36	1.24	1.46
WATER CONTROL SYSTEMS	65	2.20	1.68	1.52	1.62
ROADS AND SITE IMPROVEMENTS	50	2.20	2.19	1.99	2.32
TURBINES AND GENERATORS	60	1.69	1.83	1.66	1.78
GOVERNORS AND EXCITATION SYSTEM	50	2.20	2.19	1.98	2.12
A/C ELECTRICAL POWER SYSTEMS	55	2.20	1.99	1.81	1.92
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	4.78	4.24	3.83	4.39
AUXILIARY STATION PROCESSES	50	2.75	2.13	1.93	2.93
SUPPORT BUILDINGS	65	1.69	1.69	1.53	1.64
SUPPORT BUILDING RENOVATIONS	20	5.50	5.50	5.00	5.00
INFRASTRUCTURE SUPPORTING GENERATION					
PROVINCIAL ROADS	50	2.30	2.49	2.02	2.21
TOWN SITE BUILDING	55	1.71	2.12	1.93	2.03
TOWN SITE BUILDINGS RENOVATIONS	20	5.94	5.30	5.00	5.00
TOWN SITE OTHER INFRASTRUCTURE	45	2.49	3.11	2.77	2.93

Depreciation Rate Tables (Electric operations) with ASL without Net Salvage cont'd

DEPRECIABLE GROUP (Electric Operations)	Expected Service Life	2014-15 Previous ASL Rate %	2014-15 Approved ASL Rate %	2014-15 ASL Rate % w/o Net Salvage	2015-16 Approved ELG Rate %
THERMAL GENERATION					
BRANDON UNIT 5 (COAL)					
POWERHOUSE	75	3.87	4.52	4.52	4.50
POWERHOUSE RENOVATIONS	40	10.00	15.88	15.88	15.88
ROADS AND SITE IMPROVEMENTS	50	4.56	5.37	5.37	5.36
THERMAL TURBINES AND GENERATORS	60	5.03	5.73	5.73	5.72
GOVERNORS AND EXCITATION SYSTEM	50	5.07	5.51	5.51	5.52
STEAM GENERATOR AND AUXILIARIES	60	3.93	4.06	4.06	4.05
LICENCE RENEWAL	50	10.00	14.81	14.81	14.81
A/C ELECTRICAL POWER SYSTEMS	55	4.06	4.65	4.65	4.64
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	5.41	4.44	4.44	4.41
AUXILIARY STATION PROCESSES	50	4.67	5.36	5.36	5.37
SUPPORT BUILDINGS	65	4.25	5.97	5.97	5.97
SUPPORT BUILDING RENOVATIONS	20	10.00	16.67	16.67	16.67
BRANDON UNITS 6 AND 7					
POWERHOUSE	75	1.65	1.38	1.22	1.26
POWERHOUSE RENOVATIONS	40	4.40	2.72	2.46	2.46
THERMAL TURBINES AND GENERATORS	60	2.12	1.70	1.49	1.64
GOVERNORS AND EXCITATION SYSTEM	50	2.20	2.20	2.00	2.13
COMBUSTION TURBINE	25	4.05	3.87	3.18	3.66
LICENCE RENEWAL	50	2.00	2.00	2.00	2.00
COMBUSTION TURBINE OVERHAULS	15	11.00	7.33	6.67	6.67
A/C ELECTRICAL POWER SYSTEMS	55	2.12	1.88	1.65	1.78
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	4.58	4.52	4.00	4.63
AUXILIARY STATION PROCESSES	50	2.64	1.91	1.66	2.10
SELKIRK					
POWERHOUSE	75	0.93	0.76	0.76	0.79
POWERHOUSE RENOVATIONS	40	4.00	2.45	2.45	2.45
ROADS AND SITE IMPROVEMENTS	50	1.35	1.34	1.34	1.42
THERMAL TURBINES AND GENERATORS	60	1.46	1.09	1.09	1.18
GOVERNORS AND EXCITATION SYSTEM	50	2.00	1.13	1.13	1.30
STEAM GENERATOR AND AUXILIARIES	60	1.34	1.49	1.49	1.66
LICENCE RENEWAL	50	2.00	2.00	2.00	2.00
A/C ELECTRICAL POWER SYSTEMS	55	1.21	1.06	1.06	1.03
INSTRUMENTATION, CONTROL AND D/C SYSTEMS	25	2.41	2.11	2.11	2.40
AUXILIARY STATION PROCESSES	50	1.64	1.19	1.19	1.44
SUPPORT BUILDINGS	65	1.06	1.06	1.06	1.13
SUPPORT BUILDING RENOVATIONS	20	5.00	5.00	5.00	5.00

Depreciation Rate Tables (Electric operations) with ASL without Net Salvage cont'd

DEPRECIABLE GROUP (Electric Operations)	Expected Service Life	2014-15 Previous ASL Rate %	2014-15 Approved ASL Rate %	2014-15 ASL Rate % w/o Net Salvage	2015-16 Approved ELG Rate %
DIESEL GENERATION					
BUILDINGS	25	2.57	3.15	2.78	3.17
BUILDING RENOVATIONS	15	5.14	6.67	6.67	6.67
ENGINES AND GENERATORS - OVERHAULS	4	20.00	25.00	25.00	25.00
ENGINES AND GENERATORS	22	1.88	2.24	2.24	2.73
ACCESSORY STATION EQUIPMENT	20	3.07	3.70	3.38	3.67
FUEL STORAGE AND HANDLING	25	2.28	2.37	2.09	2.60
TRANSMISSION					
ROADS, TRAILS AND BRIDGES	50	2.51	2.19	1.96	2.18
METAL TOWERS AND CONCRETE POLES	85	1.51	1.54	1.16	1.23
POLES AND FIXTURES	55	2.49	2.48	1.59	1.80
GROUND LINE TREATMENT	10	10.00	10.00	10.00	10.00
OVERHEAD CONDUCTOR AND DEVICES	80	1.62	1.27	1.02	1.10
UNDERGROUND CABLE AND DEVICES	45	2.23	1.96	1.63	1.81
COMMUNITY DEVELOPMENT COSTS ***	79	1.27	1.27	1.27	1.27
SUBSTATIONS					
BUILDINGS	65	1.49	1.47	1.37	1.46
BUILDING RENOVATIONS	20	5.00	5.00	5.00	5.00
ROADS, STEEL STRUCTURES AND CIVIL SITE WORK	50	2.10	1.95	1.67	1.76
POLES AND FIXTURES	45	3.25	3.01	1.99	2.39
POWER TRANSFORMERS	50	2.21	2.44	2.00	2.43
OTHER TRANSFORMERS	50	3.09	2.29	1.86	2.26
INTERRUPTING EQUIPMENT	50	2.41	2.52	2.05	2.31
OTHER STATION EQUIPMENT	45	2.54	2.47	1.98	2.20
ELECTRONIC EQUIPMENT AND BATTERIES	25	4.76	3.81	3.28	3.90
SYNCHRONOUS CONDENSERS AND UNIT TRANSFORMER	65	1.68	1.80	1.40	1.52
SYNCHRONOUS CONDENSER OVERHAULS	15	7.43	7.15	5.58	5.58
HVDC CONVERTER EQUIPMENT	30	4.13	3.22	2.47	2.61
HVDC SERIALIZED EQUIPMENT	30	4.18	3.04	2.24	2.07
HVDC ACCESSORY STATION EQUIPMENT	36	2.85	2.98	2.40	2.67
HVDC ELECTRONIC EQUIPMENT AND BATTERIES	25	4.66	3.10	2.49	2.27
DISTRIBUTION					
CONCRETE DUCTLINE AND MANHOLES	75	2.29	2.23	2.09	2.25
CONCRETE DUCTLINE AND MANHOLE REFURBISHMENT	30	2.08	3.66	3.47	3.70
METAL TOWERS	60	1.99	2.10	1.62	1.87
POLES AND FIXTURES	65	2.10	1.96	1.19	1.58
GROUND LINE TREATMENT	12	9.58	7.39	7.39	7.39
OVERHEAD CONDUCTOR AND DEVICES	60	1.98	2.24	1.40	1.80
UNDERGROUND CABLE AND DEVICES - 66 KV	60	1.48	1.72	1.63	2.07
UNDERGROUND CABLE AND DEVICES - PRIMARY	60	1.69	1.70	1.60	1.83
UNDERGROUND CABLE AND DEVICES - SECONDARY	44	2.21	2.27	2.12	2.31
SERIALIZED EQUIPMENT - OVERHEAD	45	2.86	2.28	1.84	2.10
DSC - HIGH VOLTAGE TRANSFORMERS	50	2.19	2.34	2.02	2.34
SERIALIZED EQUIPMENT - UNDERGROUND	42	2.62	2.60	2.13	2.40
ELECTRONIC EQUIPMENT	10	10.00	10.53	10.53	10.53
SERVICES	35	4.38	2.92	1.50	1.89
STREET LIGHTING	45	3.04	2.56	2.02	2.20

Depreciation Rate Tables (Electric operations) with ASL without Net Salvage cont'd

DEPRECIABLE GROUP (Electric Operations)	Expected Service Life	2014-15 Previous ASL Rate %	2014-15 Approved ASL Rate %	2014-15 ASL Rate % w/o Net Salvage	2015-16 Approved ELG Rate %
METERS					
METERS - ELECTRONIC	15	6.10	9.61	9.61	10.52
METERS - ANALOG	26	13.54	3.84	3.84	4.21
METERING EXCHANGES	15	6.67	6.67	6.67	6.67
METERING TRANSFORMERS	50	2.20	1.80	1.80	2.12
COMMUNICATION					
BUILDINGS	65	1.67	1.41	1.30	1.48
BUILDING RENOVATIONS	20	5.67	4.95	4.58	4.58
BUILDING - SYSTEM CONTROL CENTRE	75	1.68	1.39	1.30	1.40
COMMUNICATION TOWERS	60	1.82	1.82	1.71	2.01
FIBRE OPTIC AND METALLIC CABLE	35	3.06	3.12	2.97	3.45
CARRIER EQUIPMENT	20	7.68	4.74	4.34	4.90
OPERATIONAL IT EQUIPMENT	5	22.97	21.00	20.00	20.00
MOBILE RADIO, TELEPHONE AND VIDEO CONFERENCIN(	8	10.24	18.56	16.64	16.64
OPERATIONAL DATA NETWORK	8	14.10	13.13	12.50	12.50
POWER SYSTEM CONTROL	15	11.16	5.63	5.14	5.50
MOTOR VEHICLES					
PASSENGER VEHICLES	11	11.09	7.03	7.03	7.59
LIGHT TRUCKS	12	7.85	7.16	7.16	7.54
HEAVY TRUCKS	19	5.83	4.68	4.68	5.01
CONSTRUCTION EQUIPMENT	23	5.27	2.77	2.77	3.23
LARGE SOFT-TRACK EQUIPMENT	27	4.28	2.96	2.96	3.79
TRAILERS	35	1.94	2.38	2.38	2.91
MISCELLANEOUS VEHICLES	13	5.93	4.90	4.90	6.60
BUILDINGS					
BUILDINGS - GENERAL	65	1.59	1.65	1.54	1.73
BUILDING RENOVATIONS	20	7.14	5.59	5.00	5.00
BUILDING - 360 PORTAGE - CIVIL	100	1.00	1.00	1.00	1.06
BUILDING - 360 PORTAGE - ELECTRO/MECHANICAL	45	2.21	2.23	2.23	2.56
LEASEHOLD IMPROVEMENTS - SONY PLACE	10	10.00	10.00	10.00	10.00
GENERAL EQUIPMENT					
TOOLS, SHOP AND GARAGE EQUIPMENT	15	7.74	6.48	6.48	6.48
COMPUTER EQUIPMENT	5	28.48	20.00	20.00	20.00
OFFICE FURNITURE AND EQUIPMENT	20	4.81	5.00	5.00	5.00
HOT WATER TANKS	6	21.20	16.67	16.67	16.67
EASEMENTS					
EASEMENTS	75	1.28	1.33	1.33	1.33
COMPUTER SOFTWARE AND DEVELOPMENT					
COMPUTER DEVELOPMENT - MAJOR SYSTEMS	11	9.47	8.75	8.75	8.82
COMPUTER DEVELOPMENT - SMALL SYSTEMS	10	10.00	9.13	9.13	9.13
COMPUTER SOFTWARE - GENERAL	5	19.76	20.00	20.00	20.00
COMPUTER SOFTWARE - COMMUNICATION/OPERATION/	5	13.93	27.31	27.31	27.31
OPERATIONAL SYSTEM MAJOR SOFTWARE - EMS/SCADA	7	23.35	8.06	8.06	9.33

Depreciation Rate Tables (Electric operations) with ASL without Net Salvage cont'd

DEPRECIABLE GROUP (Electric Operations)	Expected Service Life	2014-15 Previous* ASL Rate %	2014-15 Approved ASL Rate %	2014-15 ASL Rate % w/o Net Salvage	2015-16 Approved ELG Rate %
WUSKWATIM POWER LIMITED PARTNERSHIP (WPLP)					
HYDRAULIC GENERATION					
WPLP - DAMS, DYKES AND WEIRS	125		0.91	0.83	0.87
WPLP - POWERHOUSE	125		0.91	0.83	0.87
WPLP - POWERHOUSE RENOVATIONS	40		2.75	2.50	2.50
WPLP - SPILLWAY	80		1.37	1.24	1.46
WPLP - WATER CONTROL SYSTEMS	65		1.68	1.52	1.62
WPLP - ROADS AND SITE IMPROVEMENTS	50		2.19	1.99	2.32
WPLP - TURBINES AND GENERATORS	60		1.84	1.67	1.79
WPLP - GOVERNORS AND EXCITATION SYSTEM	50		2.20	1.99	2.12
WPLP - A/C ELECTRICAL POWER SYSTEMS	55		1.99	1.80	1.91
WPLP - INSTRUMENTATION, CONTROL AND D/C SYSTEM	25		4.36	3.93	4.51
WPLP - AUXILIARY STATION PROCESSES	50		2.17	1.97	2.75
WPLP - SUPPORT BUILDINGS	65		1.69	1.53	1.65
WPLP - SUPPORT BUILDING RENOVATIONS	20		5.50	5.00	5.00
WPLP - OPERATIONAL EMPLOYMENT FUND	95		0.97	0.97	0.97
SUBSTATIONS					
WPLP - BUILDINGS	65		1.62	1.54	1.64
WPLP - ROADS, STEEL STRUCTURES AND CIVIL SITE WOI	50		2.20	1.99	2.13
WPLP - POWER TRANSFORMERS	50		2.28	1.98	3.11
WPLP - INTERRUPTING EQUIPMENT	50		2.29	1.98	2.54
WPLP - OTHER STATION EQUIPMENT	45		2.55	2.20	2.56
WPLP - ELECTRONIC EQUIPMENT AND BATTERIES	25		4.33	3.90	5.23
COMMUNICATION					
WPLP - FIBRE OPTIC AND METALLIC CABLE	35		2.95	2.83	3.57
WPLP - CARRIER EQUIPMENT	20		4.98	4.71	5.88
MOTOR VEHICLES					
WPLP - HEAVY TRUCKS	19		2.43	2.43	2.75
WPLP - CONSTRUCTION EQUIPMENT	23		3.61	3.61	4.44
WPLP - TRAILERS	35		2.45	2.45	3.12
WPLP - MISCELLANEOUS VEHICLES	13		6.38	6.38	9.42
GENERAL EQUIPMENT					
WPLP - COMPUTER EQUIPMENT	5		15.66	15.66	15.66

* Depreciation rates were not established in the 2010 Depreciation Study

Depreciation Rate Tables (Electric operations) with ASL without Net Salvage cont'd

DEPRECIABLE GROUP (Electric Operations)	Expected Service Life	2014-15 Previous* ASL Rate %	2014-15 Approved ASL Rate %	2014-15 ASL Rate % w/o Net Salvage	2015-16 Approved ELG Rate %
WPLP INTANGIBLE ASSETS					
TRANSMISSION					
WPLP - ROADS, TRAILS AND BRIDGES	50		2.18	1.98	2.20
WPLP - METAL TOWERS AND CONCRETE POLES	85		1.47	1.17	1.24
WPLP - POLES AND FIXTURES	55		2.45	1.80	2.10
WPLP - OVERHEAD CONDUCTOR AND DEVICES	80		1.43	1.24	1.32
WPLP - TRANSMISSION DEVELOPMENT FUND	79		1.26	1.26	1.26
SUBSTATIONS					
WPLP - BUILDINGS	65		1.62	1.54	1.64
WPLP - ROADS, STEEL STRUCTURES AND CIVIL SITE WOI	50		2.20	1.99	2.13
WPLP - POWER TRANSFORMERS	50		2.28	1.98	3.12
WPLP - OTHER TRANSFORMERS	50		2.27	1.96	2.52
WPLP - INTERRUPTING EQUIPMENT	50		2.29	1.98	2.54
WPLP - OTHER STATION EQUIPMENT	45		2.55	2.20	2.57
WPLP - ELECTRONIC EQUIPMENT AND BATTERIES	25		4.33	3.90	5.23
DISTRIBUTION					
WPLP - POLES AND FIXTURES	65		2.12	1.52	2.20
WPLP - OVERHEAD CONDUCTOR AND DEVICES	60		2.30	1.65	2.65
WPLP - UNDERGROUND CABLE AND DEVICES - PRIMARY	60		1.75	1.67	1.94
WPLP - SERIALIZED EQUIPMENT - UNDERGROUND	42		2.73	2.36	2.75
COMMUNICATION					
WPLP - FIBRE OPTIC AND METALLIC CABLE	35		2.95	2.83	3.57
WPLP - CARRIER EQUIPMENT	20		4.98	4.71	5.88
WPLP - MOBILE RADIO, TELEPHONE AND CONFERENCIN	8		13.62	12.85	12.85
WPLP - OPERATIONAL DATA NETWORK	8		12.66	11.89	11.89
EASEMENTS	75		1.33	1.33	1.33

* Depreciation rates were not established in the 2010 Depreciation Study

Section:	Tab 5: Schedule 5.1.6 Appendix 5.6 pg.7	Page No.:	PUB/MH I-46 (a) & (b)
Topic:	Financial Results & Forecasts		
Subtopic:	Depreciation & Amortization		
Issue:	Depreciation Rate Changes		

PREAMBLE TO IR (IF ANY):

Please refile PUB/MH I-46(b) excluding net salvage from the ASL based rates.

QUESTION:

To test the impact of an ASL-based approach to depreciation.

RATIONALE FOR QUESTION:

RESPONSE:

The following schedule provides a comparison, for the 2015/16 and 2016/17 fiscal years, of the applied for ELG depreciation with the depreciation expense which would result from the continuation of CGAAP ASL based depreciation rates and the removal of any provision for net salvage. Please note that the CGAAP ASL without salvage depreciation figures presented in this schedule are not IFRS compliant.

Please see the response to PUB/MH-II-21b and PUB/MH-II-21c for a discussion regarding the impacts associated with using the CGAAP ASL method of depreciation for rate setting purposes.

MANITOBA HYDRO
DEPRECIATION AND AMORTIZATION EXPENSE
COMPARISON OF ELG AND ASL WITHOUT SALVAGE (000's)

	Schedule 5.1.6		CGAAP ASL without Net Salvage *		Difference	
	2015/16 Forecast ELG	2016/17 Forecast ELG	2015/16 Forecast ASL	2016/17 Forecast ASL	2015/16 Forecast	2016/17 Forecast
Generation						
Hydraulic Generating Stations	92,265	96,041	84,781	87,713	7,484	8,328
Thermal Generating Stations	15,755	15,856	14,138	14,195	1,617	1,661
Demand Side Management	34,957	37,501	34,957	37,501	0	0
Diesel Generating Stations	2,557	2,111	2,320	1,874	237	237
Wuskwatim	26,984	27,082	24,136	24,351	2,848	2,731
Amortization of Contributions	(1,146)	(1,146)	(1,146)	(1,146)	(0)	(0)
	$ 171,373	$ 177,446	$ 159,186	$ 164,488	$ 12,187	$ 12,958
Transmission						
Transmission	13,369	14,367	12,684	13,596	685	771
Amortization of Contributions	(3,054)	(3,059)	(3,297)	(3,302)	243	243
	$ 10,315	$ 11,308	$ 9,387	$ 10,294	$ 928	$ 1,014
Stations						
Substations	85,735	90,177	77,584	81,468	8,151	8,709
Transformers	1,597	1,828	1,514	1,768	83	60
Amortization of Contributions	(4,402)	(4,402)	(4,433)	(4,547)	31	145
	$ 82,930	$ 87,603	$ 74,665	$ 78,689	$ 8,265	$ 8,914
Distribution						
Subtransmission Lines	6,948	7,401	5,390	5,763	1,558	1,638
Distribution Lines	56,989	60,951	47,601	50,919	9,388	10,032
Meters & Transformers	3,281	3,404	2,952	3,062	329	342
Amortization of Contributions	(6,409)	(7,009)	(6,408)	(7,008)	(1)	(1)
	$ 60,809	$ 64,747	$ 49,535	$ 52,736	$ 11,274	$ 12,011
Other						
Communications	17,765	18,206	16,141	16,505	1,624	1,701
Motor Vehicles	11,819	12,226	10,730	11,089	1,089	1,137
Structures & Improvements	8,800	9,557	8,112	8,809	688	748
General Equipment	16,780	16,797	16,780	16,796	0	1
Computer Development	18,487	20,816	18,248	20,540	239	276
Conawapa	-	7,711	-	7,711	-	0
Affordable Energy Fund	4,290	1,509	4,290	1,509	0	(0)
Miscellaneous	2,652	3,269	2,385	3,003	266	266
Corporate Allocation	(1,850)	(1,853)	(1,583)	(1,586)	(267)	(267)
Target Adjustment	(3,305)	(6,938)	(3,030)	(6,324)	(275)	(614)
	$ 75,439	$ 81,300	$ 72,074	$ 78,053	$ 3,365	$ 3,248
Total D & A Expense	$ 400,866	$ 422,404	$ 364,847	$ 384,260	$ 36,019	$ 38,145

* The ASL no Salvage figures presented for 2015/16 & 2016/17 are not IFRS compliant

Section:	Tab 5: Appendix 5.6 Attachment 2	Page No.:	PUB/MH I-40a, b
Topic:	Financial Results & Forecasts		
Subtopic:	Depreciation & Amortization		
Issue:	Impact on Revenue Requirement of use of ASL vs ELG		

PREAMBLE TO IR (IF ANY):

The analysis in PUB/MH I-40 b appears to show that depreciation expense would be higher under ASL in 2021/22 than using ELG.

QUESTION:

Please refile the analysis by removing net salvage from the calculated depreciation costs and providing a comparison between ELG and the adjusted ASL rates.

RATIONALE FOR QUESTION:

To understand the implications for rate-setting purposes of using ASL rates rather than ELG as proposed by MH.

RESPONSE:

The following table provides a summary of the forecast average Property, Plant and Equipment in service, and a comparison of the associated depreciation expense for the 2021/22 fiscal year calculated using ELG no Salvage (IFRS) and CGAAP ASL no Salvage depreciation rates. Please note that the depreciation associated with the WPLP is not included in either Appendix 5.6, Attachment 2, page vii, or this response. Please also note that the CGAAP ASL no Salvage depreciation figures provided in this response are not IFRS compliant. In addition, please see the response to PUB/MH-II-21b and PUB/MH II-21c for a discussion regarding the impacts associated with using the CGAAP ASL method of depreciation for rate-setting purposes.

PLANT GROUP	FORECAST AVERAGE PLANT IN SERVICE 2021/22 $ 000's	FORECAST DEPRECIATION EXPENSE ELG NO SALVAGE (IFRS) 2021/22 %'s	$ 000's	FORECAST DEPRECIATION EXPENSE CGAAP ASL NO SALVAGE 2021/22 %'s	$ 000's	DIFFERENCE IN FORECAST DEPRECIATION EXPENSE ELG VS. CGAAP ASL (NO SALVAGE) 2021/22 %'s	$ 000's
MANITOBA HYDRO							
Generation							
Hydro	$ 7 950 831	1.59	$ 126 084	1.49	$ 118 796	0.09	$ 7 288
Thermal	452 862	3.40	15 414	3.19	14 467	0.21	947
Diesel	52 650	3.34	1 756	2.93	1 544	0.40	212
Transmission	3 516 821	1.28	45 093	1.11	39 087	0.17	6 006
Substations	7 122 683	2.37	168 690	2.16	153 510	0.21	15 180
Distribution	4 266 096	2.01	85 614	1.72	73 394	0.29	12 220
General	1 991 241	5.06	100 726	4.82	95 954	0.24	4 772
Manitoba Hydro - Total Plant in Service	**$ 25 353 184**	**2.14**	**$ 543 377**	**1.96**	**$ 496 752**	**0.18**	**$ 46 625**
KEEYASK HYDROPOWER LIMITED PARTNERSHIP							
Generation							
Hydro	6 048 540	1.33	80 628	1.22	73 566	0.12	7 062
Transmission	19 839	1.36	270	1.24	246	0.12	24
Substations	21 294	1.36	290	1.24	264	0.12	26
Distribution	2 467	1.38	34	1.26	31	0.12	3
KHLP - Total Plant in Service	**$ 6 092 140**	**1.33**	**$ 81 222**	**1.22**	**$ 74 107**	**0.12**	**$ 7 115**
Total Plant in Service	**$ 31 445 324**	**1.99**	**$ 624 599**	**1.82**	**$ 570 859**	**0.17**	**$ 53 740**

* The CGAAP ASL no Salvage depreciation figures provided in this schedule are not IFRS compliant.

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Section:		Page No.:	
Topic:	Financial Results and Forecast		
Subtopic:	Depreciation		
Issue:	Treatment of Gains and Losses on Asset Retirement		

PREAMBLE TO IR (IF ANY):

MH has stated that:

> *"Currently under CGAAP, Manitoba Hydro follows a common industry practice for regulated utilities whereby asset retirement gains and losses are recorded in the accumulated depreciation account for the retired asset's respective component group. Such gains and losses are then factored into future depreciation rate changes for the component group and are recognized in net income over time, as part of future years' depreciation expense."*

QUESTION:

a) Please indicate whether the existing regulatory practice could continue for rate setting and financial reporting purposes. Discuss the implications related to Financial Reporting.

b) Please file Manitoba Hydro's external auditor's opinion/report(s) related to the continuation of the current accounting practice.

RATIONALE FOR QUESTION:

To understand the implications of retaining an existing accounting practice.

RESPONSE:

a) The existing regulatory practice whereby asset retirement gains and losses are recorded in the accumulated depreciation account for the retired asset's respective component group and then factored into future depreciation rate changes for the group may be continued for rate setting purposes if ordered by the PUB, but cannot be continued for financial reporting purposes under IFRS. IFRS specifically requires gains and losses on the retirement of an asset to be recognized in net income immediately. As per IFRS standard IAS 16, Property, plant and Equipment:

68 *The gain or loss arising from the derecognition of an item of property, plant and equipment shall be included in profit or loss when the item is derecognized*

If the PUB directed the continuation of the current CGAAP practice of recording asset retirement gains and losses in the accumulated depreciation account for rate-setting purposes upon the adoption of IFRS, Manitoba Hydro would be required to establish a regulatory deferral account for financial reporting to capture the difference in the accounting for gains and losses between the rate-setting and the financial reporting purposes. This accounting treatment would be necessary for compliance with the requirements of IFRS standard *IFRS 14 – Regulatory Deferral Accounts*.

In addition, as further outlined in the response to PUB/MH-II-21c, if the recognition of asset retirement gains and losses is different for rate-setting purposes from the method used for financial reporting, Manitoba Hydro will be required to incur the additional administrative costs of having to maintain two separate set of asset sub-ledgers to capture the thousands of transactions that occur for PP&E assets over the course of a year. Notably, Manitoba Hydro expects asset retirement gains and losses to be lower when using the ELG method under IFRS.

b) Manitoba Hydro has not engaged its auditor Ernst & Young to provide an opinion/report(s) related to the continuation of the current accounting practice of recording asset retirement gains and losses in accumulated depreciation and as such, a report does not exist.

Section:	Tab 5; Appendix 5.6 Schedule 1	Page No.:	PUB/MH I-45a
Topic:	Financial Result & Forecasts		
Subtopic:	Depreciation Expense		
Issue:	Sustaining Capital Spending		

PREAMBLE TO IR (IF ANY):

The asset retirement information filed in the depreciation study is illustrative only and does not reflect Manitoba Hydro's experience. Asset retirement information was filed as Manitoba Hydro Exhibit #54 from the 2012 GRA.

QUESTION:

Please file an update to MH Exhibit #54 reflecting Manitoba Hydro's asset retirements and indicate to which extent each of the asset retired was over- or under-depreciated.

RATIONALE FOR QUESTION:

To understand the implications of asset retirements in assessing the depreciation study.

RESPONSE:

The following table provides the accumulated depreciation balance and loss experienced on disposition of the Dams, Dykes and Weirs assets retired at age intervals 54.5 through 66.5.

As these retirements occurred prior to reaching the average service life of the account, the assets were not fully depreciated at the time of retirement, resulting in losses on disposition equal to approximately 30% of the retirement value of the assets. Under ELG, such losses are expected to be significantly smaller as assets are depreciated over their individual service lives.

Age At Beginning of Interval	Retirements During Age Interval	Hydraulic Generating Facility	Year Retired	Year Installed	Book Accumulated Depreciation at Time of Retirement	Loss on Disposition	Note
54.5	$ 192,434	Seven Sisters	1987	1932	$ 125,811	$ 66,623	(1)
60.5	175,771	Great Falls	1990	1929	117,656	58,115	(2)
61.5	44,894	Great Falls	1989	1927	32,733	12,161	(3)
62.5	19,841	Great Falls	1990	1927	13,735	6,106	(2)
65.5	155,106	Great Falls	1989	1923	114,960	40,146	(3)
66.5	283,771	Great Falls	1990	1923	209,429	74,342	(2)
	$ 871,817				$ 614,324	$ 257,493	

Nature of work triggering asset retirement:
(1) Rehabilitation of concrete for overflow and non-overflow dams
(2) Rehabilitation of concrete and structural steel for overflow and non-overflow dams
(3) Bridge removal

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M A N I T O B A	**Order No. 43/13**
THE PUBLIC UTILITIES BOARD ACT	**April 26, 2013**

Before: Régis Gosselin, B.A., M.B.A., C.G.A., Chair
Raymond Lafond, B.A., C.M.A., F.C.A., Member
Larry Soldier, Member

FINAL ORDER WITH RESPECT TO
MANITOBA HYDRO'S 2012/13 AND 2013/14
GENERAL RATE APPLICATION

6. That Manitoba Hydro file with the Board an International Financial Reporting Standards status update report prior to the next General Rate Application that will provide the Board options available for rate-setting purposes.

7. That Manitoba Hydro complete and file with the Board an Asset Condition Assessment Study no later than the filing of the next updated depreciation study with the Board.

8. That Manitoba Hydro file updated depreciation rates and schedules based on an International Financial Reporting Standards-compliant Average Service Life methodology with the next General Rate Application.

9. That Manitoba Hydro file with the Board, with the next General Rate Application, a chart showing a comparison of the impact on its Integrated Financial Forecast (i.e. 'Budget') of asset depreciation pursuant to the Average Service Life methodology (without net salvage) and the Equal Life Group methodology (without net salvage), applying both methodologies to all planned major capital additions.

10. That Manitoba Hydro file, with its next General Rate Application, a detailed quantitative and probabilistic risk assessment and review of all of its operating and financial risks in order to allow the Board to assess the adequacy of the reserves. Commercially sensitive information in the report is to be redacted from the public version and filed in confidence with the Board.

11. That Manitoba Hydro file with the Board any negotiated agreements or changes with respect to the Wuskwatim Power Limited Partnership when finalized, and detail the impacts on Manitoba Hydro's operating results and rates.

12. That Manitoba Hydro's revenue requirements are determined based on the level of Demand-Side Management spending as set out in Manitoba Hydro's 2011 Power Smart report, i.e., $34 million for 2012/13 and $35 million for 2013/14, for a total of $69 million. To the extent Manitoba Hydro's spending on Demand-Side Management in the test years, including the Affordable Energy Fund and the Lower Income Energy Efficiency Program, falls below $69 million, Manitoba Hydro shall establish a deferral account for the discrepancy, the disposition of which the Board will consider at the next General Rate Application.

13. That Manitoba Hydro's proposed changes to the Curtailable Rate Program **BE AND ARE HEREBY APPROVED ON AN INTERIM BASIS**, to be reviewed by the Board at a General Rate Application to follow the Needs For And Alternatives To (NFAT) hearing with respect to Manitoba Hydro's Preferred Development Plan.

Manitoba Hydro

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May 6, 2014

THE PUBLIC UTILITIES BOARD OF MANITOBA
400-330 Portage Avenue
Winnipeg, Manitoba
R3C 0C4

ATTENTION: Mr. H. Singh, Board Secretary and Executive Director

Dear Mr. Gosselin:

RE: Directive 8 and 9 of Order 43/13 re: Average Service Life and Equal Life Group Methods of Depreciation

As part of its 2012/13 & 2013/14 General Rate Application ("GRA"), Manitoba Hydro filed its most recent depreciation study, which included International Financial Rreporting Standards ("IFRS") compliant depreciation rates. Manitoba Hydro will transition to IFRS for its fiscal year beginning April 1, 2015, with comparative information required for the previous fiscal year 2014/15. Upon conversion to IFRS, Manitoba Hydro is moving from the Average Service Life ("ASL") method of depreciation to the Equal Life Group ("ELG") method for finanicial reporting purposes.

On April 26, 2013, the Public Utilities Board ("PUB") issued Order 43/13 with respect to Manitoba Hydro's 2012/13 & 2013/14 GRA. Directives 8 and 9 of this Order are related to the use of the ASL and ELG methods of depreciation, as follows:

> *8. That Manitoba Hydro file updated depreciation rates and schedules based on an International Financial Reporting Standards-compliant Average Service Life methodology with the next General Rate Application.*
>
> *9. That Manitoba Hydro file with the Board, with the next General Rate Application, a chart showing a comparison of the impact on its Integrated Financial Forecast (i.e. 'Budget') of asset depreciation pursuant to the Average Service Life methodology (without net salvage) and the Equal Life Group methodology (without net salvage), applying both methodologies to all planned major capital additions.*

Manitoba Hydro is of the view that the ELG methodology will produce an equivalent annual depreciation expense as compared to an IFRS compliant ASL methodology applied to more asset components.

To respond to Directives 8 and 9 of Order 43/13, Manitoba Hydro has developed an approach that will provide a comparison of the two IFRS compliant depreciation methodologies in the timeframe directed given the size of its property, plant and equipment (approximately $19 billion as at March 31, 2014). As part of this approach, Manitoba Hydro will first develop new asset component groups for each significant asset category (eg. generation, transmission, sub-stations) consistent with an IFRS compliant ASL methodology. The expanded list of asset component groups will be applied to a representative sample of physical facilities. Historical asset records will be analyzed for the selected sample in order to allocate vintaged asset costs and historical retirements between the existing and new components. The results of the asset re-componization from the selected sample will then be extrapolated to the entire asset category.

In developing the IFRS compliant ELG methodology, Manitoba Hydro required approximately two years to review the past 70 years of historical work to be in a position to quantify and vintage the existing asset costs that were allocated between new and existing components. An IFRS compliant ASL method will require additional component groups, and as such the effort required will be significant. By extrapolating the results of a representative sample over each asset category, Manitoba Hydro will be in a position to respond to the directive by Manitoba Hydro's next GRA.

Rather than replicating a full depreciation study, this approach will identify additional asset components for each asset category, which will then be used to produce a set of IFRS compliant ASL depreciation rates that will be used to provide a comparison to the ELG depreciation expense, as sought in Directives 8 and 9 of Order 43/13.

For example, additional components will be identified for hydro electric generating stations. A representative sample of generating station assets will then be selected, analyzed and re-componentized. A representative sample of generating stations would include an older plant, mid-life plant, and a newer plant, such as Wuskwatim. The total cost for each new and existing component will be determined for each representative sample through a review of historic asset records in order to allocate vintaged asset costs and historical retirements between the existing and new components. The total cost by asset component group will be determined by extrapolating the results of the analysis performed on the selected sample for each of the additional generating stations, resulting in the total original cost as of March 31, 2013 being re-allocated to a new set of asset component groups for all generating stations. New depreciation rates will be determined for the new components, and an annual expense impact will be estimated for all generating stations. The annual total depreciation expense for generating stations under the IFRS compliant ASL methodology will then be compared to the annual total depreciation expense under the ELG methodology. This procedure will be performed for each significant asset category and will provide the PUB with a realistic comparison of the differences in depreciation expense between the two IFRS compliant methodologies.

Manitoba Hydro has engaged Gannett Fleming to perform this work. The cost to engage Gannett Fleming for this purpose is expected to be $225,000 including disbursements.

Should you have any questions, please contact the writer at (204) 360-3257 or Greg Barnlund at (204) 360-5243.

Yours truly,

MANITOBA HYDRO LAW DIVISION
Per:

Brent Czarnecki
Barrister & Solicitor

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July 8, 2014

Mr. Brent Czarnecki
Law Department
Manitoba Hydro
22nd floor
360 Portage Avenue
Winnipeg MB R3C 0G8

Dear Mr. Czarnecki:

RE: Directive 8 & 9 of Order 43/13
Average Service Life (ASL) and Equal Life Group (ELG) Methods of Depreciation

In Order 43/13, dated April 26, 2013, the Board did not approve Manitoba Hydro's (MH's) proposed change to the ELG method of depreciation for rate setting purposes. In that Order the Board expressed concern that not enough information had been provided to assess the financial consequences on ratepayers, of a change to the ELG method. To address that deficiency, the Board issued Directives 8 & 9 of Order 43/13:

8. *That Manitoba Hydro file updated depreciation rates and schedules based on an International Financial Reporting Standards-compliant Average Service Life methodology with the next General Rate Application.*

9. *That Manitoba Hydro file with the Board, with the next General Rate Application, a chart showing a comparison of the impact on its Integrated Financial Forecast (i.e. 'Budget') of asset depreciation pursuant to the Average Service Life methodology(without net salvage) and the Equal Life Group methodology (without net salvage), applying both methodologies to all planned major capital additions.*

From Manitoba Hydro's May 6, 2014 letter, (a copy of which is attached) the Board understands that Manitoba Hydro has proposed meeting the above directives by developing new asset component groups for each significant asset category consistent with an IFRS compliant ASL Methodology. This expanded list of asset component groups will then be applied to a representative sample of physical facilities.

...2

The results of the asset re-componentization from the selected sample will then be extrapolated to the entire asset category. Rather than replicating a full depreciation study, this approach will identify additional asset components for each asset category. Manitoba Hydro will produce a set of IFRS compliant ASL depreciation rates that will be used to provide a comparison to the ELG depreciation expense.

The Board has not approved Manitoba Hydro's change to the use of the ELG methodology for rate-setting purposes. The depreciation methodology is expected to be addressed in Manitoba Hydro's next General Rate Application (GRA), to be filed later this year or early in 2015. To that end, the Board expects that to meet Directives 8 and 9 of Order 43 /13, Manitoba Hydro will file its GRA with fully IFRS compliant ASL based depreciation rates and schedules (that can be compared to fully IFRS compliant ESL based depreciation rates and schedules). The Board will expect Manitoba Hydro to file sufficient evidence to support the implementation of IFRS compliant ASL based depreciation rates (if so Ordered by the Board) for rate-setting purposes.

The Board will also expect Manitoba Hydro to provide a concise comparative analysis of the impact of Major new Generation and Transmission investments (including Wuskwatim G.S.; Bipole III; Keeyask G.S. and 750 Interconnection and GNTL) on future depreciation expense utilizing both the ELG methodology (without net salvage) and the ASL methodology (without net salvage) based on fully IFRS compliant ASL methodology rates.

The specifics of the engagement of external consultants by Manitoba Hydro, if required, are to be determined by Manitoba Hydro so as to be in a position to provide the Board with the required evidence as indicated above.

Sincerely,

"Original Signed By"

Kurt Simonsen, P. Eng.
Associate Secretary

KS/nac

c.c. Mr. Bob Peters, Board Counsel
Mr. Roger Cathcart, Board Advisor
Mr. Greg Barnlund, Manitoba Hydro
Interveners of Record, 2013/14 GRA and NFAT Review

Manitoba Hydro

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October 22, 2014

THE PUBLIC UTILITIES BOARD OF MANITOBA
400-330 Portage Avenue
Winnipeg, Manitoba
R3C 0C4

ATTENTION: Mr. H. Singh, Board Secretary and Executive Director

Dear Mr. Singh:

RE: Directives 8 and 9 of Order 43/13 re: Average Service Life and Equal Life Group Methods of Depreciation

On May 6, 2014, Manitoba Hydro filed a letter with the Public Utilities Board of Manitoba ("PUB") providing an update in response to Directives 8 and 9 of Order 43/13. These directives required Manitoba Hydro to file updated depreciation rates based on an International Financial Reporting Standards ("IFRS") compliant Average Service Life ("ASL") methodology, and to file a comparison of the impact on the Corporation's Integrated Financial Forecast of using the ASL methodology versus the Equal Life Group ("ELG") method of depreciation. In its letter, Manitoba Hydro indicated that it has developed a representative sampling approach that would provide a comparison of the two IFRS compliant depreciation methodologies in time for Manitoba Hydro's next General Rate Application ("GRA").

By letter of July 8, 2014, the PUB indicated that to meet Directives 8 and 9 of Order 43/13, it expects Manitoba Hydro to file its next GRA with fully IFRS compliant ASL depreciation rates and schedules that can be compared to fully IFRS compliant ELG depreciation rates and schedules.

As the PUB is aware, upon conversion to IFRS, Manitoba Hydro is moving from the ASL method of depreciation to the ELG method for financial reporting purposes. Manitoba Hydro understands that the PUB has not yet accepted the use of the ELG methodology for rate-setting purposes, and that the PUB is seeking additional information in order to assess the impact of the change in methodology on ratepayers.

As noted in its May 6, 2014 letter, in developing IFRS compliant ELG rates, Manitoba Hydro required approximately two years to review the past 70 years of historical asset records to be in a position to quantify and vintage the existing asset costs that were allocated between new and existing asset components. An IFRS compliant ASL method would require the development of additional asset component groups, which would entail a similar effort in time (i.e. two years) and resources to complete. As such, Manitoba Hydro will not be in a position to complete a full depreciation study based on an IFRS compliant ASL methodology in time for the next GRA.

In order to provide the PUB with information to assess the financial impact of the change in depreciation methodology in time for the next GRA, Manitoba Hydro has proposed a representative sampling approach. This approach would identify additional asset components for each significant asset category as would be required for an IFRS compliant ASL methodology; recognizing that the existing Canadian Generally Accepted Accounting Principles ("CGAAP") asset component groupings are not sufficient for an IFRS compliant ASL methodology. For the sample selected, Manitoba Hydro will develop IFRS compliant ASL depreciation rates. The resultant impacts from using these depreciation rates would then be extrapolated to produce a comparison of the annual depreciation expense between the IFRS compliant ASL and ELG methodologies. Manitoba Hydro believes that this analysis would support the move to the ELG methodology for rate setting purposes.

In the event that the PUB determines that the ELG method should not be used for rate-setting purposes, Manitoba Hydro could continue to use the existing CGAAP ASL depreciation rates for setting customer rates. However, in consideration of Manitoba Hydro's existing asset component structure, Manitoba Hydro is adopting the ELG method for IFRS compliant financial reporting purposes (as opposed to rate setting purposes). In this circumstance, Manitoba Hydro would be required, for financial reporting purposes, to establish a rate-regulated account to capture the difference between depreciation expense recorded for rate-setting purposes (existing CGAAP ASL methodology) and depreciation expense that will be recorded for financial reporting purposes (ELG methodology). The approach to capture the differences in a rate-regulated account is an interim measure for rate-setting purposes and would subsequently have to be re-examined at a future GRA.

In an effort to further the mutual understanding between Manitoba Hydro and the PUB on these technical financial issues, Manitoba Hydro is prepared to meet with the PUB's technical financial/accounting advisor. Should you have any questions, please contact the writer at (204) 360-3257 or Greg Barnlund at (204) 360-5243.

Yours truly,

MANITOBA HYDRO LAW DIVISION
Per:

Brent Czarnecki
Barrister & Solicitor

cc. Mr. R. Cathcart, Cathcart Advisors Inc.

GANNETT FLEMING RESPONSE TO PROVIDE COMPLIANCE WITH MANITOBA PUBLIC UTILITIES BOARD DECISION 43/13

Prepared by:

Gannett Fleming

Excellence Delivered ***As Promised***

MANITOBA HYDRO

Winnipeg, Manitoba

GANNETT FLEMING RESPONSE TO

PROVIDE COMPLIANCE WITH

MANITOBA PUBLIC UTILITIES BOARD

DECISION 43/13

GANNETT FLEMING CANADA ULC

Calgary, Alberta

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MANITOBA HYDRO

GANNETT FLEMING RESPONSE TO PROVIDE COMPLIANCE WITH MANITOBA PUBLIC UTITLTIES BOARD DECISION 43/13

EXECUTIVE SUMMARY

Gannett Fleming Canada ULC ("Gannett Fleming") was retained by Manitoba Hydro for assistance in responding to directives #8 and #9 from Public Utilities Board Order 43/13 for Manitoba Hydro's 2014/15 and 2015/16 General Rate Application (GRA). The directives requested information with respect to an analysis of the level of asset componentization that would be required to develop IFRS – compliant depreciation rates using the ASL procedure and an analysis comparing the depreciation expense resulting from the conversion to the ELG procedure as compared to the depreciation expense resulting from the use of an IFRS compliant ASL procedure.

In order to strictly comply with Directive #8, a detailed analysis of virtually all of the current Manitoba Hydro accounts would be required which, given the extreme volume of account information, could not be completed in time for the current GRA. In order to reasonably respond to the directives in the time period allotted, Gannett Fleming worked with Manitoba Hydro to develop a representative sample of additional asset component groups for further analysis. Representative sample components and comparisons between ELG and IFRS compliant ASL depreciation calculations were developed for both the March 31, 2014 account balances and the forecasted Bipole III and Keeyask projects. The sample accounts chosen represent approximately 20% of the total March 31, 2014 asset balance and 20% of the 10 year forecast project balances and are thus, sufficiently representative of the investment base being analyzed.

The analysis completed by Gannett Fleming on the March 31, 2014 balances, resulted in a $738,000 difference between the depreciation calculated using the ELG method and the depreciation calculated using the ASL method. Extrapolated across the full March 31, 2014 asset balance, the ELG method is $3.5 million higher on an annual basis than the ASL method applied to more components. The analysis completed on the forecasted Bipole III and Keeyask projects resulted in a $140,000 difference between the ELG and IFRS-compliant ASL methods where the ELG procedure was lower than the IFRS compliant ASL procedure. Extrapolated across the forecasted asset balances, the ELG method is $0.7 million lower of the analyzed projects than the ASL method.

Based on the results of the testing presented in this report, Gannett Fleming views that the statements made by Manitoba Hydro in its previous GRA proceeding regarding the fact that an IFRS compliant ASL procedure would result in a similar level of depreciation expense as the proposed change to the ELG procedure have been demonstrated.

PART I. INTRODUCTION

MANITOBA HYDRO
GANNETT FLEMING RESPONSE TO PROVIDE
COMPLIANCE WITH MANITOBA PUBLIC UTITLTIES BOARD
DECISION 43/13

PART 1. BACKGROUND AND SCOPE

BACKGROUND

In its 2012/13 and 2013/14 General Rate Application ("GRA"), Manitoba Hydro informed the PUB that it would be changing from the Average Service Life ("ASL") procedure to the Equal Life Group ("ELG") procedure in the calculation of the depreciation rates upon its transition to IFRS in order to facilitate compliance with the requirements of IFRS. Mr. Larry Kennedy of Gannett Fleming Canada ULC ("Gannett Fleming") provided expert testimony relating to the enhanced ability of the ELG procedure to comply with the requirements of the IFRS without the need for additional componentization, as would be required to continue with the ASL procedure under IFRS. One of the key concerns identified during the hearing was the increase in depreciation expense resulting from the change to the ELG method in the years following the transition to IFRS. It was the stated view of Mr. Kennedy that the additional componentization that would be required in order to apply the ASL method under IFRS would result in a similar increase in depreciation expense. The advantage to changing to the ELG method is that very little additional componentization is required which significantly reduces existing and ongoing efforts and costs by Manitoba Hydro to comply with IFRS.

Based on their findings in Manitoba Hydro's GRA, the PUB issued the following directives to Manitoba Hydro as a means to better understand the differences between the ASL and ELG methodologies:

> ***8.*** *That Manitoba Hydro file updated depreciation rates and schedules based on an International Financial Reporting Standards-compliant Average Service Life methodology with the next General Rate Application.*

9. *That Manitoba Hydro file with the Board, with the next General Rate Application, a chart showing a comparison of the impact on its Integrated Financial Forecast (i.e. 'Budget') of asset depreciation pursuant to the Average Service Life methodology (without net salvage) and the Equal Life Group methodology (without net salvage), applying both methodologies to all planned major capital additions.*

SCOPE OF STUDY

Gannett Fleming was retained by Manitoba Hydro to provide an analysis of the level of asset componentization that would be required to develop IFRS – compliant depreciation rates using the ASL Procedure and to model a comparison of the depreciation expense resulting from the conversion to the ELG procedure as compared to the depreciation expense resulting from the use of an IFRS compliant ASL procedure. This report presents a discussion of the analysis undertaken by Gannett Fleming and provides the comparative results from the analysis.

Strict compliance with Directive 8 from the Public Utilities Board Order 43/13 would require a detailed analysis of virtually all of the current Manitoba Hydro accounts. Such an analysis would require the detailed manual review of over 70 years of detailed project capitalization records, many years of detailed retirement transactions, and a detailed review of the current investment in all accounts. These reviews are required in order to determine the amount of investment by installation year for accounts that could be componentized further, and to appropriately develop a retirement rate analysis for the support of an average life estimate for each of the new components. Additionally, the accumulated depreciation accounts would require the same level of componentization as the related asset accounts.

In order to reasonably respond to PUB Order 43/13, directives #8 and #9 in time for Manitoba Hydro's 2014/15 and 2015/16 GRA, Gannett Fleming worked with Manitoba Hydro to develop a representative sample of additional asset component groups for further review and analysis.

This report outlines the manner in which a representative sample of accounts were selected for analysis and review; presents an overview of the manner in which each of the components where assigned an average service life estimate for use in this analysis; describes the manner in which the review was undertaken; and will provide a summary of the analysis and the conclusions of Gannett Fleming resulting from the study.

PART II. ANALYSIS AND REVIEW

PART 2. ANALYSIS AND REVIEW

SELECTION OF THE MARCH 31, 2014 COMPONENTS TO REVIEW

Gannett Fleming is a large internationally acclaimed professional engineering firm that has been active in the design, construction and inspection of Dams, Levees and Hydroelectric infrastructure since 1915. Gannett Fleming is a member of the Canadian Dam Association ("CDA") and frequently presents on a number of issues to the membership of the CDA. In addition to reliance on the Manitoba Hydro engineering and operations staff, senior leadership staff of the Gannett Fleming Dam and Earth Sciences group were consulted during various phases of this project to ensure that the Gannett Fleming recommendations regarding componentization reasonably reflect current and historic engineering practices related to dams and levees.

Based on the broad experience of Gannett Fleming developing depreciation practices and policies ensuring compliance with the IFRS for utilities across Canada, Gannett Fleming does not view that the current level of Manitoba Hydro asset componentization is sufficient if using the ASL method for financial statements prepared under IFRS. In the experience of Gannett Fleming, electric generation utilities across Canada that use the ASL procedure have a significantly increased level of componentization for financial reporting purposes[1].

Gannett Fleming views that Manitoba Hydro's current level of depreciable components would need to be broken down into additional components based on asset dollar value, differing service lives and differing forces of retirement in order for Manitoba Hydro to continue using the ASL procedure in the development of depreciation rates under the IFRS.

Gannett Fleming worked with Manitoba Hydro to develop a representative sample of additional asset component groups for further review and analysis based on the following:

- Where it is easily apparent that the current group will not meet the componentization requirements of the IFRS;

[1] Including BC Hydro, Newfoundland and Labrador Hydro and SaskEnergy.

- Where a reasonable estimate of the average service life can be determined by operational staff. In this manner, a reasonable estimate of the service life estimate for the new accounts could be made without the detailed review of all historic retirement information;
- Where the current groups selected will provide a statistically significant sample size such that the results can be considered to be representative of a full review of accounts.
- Where the resultant groups selected represent a reasonable cross sample of accounts and facilities.

Based on the above criteria, the following accounts were selected for analysis:

- Turbines and Generators – Generation
- A/C Electrical Power Systems – Generation
- Poles and Fixtures – Transmission
- Other Transformers – Transmission
- Interrupting Equipment – Substations
- Poles and Fixtures – Distribution
- Buildings – 360 Portage – Electro/mechanical

The data used in the 2014 depreciation study as filed in this application was used for the analysis and componentization. As of March 31, 2014 the above account groups represented $2.9 billion of Manitoba Hydro's total March 31, 2014 cost base of $14.2 billion (or 20%). In the view of Gannett Fleming, a sample size representing 20% of the total investment comprising a broad cross section of asset groups is representative of the investment as a whole.

In order to compare the impacts of the ELG procedure to an IFRS compliant ASL procedure on a large level of new investment as identified in Manitoba Hydro's Capital Expenditure Forecast (CEF-14), current component groups relating to the future investment for the Bipole III and Keeyask Generating Station projects were tested. These two projects represent 55% of the total electric operations capital forecast over the next 10 years and the sample accounts selected represent approximately 20% of the project's balance. Specifically, the following component groups related to the new investment of the above two projects were identified for specific review:

- Synchronous Condensers and Unit Transformers – Bipole III
- Converter Equipment – Bipole III
- Water control Systems – Keeyask
- Turbines and Generators – Keeyask
- A/C electrical Power Systems – Keeyask

Figure 1, on the following page identifies the current components and the further componentized new groupings used for the purposes of comparative testing. Gannett Fleming notes that this level of componentization and new component development is reasonable for the purposes of testing in order to comply with the PUB directives. However, the continued use of an IFRS compliant ASL procedure would require a significant amount of additional review of the tested components, in addition to a complete review of all components not included in the sample.

Figure 1 – Summary of the Representative Sample of Existing and Additional Components Used in the Gannett Fleming Testing

March 31, 2014 Accounts:

Existing Asset Component	Existing Asset Component
- Turbines and Generators (Generation)	- Turbines - Generators
- A/C Electrical Power Systems (Generation)	- Step-up transformers manufactured before 1950 - Step-up transformers manufactured in 1950 or later - A/C Electrical Power Systems – other equipment
- Poles and Fixtures (Transmission)	- Wood Poles and Fixtures - Cross-arms
- Other Transformers (Substations)	- Other Transformers - Potential and Current Transformers
- Interrupting Equipment (Substations)	- Other Interrupting Equipment - Vacuum Circuit Breakers - Min Oil and SF6 Breakers - Air Magnetic Breakers - Air Blast and Oil Bulk Breakers
Existing Asset Component	**Existing Asset Component**
- Poles and Fixtures (Distribution)	- Wood Poles and Fixtures - Cross-arms
- Buildings (360 Portage) – Electro/mechanical	- Finishes - Mechanical/Windows and Other - Millwork and Elevators - Interior Glaze/Drywall and Electrical

Capital Expenditure Forecast (CEF-14):

Existing Asset Component	Test Sample Asset Component
- Synchronous Condensers and Unit Transformers (Bipole III)	- Synchronous Condensers - Unit Transformers
- Converter Equipment (Bipole III)	- HVDC Converter Valves and Valve Cooling Equipment - HVDC Converter Transformers
- Water Control Systems (Keeyask)	- Water Control Systems - Ice, Debris and Public Safety Booms
- Turbines and Generators (Keeyask)	- Turbines - Generators
- A/C Electrical Power Systems (Keeyask)	- Step-up transformers manufactured in 1950 or later - A/C Electrical Power Systems – other equipment

DEVELOPMENT OF AVERAGE SERVICE LIFE ESTIMATES FOR THE NEW COMPONENT GROUPS

In order to test the impacts of the ELG Procedure to an IFRS compliant ASL procedure, an average service life estimate is required for the additional level of componentization used in the development of the ASL depreciation expense. The average service life estimates as used in the depreciation study filed with Manitoba Hydro's current application were used as the basis for the development of the new more componentized average service life estimates. The comparisons to the ELG procedure used average service lives as used in the current 2014 depreciation study.

Gannett Fleming notes that in the development of the additional components, the componentization used for ELG purposes in the 2014 depreciation study was used as a starting point. Each of the new ASL components were then analyzed to determine if the new component would have a longer or shorter life than the ELG component. In some circumstances, one of the new components represented such a large percentage of investment in the existing account that the larger component has been assigned the same life estimate as the larger ELG component.

The development of the average service life estimates for the IFRS compliant ASL procedure included the following review for each new account:

- Review by Manitoba Hydro Operations staff to provide an indication of the average service life of each of the components;
- Review of the Manitoba Hydro internal estimates by Gannett Fleming;
- Review to determine if the lives for the new components are consistent with the lives as determined for the ELG components in the current depreciation study; and
- The lives of all components were rounded to the nearest 5 years.

The resultant average service life estimates for all new components are identified on the Table of results in Part 3 of this report.

TESTING AND REVIEW

The Gannett Fleming testing was completed in two parts. Firstly, for the investment as of March 31, 2014, Gannett Fleming completed a series of ASL procedure calculations on the increased level of componentization which included the new average service life estimates for each of the components. The ELG calculations were developed in the current depreciation study filed with this application. Secondly, a first year calculation was made for the investment related to the two new capital projects, which required development of detailed depreciation calculations for the ELG and IFRS compliant ASL procedures.

A component of the depreciation rates includes the true-up of accumulated depreciation variances between the level of actual accumulated depreciation balances and the calculated (or theoretical) accumulated depreciation balances. In order to develop the true-up calculations, Gannett Fleming developed an allocation of the accumulated depreciation amounts as of March 31, 2014 for use with the IFRS compliant ASL procedure. For the ELG components, the true up calculations were developed in the current depreciation study.

A table summarizing the results of the analysis is provided in Part 3 of this report.

PART III. RESULTS AND CONCLUSIONS

PART 3. RESULTS AND CONCLUSIONS

RESULTS

Based on the analysis completed by Gannett Fleming on the March 31, 2014 balances, the depreciation expense related to the proposed use of the ELG procedure on the $2.9 billion of original cost is $738,000 higher as compared to the use of the IFRS compliant ASL procedure. Extrapolating the $0.7 million difference to 100% of the March 31, 2014 asset balance equates to an approximately $3.5 million annual difference between the two approaches. However, on the analysis of the forecast Bipole III and Keeyask projects the depreciation expense related to the proposed ELG procedure is $140,000 less than the IFRS compliant ASL procedure. Extrapolating the ($0.1) million difference between the IFRS-compliant ASL method and the ELG method results over the total of the analyzed project additions over the next 10 years, equates to an approximately ($0.7) million annual difference between the two approaches. The results of the Gannett Fleming Analysis is summarized in Table 1 on page III-5 and in more detail by account in Tables 2, 3 and 4 provided at pages III-6, III-7 and III-8 of this report.

Figure 2 - Summary of Differences in Depreciation Procedures

Component	Depreciation Expense ($ millions) ELG Method	ASL Method	Difference
March 31, 2014 Accounts:			
A/C Electrical Power Systems (Generation)	7.16		
- Step-up Transformers Manufactured before 1950		-	
- Step-up Transformers Manufactured in 1950 or later		3.63	
- A/C Electrical Power Systems – Other Equipment		4.35	
Turbines and Generators (Generation)	23.45		
- Turbines		8.80	
- Generators		15.15	
Poles and Fixtures (Transmission)	2.11		
- Wood Poles and Fixtures		1.31	
- Cross-arms		0.42	
Other Transformers (Substations)	2.54		
- Other Transformers		1.61	
- Potential and Current Transformers		0.50	
Interrupting Equipment (Substations)	4.85		
- Other Interrupting Equipment		2.67	
- Vacuum Circuit Breakers		0.73	
- Min Oil and SF6 Breakers		1.09	
- Air Magnetic Breakers		0.44	
- Air Blast and Oil Bulk Breakers		0.09	
Poles and Fixtures (Distribution)	10.59		
- Wood Poles and Fixtures		7.62	
- Cross-arms		1.41	
Buildings (360 Portage)	1.98		
- Electro/mechanical - Finishes		0.73	
- Electro/mechanical – Mechanical/Windows and Other		1.05	
- Electro/mechanical – Millwork and Elevators		0.16	
- Electro/mechanical – Interior Glaze/Drywall and Electrical		0.17	
Sub-Total March 31, 2014 Balances	**52.67**	**51.93**	**0.74**
Capital Expenditure Forecast:			
Synchronous Condensers and Unit Transformers (Bipole III)*	3.66		
- Synchronous Transformers		1.93	
- Unit Transformers		1.68	
Converter Equipment (Bipole III)	14.97		
- HVDC Converter Valves and Valve Cooling Equipment		6.17	
- HVDC Converter Transformers		8.83	
Water Control Systems (Keeyask)**	9.04		
- Water Control Systems		8.15	
- Ice, Debris and Public Safety Booms		0.71	
Turbines and Generators (Keeyask)	9.79		
- Turbines		3.95	
- Generators		6.59	
A/C Electrical Power Systems (Keeyask)	4.77		
- Step-up Transformers Manufactured in 1950 or later		1.03	
- A/C Electrical Power Systems – Other Equipment		3.33	
Sub-Total Forecast Balances	**42.23**	**42.37**	**(0.14)**

** Assumes Fiscal 2019 when Bipole III is fully in service*
*** Assumes 2021 when Keeyask GS is fully in service*

CONCLUSION

The $738,000 difference based on the accounts tested as of March 31, 2014 between an IFRS-compliant ASL and ELG method demonstrates that compliance with the depreciation requirements of IFRS will result in a similar increase in depreciation expense, regardless of the depreciation method used. In Appendix 5.7 of this application, Manitoba Hydro indicates the estimated annual increase in depreciation expense for complying with IFRS by changing to the ELG method is $36 million. This annual increase in depreciation would be approximately $33 million if Manitoba Hydro were to continue with an IFRS compliant ASL method.

The difference of $140,000 resulting from analysis comparing the impact on the two large new capital projects (Bipole III and Keeyask) also demonstrates the convergence of the depreciation expense between the two methods.

Overall, the testing completed by Gannett Fleming indicates that a similar impact will result when the two methods are applied to a significant level of asset costs (both as of March 31, 2014, and on the two large forecasted capital projects). Gannett Fleming strongly cautions that depreciation expense is an estimate, and that this analysis is on a representative sample basis only and it is possible that the results of a complete study of existing and projected asset additions could be smaller or larger than the balances provided in this analysis. Such differences may also be altered by differences between actual and projected levels of capital expenditures and asset retirements.

Based on the results of the testing presented in this report, Gannett Fleming views that the statements made in the 2013/2014 General Rate Application Proceeding regarding the fact that an IFRS compliant ASL Procedure would result in a similar level of depreciation expense as the proposed change to the ELG procedure have been demonstrated. The over-riding benefit of the proposed ELG procedure is the elimination of the need to undertake a very significant effort to develop the level of componentization required for the use of an IFRS compliant ASL procedure.

MANITOBA HYDRO
TABLE 1. SUMMARY OF AVERAGE SERVICE LIFE VERSUS EQUAL LIFE GROUP
PLANT AS OF MARCH 31, 2014

ACCOUNT	ACCOUNT DESCRIPTION	FILED ELG: LIFE SPAN DATE	FILED ELG: SURVIVOR CURVE	FILED ELG: SURVIVING ORIGINAL COST AS OF MARCH 31, 2014	FILED ELG: CALCULATED ANNUAL ACCRUAL AMOUNT	FILED ELG: CALCULATED ANNUAL ACCRUAL RATE (%)	FILED ELG: ANNUAL PROVISION FOR TRUE-UP	FILED ELG: TOTAL DEPRECIATION RELATED TO LIFE EXPENSE	FILED ELG: TOTAL DEPRECIATION RELATED TO LIFE RATE (%)	ASL - COMPONENTIZATION: LIFE SPAN DATE	ASL - COMPONENTIZATION: SURVIVOR CURVE	ASL - COMPONENTIZATION: SURVIVING ORIGINAL COST AS OF MARCH 31, 2014	ASL - COMPONENTIZATION: CALCULATED ANNUAL ACCRUAL AMOUNT	ASL - COMPONENTIZATION: CALCULATED ANNUAL ACCRUAL RATE (%)	ASL - COMPONENTIZATION: ANNUAL PROVISION FOR TRUE-UP	ASL - COMPONENTIZATION: TOTAL DEPRECIATION RELATED TO LIFE EXPENSE	ASL - COMPONENTIZATION: TOTAL DEPRECIATION RELATED TO LIFE RATE (%)
	(1)		(2)	(3)	(4)	(5)=(4)/(3)	(6)	(7)=(4)+(6)	(8)=(7)/(3)		(9)	(10)	(11)	(12)=(11)/(10)	(13)	(14)=(11)+(13)	(15)=(14)/(10)
Great Falls 1105P A/C Electrical Power Systems:																	
1105P1	Step-Up Transformers Manufactured before 1950									2063	60-R4	163,626	2,733	1.67	(25,260)	(22,527)	(13.77)
1105P2	Step-up Transformers Manufactured in 1950 or later									2063	40-R4	3,811,668	95,292	2.50	(7,877)	87,415	2.29
1105P3	A/C Electrical Power Systems - Other Equipment									2063	55-R4	5,517,794	100,696	1.82	(9,812)	90,884	1.65
1105P	**A/C Electrical Power Systems - Total for Parent Account**	2063	55-R4	**9,493,088**	**178,427**	**1.88**	**(20,168)**	**158,259**	**1.67**			**9,493,088**	**198,721**	**2.09**	**(42,949)**	**155,772**	**1.64**
Point du Bois 1110P A/C Electrical Power Systems:																	
1110P1	Step-Up Transformers Manufactured before 1950																
1110P2	Step-up Transformers Manufactured in 1950 or later									2040	40-R4	6,324,690	211,361	3.34	(42,537)	168,824	2.67
1110P3	A/C Electrical Power Systems - Other Equipment									2040	55-R4	1,435,296	49,693	3.46	(6,326)	43,367	3.02
1110P	**A/C Electrical Power Systems - Total for Parent Account**	2040	55-R4	**7,759,986**	**264,381**	**3.41**	**(48,663)**	**215,718**	**2.78**			**7,759,986**	**261,054**	**3.36**	**(48,863)**	**212,191**	**2.73**
Seven Sisters 1115P A/C Electrical Power Systems:																	
1115P1	Step-Up Transformers Manufactured before 1950									2072	60-R4	348,199	5,815	1.67	(11,285)	(5,470)	(1.57)
1115P2	Step-up Transformers Manufactured in 1950 or later									2072	40-R4	4,455,082	111,377	2.50	(18,944)	92,433	2.07
1115P3	A/C Electrical Power Systems - Other Equipment									2072	50-R4	7,120,950	135,967	1.91	(14,934)	121,033	1.70
1115P	**A/C Electrical Power Systems - Total for Parent Account**	2072	55-R4	**11,924,230**	**223,527**	**1.87**	**(37,834)**	**185,693**	**1.56**			**11,924,231**	**253,159**	**2.12**	**(45,163)**	**207,996**	**1.74**
Slave Falls 1120P A/C Electrical Power Systems:																	
1120P1	Step-Up Transformers Manufactured before 1950									2072	60-R4	960,483	16,328	1.70	(827)	15,501	1.61
1120P2	Step-up Transformers Manufactured in 1950 or later																
1120P3	A/C Electrical Power Systems - Other Equipment									2072	55-R4	20,671,367	382,740	1.85	(13,147)	369,593	1.79
1120P	**A/C Electrical Power Systems - Total for Parent Account**	2072	55-R4	**21,631,850**	**421,951**	**1.95**	**(9,787)**	**412,164**	**1.91**			**21,631,850**	**399,068**	**1.84**	**(13,974)**	**385,094**	**1.78**
Pine Falls 1125P A/C Electrical Power Systems:																	
1125P1	Step-Up Transformers Manufactured before 1950									2092	60-R4	350,135	5,847	1.67	(11,236)	(5,389)	(1.54)
1125P2	Step-up Transformers Manufactured in 1950 or later																
1125P3	A/C Electrical Power Systems - Other Equipment									2092	55-R4	4,746,843	86,393	1.82	(11,299)	75,094	1.58
1125P	**A/C Electrical Power Systems - Total for Parent Account**	2092	55-R4	**5,096,978**	**92,115**	**1.81**	**(11,342)**	**80,773**	**1.58**			**5,096,978**	**92,240**	**1.81**	**(22,535)**	**69,705**	**1.37**
McArthur Falls 1130P A/C Electrical Power Systems:																	
1130P1	Step-Up Transformers Manufactured before 1950									2095	60-R4	319,824	5,341	1.67	(8,255)	(2,914)	(0.91)
1130P2	Step-up Transformers Manufactured in 1950 or later																
1130P3	A/C Electrical Power Systems - Other Equipment									2095	55-R4	2,201,937	40,075	1.82	(9,572)	30,503	1.39
1130P	**A/C Electrical Power Systems - Total for Parent Account**	2095	55-R4	**2,521,761**	**43,075**	**1.71**	**(9,746)**	**33,329**	**1.32**			**2,521,761**	**45,416**	**1.80**	**(17,827)**	**27,589**	**1.09**
Kelsey 1135P A/C Electrical Power Systems:																	
1135P1	Step-Up Transformers Manufactured before 1950																
1135P2	Step-up Transformers Manufactured in 1950 or later									2101	40-R4	15,764,992	394,125	2.50	22,946	417,071	2.65
1135P3	A/C Electrical Power Systems - Other Equipment									2101	55-R4	24,729,522	450,077	1.82	30,199	480,276	1.94
1135P	**A/C Electrical Power Systems - Total for Parent Account**	2101	55-R4	**40,494,515**	**779,913**	**1.93**	**42,291**	**822,204**	**2.03**			**40,494,514**	**844,202**	**2.08**	**53,145**	**897,347**	**2.22**
Grand Rapids 1140P A/C Electrical Power Systems:																	
1140P1	Step-Up Transformers Manufactured before 1950																
1140P2	Step-up Transformers Manufactured in 1950 or later									2091	40-R4	2,957,039	73,926	2.50	(4,628)	69,298	2.34
1140P3	A/C Electrical Power Systems - Other Equipment									2091	55-R4	5,283,506	96,160	1.82	(15,370)	80,790	1.53
1140P	**A/C Electrical Power Systems - Total for Parent Account**	2091	55-R4	**8,240,545**	**153,036**	**1.86**	**(16,600)**	**136,436**	**1.66**			**8,240,545**	**170,086**	**2.06**	**(19,998)**	**150,088**	**1.82**
Kettle 1145P A/C Electrical Power Systems:																	
1145P1	Step-Up Transformers Manufactured before 1950																
1145P2	Step-up Transformers Manufactured in 1950 or later									2111	40-R4	36,244,611	906,115	2.50	24,903	931,018	2.57
1145P3	A/C Electrical Power Systems - Other Equipment									2111	50-R4	2,535,002	50,700	2.00	22,041	72,741	2.87
1145P	**A/C Electrical Power Systems - Total for Parent Account**	2111	55-R4	**38,779,613**	**745,736**	**1.92**	**12,798**	**758,534**	**1.96**			**38,779,613**	**956,815**	**2.47**	**46,944**	**1,003,759**	**2.59**
Laurie River 1150P A/C Electrical Power Systems:																	
1150P1	Step-Up Transformers Manufactured before 1950																
1150P2	Step-up Transformers Manufactured in 1950 or later																
1150P3	A/C Electrical Power Systems - Other Equipment									2035	55-R4	1,441,945	39,580	2.74	3,966	43,546	3.02
1150P	**A/C Electrical Power Systems - Total for Parent Account**	2035	55-R4	**1,441,945**	**40,426**	**2.80**	**4,948**	**45,374**	**3.15**			**1,441,945**	**39,580**	**2.74**	**3,966**	**43,546**	**3.02**
Jenpeg 1155P A/C Electrical Power Systems:																	
1155P1	Step-Up Transformers Manufactured before 1950																
1155P2	Step-up Transformers Manufactured in 1950 or later									2118	40-R4	5,710,258	142,756	2.50	(56,656)	86,100	1.51
1155P3	A/C Electrical Power Systems - Other Equipment									2118	55-R4	15,931,351	289,951	1.82	(30,158)	259,793	1.63
1155P	**A/C Electrical Power Systems - Total for Parent Account**	2118	55-R4	**21,641,608**	**394,933**	**1.82**	**(63,837)**	**331,096**	**1.53**			**21,641,609**	**432,707**	**2.00**	**(86,814)**	**345,893**	**1.60**
Churchill River Diversion 1165P A/C Electrical Power Systems:																	
1165P1	Step-Up Transformers Manufactured before 1950																
1165P2	Step-up Transformers Manufactured in 1950 or later																
1165P3	A/C Electrical Power Systems - Other Equipment										55-R4	1,710,889	31,138	1.82	(6,356)	24,782	1.45
1165P	**A/C Electrical Power Systems - Total for Parent Account**		55-R4	**1,710,889**	**31,121**	**1.82**	**(4,201)**	**26,920**	**1.57**			**1,710,889**	**31,138**	**1.82**	**(6,356)**	**24,782**	**1.45**
Long Spruce 1170P A/C Electrical Power Systems:																	
1170P1	Step-Up Transformers Manufactured before 1950																
1170P2	Step-up Transformers Manufactured in 1950 or later									2118	40-R4	19,424,177	485,604	2.50	9,325	494,929	2.55
1170P3	A/C Electrical Power Systems - Other Equipment									2118	55-R4	11,186,563	203,595	1.82	1,202	204,797	1.83
1170P	**A/C Electrical Power Systems - Total for Parent Account**	2118	55-R4	**30,610,740**	**560,009**	**1.83**	**(99,219)**	**460,790**	**1.51**			**30,610,740**	**689,199**	**2.25**	**10,527**	**699,726**	**2.29**

MANITOBA HYDRO
TABLE 1. SUMMARY OF AVERAGE SERVICE LIFE VERSUS EQUAL LIFE GROUP
PLANT AS OF MARCH 31, 2014

		FILED ELG								ASL - COMPONENTIZATION							
ACCOUNT	ACCOUNT DESCRIPTION	LIFE SPAN DATE	SURVIVOR CURVE	SURVIVING ORIGINAL COST AS OF MARCH 31, 2014	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE (%)	ANNUAL PROVISION FOR TRUE-UP	TOTAL DEPRECIATION RELATED TO LIFE EXPENSE	TOTAL DEPRECIATION RELATED TO LIFE RATE (%)	LIFE SPAN DATE	SURVIVOR CURVE	SURVIVING ORIGINAL COST AS OF MARCH 31, 2014	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE (%)	ANNUAL PROVISION FOR TRUE-UP	TOTAL DEPRECIATION RELATED TO LIFE EXPENSE	TOTAL DEPRECIATION RELATED TO LIFE RATE (%)
	(1)		(2)	(3)	(4)	(5)=(4)/(3)	(6)	(7)=(4)+(6)	(8)=(7)/(3)		(9)	(10)	(11)	(12)=(11)/(10)	(13)	(14)=(11)+(13)	(15)=(14)/(10)
Limestone 1175P A/C Electrical Power Systems:																	
1175P1	Step-Up Transformers Manufactured before 1950																
1175P2	Step-up Transformers Manufactured in 1950 or later									2131	40-R4	43,746,177	1,093,654	2.50	(99,436)	994,218	2.27
1175P3	A/C Electrical Power Systems - Other Equipment									2131	55-R4	100,842,764	1,835,338	1.82	(94,006)	1,741,332	1.73
1175P	**A/C Electrical Power Systems - Total for Parent Account**	2131	55-R4	**144,588,941**	**2,741,516**	**1.90**	**(233,699)**	**2,507,817**	**1.73**			**144,588,941**	**2,928,992**	**2.03**	**(193,442)**	**2,735,550**	**1.89**
Wuskwatim 1180P A/C Electrical Power Systems:																	
1180P1	Step-Up Transformers Manufactured before 1950																
1180P2	Step-up Transformers Manufactured in 1950 or later									2152	40-R4	403,600	10,090	2.50	(71)	10,019	2.48
1180P3	A/C Electrical Power Systems - Other Equipment									2152	55-R4	1,288,063	23,443	1.82	(118)	23,325	1.81
1180P	**A/C Electrical Power Systems - Total for Parent Account**	2152	55-R4	**1,691,663**	**32,649**	**1.93**	**(192)**	**32,457**	**1.92**			**1,691,663**	**33,533**	**1.98**	**(189)**	**33,344**	**1.97**
Wuskwatim Power Limited Partnership ("WPLP") 1181P A/C Electrical Power Systems:																	
1181P1	WPLP - Step-Up Transformers Manufactured before 1950																
1181P2	WPLP - Step-up Transformers Manufactured in 1950 or later									2152	40-R4	11,907,305	297,683	2.50	(2,902)	294,781	2.48
1181P3	WPLP - A/C Electrical Power Systems - Other Equipment									2152	55-R4	38,001,362	691,625	1.82	(4,846)	686,779	1.81
1181P	**A/C Electrical Power Systems - Total for Parent Account**	2152	55-R4	**49,908,667**	**963,237**	**1.93**	**(7,597)**	**955,640**	**1.91**			**49,908,667**	**989,308**	**1.98**	**(7,748)**	**981,560**	**1.97**
1105G1	Turbines									2063	75-S3	14,949,264	250,605	1.68	16,610	267,215	1.79
1105G2	Generators									2063	45-S3	18,869,048	419,849	2.23	27,659	447,508	2.37
1105G	**Turbines and Generators - Total for Parent Account**	2063	60-S3	**33,818,312**	**647,992**	**1.92**	**39,027**	**687,019**	**2.03**			**33,818,312**	**670,454**	**1.98**	**44,269**	**714,723**	**2.11**
Pointe du Bois 1110G:																	
1110G1	Turbines									2040	75-S3	27,977,470	884,721	3.16	(223,804)	660,917	2.36
1110G2	Generators									2040	45-S3	3,921,590	127,123	3.24	(31,420)	95,703	2.44
1110G	**Turbines and Generators - Total for Parent Account**	2040	60-S3	**31,899,060**	**1,036,836**	**3.25**	**(256,998)**	**779,838**	**2.44**			**31,899,060**	**1,011,844**	**3.17**	**(255,224)**	**756,620**	**2.37**
Seven Sisters 1115G:																	
1115G1	Turbines									2072	75-S3	34,324,616	538,754	1.57	(29,435)	509,319	1.48
1115G2	Generators									2072	45-S3	20,124,707	448,104	2.23	(51,168)	396,936	1.97
1115G	**Turbines and Generators - Total for Parent Account**	2072	60-S3	**54,449,323**	**986,438**	**1.81**	**(64,103)**	**922,335**	**1.69**			**54,449,323**	**986,858**	**1.81**	**(80,603)**	**906,255**	**1.66**
Slave Falls 1120G:																	
1120G1	Turbines									2072	75-S3	5,916,360	92,011	1.56	(488)	91,523	1.55
1120G2	Generators									2072	45-S3	6,330,169	140,617	2.22	(1,131)	139,486	2.20
1120G	**Turbines and Generators - Total for Parent Account**	2072	60-S3	**12,246,529**	**224,685**	**1.83**	**(3,206)**	**221,479**	**1.81**			**12,246,529**	**232,628**	**1.90**	**(1,619)**	**231,009**	**1.89**
Pine Falls 1125G:																	
1125G1	Turbines									2092	75-S3	4,890,684	65,401	1.34	(9,048)	56,353	1.15
1125G2	Generators									2092	45-S3	4,427,470	98,290	2.22	(27,038)	71,252	1.61
1125G	**Turbines and Generators - Total for Parent Account**	2092	60-S3	**9,318,154**	**150,312**	**1.61**	**(22,361)**	**127,951**	**1.37**			**9,318,154**	**163,691**	**1.76**	**(36,086)**	**127,605**	**1.37**
McArthur Falls 1130G:																	
1130G1	Turbines									2095	75-S3	2,902,707	38,684	1.33	(16,087)	22,597	0.78
1130G2	Generators									2095	45-S3	2,476,911	54,987	2.22	(59,614)	(4,627)	(0.19)
1130G	**Turbines and Generators - Total for Parent Account**	2095	60-S3	**5,379,618**	**77,690**	**1.44**	**(27,218)**	**50,472**	**0.94**			**5,379,618**	**93,671**	**1.74**	**(75,701)**	**17,970**	**0.33**
Kelsey 1135G:																	
1135G1	Turbines									2101	75-S3	78,758,820	1,077,668	1.37	26,857	1,104,525	1.40
1135G2	Generators									2101	45-S3	67,625,037	1,501,276	2.22	78,692	1,579,968	2.34
1135G	**Turbines and Generators - Total for Parent Account**	2101	60-S3	**146,383,857**	**2,613,973**	**1.79**	**91,265**	**2,705,238**	**1.85**			**146,383,857**	**2,578,944**	**1.76**	**105,549**	**2,684,493**	**1.83**
Grand Rapids 1140G:																	
1140G1	Turbines									2091	75-S3	60,479,918	821,891	1.36	(22,537)	799,354	1.32
1140G2	Generators									2091	45-S3	52,733,707	1,170,688	2.22	(52,693)	1,117,995	2.12
1140G	**Turbines and Generators - Total for Parent Account**	2091	60-S3	**113,213,625**	**2,003,975**	**1.77**	**(36,364)**	**1,967,611**	**1.74**			**113,213,625**	**1,992,579**	**1.76**	**(75,230)**	**1,917,349**	**1.69**
Kettle 1145G:																	
1145G1	Turbines									2111	75-S3	27,147,622	361,172	1.33	3,205	364,377	1.34
1145G2	Generators									2111	45-S3	72,015,762	1,598,750	2.22	8,311	1,607,061	2.23
1145G	**Turbines and Generators - Total for Parent Account**	2111	60-S3	**99,163,384**	**1,693,671**	**1.71**	**23,758**	**1,717,429**	**1.73**			**99,163,384**	**1,959,922**	**1.98**	**11,516**	**1,971,438**	**1.99**
Laurie River 1150G:																	
1150G1	Turbines									2035	75-S3	371,894	10,496	2.82	613	11,109	2.99
1150G2	Generators									2035	45-S3	4,231,242	147,942	3.50	4,990	152,932	3.61
1150G1	Turbines																
1150G	**Turbines and Generators - Total for Parent Account**	2035	60-S3	**4,603,136**	**160,625**	**3.49**	**6,099**	**166,724**	**3.62**			**4,603,136**	**158,438**	**3.44**	**5,603**	**164,041**	**3.56**
Jenpeg 1155G:																	
1155G1	Turbines									2118	75-S3	47,800,851	637,186	1.33	(2,443)	634,743	1.33
1155G2	Generators									2118	45-S3	43,915,520	974,925	2.22	(14,206)	960,719	2.19
1155G	**Turbines and Generators - Total for Parent Account**	2118	60-S3	**91,716,371**	**1,582,037**	**1.72**	**12,804**	**1,594,841**	**1.74**			**91,716,371**	**1,612,111**	**1.76**	**(16,649)**	**1,595,462**	**1.74**
Long Spruce 1170G:																	
1170G1	Turbines									2118	75-S3	63,342,196	842,451	1.33	(17,270)	825,181	1.30
1170G2	Generators									2118	45-S3	79,986,447	1,775,699	2.22	(93,529)	1,682,170	2.10
1170G	**Turbines and Generators - Total for Parent Account**	2118	60-S3	**143,328,643**	**2,453,827**	**1.71**	**(25,472)**	**2,428,355**	**1.69**			**143,328,643**	**2,618,150**	**1.83**	**(110,799)**	**2,507,351**	**1.75**

MANITOBA HYDRO
TABLE 1. SUMMARY OF AVERAGE SERVICE LIFE VERSUS EQUAL LIFE GROUP
PLANT AS OF MARCH 31, 2014

ACCOUNT	ACCOUNT DESCRIPTION	FILED ELG: LIFE SPAN DATE	FILED ELG: SURVIVOR CURVE	FILED ELG: SURVIVING ORIGINAL COST AS OF MARCH 31, 2014	FILED ELG: CALCULATED ANNUAL ACCRUAL AMOUNT	FILED ELG: CALCULATED ANNUAL ACCRUAL RATE (%)	FILED ELG: ANNUAL PROVISION FOR TRUE-UP	FILED ELG: TOTAL DEPRECIATION RELATED TO LIFE EXPENSE	FILED ELG: TOTAL DEPRECIATION RELATED TO LIFE RATE (%)	ASL - COMPONENTIZATION: LIFE SPAN DATE	ASL - COMPONENTIZATION: SURVIVOR CURVE	ASL - COMPONENTIZATION: SURVIVING ORIGINAL COST AS OF MARCH 31, 2014	ASL - COMPONENTIZATION: CALCULATED ANNUAL ACCRUAL AMOUNT	ASL - COMPONENTIZATION: CALCULATED ANNUAL ACCRUAL RATE (%)	ASL - COMPONENTIZATION: ANNUAL PROVISION FOR TRUE-UP	ASL - COMPONENTIZATION: TOTAL DEPRECIATION RELATED TO LIFE EXPENSE	ASL - COMPONENTIZATION: TOTAL DEPRECIATION RELATED TO LIFE RATE (%)
	(1)		(2)	(3)	(4)	(5)=(4)/(3)	(6)	(7)=(4)+(6)	(8)=(7)/(3)		(9)	(10)	(11)	(12)=(11)/(10)	(13)	(14)=(11)+(13)	(15)=(14)/(10)
Limestone 1175G:																	
1175G1	Turbines									2131	75-S3	180,982,160	2,407,063	1.33	43,437	2,450,500	1.35
1175G2	Generators									2131	45-S3	223,347,469	4,958,314	2.22	199,599	5,157,913	2.31
1175G	**Turbines and Generators - Total for Parent Account**	2131	60-S3	**404,329,629**	**7,181,521**	**1.78**	**134,341**	**7,315,862**	**1.81**			**404,329,629**	**7,365,377**	**1.82**	**243,036**	**7,608,413**	**1.88**
Wuskwatim 1180G:																	
1180G1	Turbines									2152	75-S3	2,279,516	30,318	1.33	(170)	30,148	1.32
1180G2	Generators									2152	45-S3	2,372,558	52,671	2.22	(496)	52,175	2.20
1180G	**Turbines and Generators - Total for Parent Account**	2152	60-S3	**4,652,074**	**83,272**	**1.79**	**(581)**	**82,691**	**1.78**			**4,652,074**	**82,989**	**1.78**	**(666)**	**82,323**	**1.77**
Wuskwatim Power Limited Partnership ("WPLP") 1181G:																	
1181G1	WPLP - Turbines									2152	75-S3	73,430,216	976,622	1.33	(95)	976,527	1.33
1181G2	WPLP - Generators									2152	45-S3	76,427,367	1,696,688	2.22	(278)	1,696,410	2.22
1181G	**WPLP - Turbines and Generators - Total for Parent Account**	2152	60-S3	**149,857,582**	**2,682,451**	**1.79**	**(322)**	**2,682,129**	**1.79**			**149,857,583**	**2,673,310**	**1.78**	**(373)**	**2,672,937**	**1.78**
2000J1	Wood Poles and Fixtures										65-R3	98,335,498	1,514,367	1.54	(204,145)	1,310,222	1.33
2000J2	Crossarms										35-R2	18,730,571	535,694	2.86	(117,120)	418,574	2.23
2000J	**Poles and Fixtures - Total for Parent Account**		55-R3	**117,066,069**	**2,279,899**	**1.95**	**(175,193)**	**2,104,706**	**1.80**			**117,066,069**	**2,050,061**	**1.75**	**(321,265)**	**1,728,796**	**1.48**
3100S1	Other Transformers										45-R1.5	80,244,655	1,781,431	2.22	(169,730)	1,611,701	2.01
3100S2	Potential and Current Transformers										60-S0.5	32,245,815	538,505	1.67	(42,387)	496,118	1.54
3100S	**Other Transformers - Total for Parent Account**		50-S1	**112,490,470**	**2,488,670**	**2.21**	**48,344**	**2,537,014**	**2.26**			**112,490,470**	**2,319,936**	**2.06**	**(212,117)**	**2,107,819**	**1.87**
3100T1	Other Interrupting Equipment										50-R2.5	128,502,890	2,570,058	2.00	104,140	2,674,198	2.08
3100T2	Vacuum Circuit Breakers										20-R2.5	13,442,631	664,282	4.94	68,600	732,882	5.45
3100T3	Min Oil and SF6 Breakers										40-R2.5	41,157,542	1,028,939	2.50	59,529	1,088,468	2.64
3100T4	Air Magnetic Breakers										50-R2.5	18,181,824	363,636	2.00	71,600	435,236	2.39
3100T5	Air Blast and Oil Bulk Breakers										100-R2.5	8,760,820	87,608	1.00	6,290	93,898	1.07
3100T	**Interrupting Equipment - Total for Parent Account**		50-R2.5	**210,045,708**	**4,428,834**	**2.11**	**418,260**	**4,847,094**	**2.31**			**210,045,707**	**4,714,523**	**2.24**	**310,159**	**5,024,682**	**2.39**
4000J1	Wood Poles and Fixtures										65-S1	601,525,314	9,263,490	1.54	(1,648,252)	7,615,238	1.27
4000J2	Crossarms										35-R2.5	67,430,774	1,928,520	2.86	(516,735)	1,411,785	2.09
4000J	**Poles and Fixtures - Total for Parent Account**		65-S0.5	**668,956,088**	**11,903,877**	**1.78**	**(1,315,678)**	**10,588,200**	**1.58**			**668,956,088**	**11,192,010**	**1.67**	**(2,164,987)**	**9,027,023**	**1.35**
Breakdown for Existing Account 8000E - 360 Portage - Electro/Mechanical																	
Account#	**Account Description**																
8000E1	360 Portage - Electro/mechanical - Finishes										20-R2.5	13,901,418	695,071	5.00	30,470	725,541	5.22
8000E2	360 Portage - Electro/mechanical - Mechanical/Windows & Other										40-R3	41,266,289	1,031,657	2.50	21,210	1,052,867	2.55
8000E3	360 Portage - Electro/mechanical - Millwork & Elevators										60-R2	9,262,022	154,676	1.67	1,879	156,555	1.69
8000E4	360 Portage - Electro/mechanical - Interior Glaze/Drywall & Electrical										75-R1.5	12,909,669	171,699	1.33	1,544	173,243	1.34
8000E	**360 Portage - Total for Parent Account**		45-R3	**77,339,398**	**1,937,503**	**2.51**	**39,260**	**1,976,763**	**2.56**			**77,339,398**	**2,053,103**	**2.65**	**55,103**	**2,108,206**	**2.73**
				2,887,794,051	**54,284,140**	**1.88**	**(1,617,187)**	**52,666,953**	**1.82**			**2,887,794,050**	**54,895,817**	**1.90**	**(2,967,360)**	**51,928,457**	**1.80**

Note:
Totals May Not Sum Due To Rounding

MANITOBA HYDRO
TABLE 2. SUMMARY OF AVERAGE SERVICE LIFE VERSUS EQUAL LIFE GROUP
NEW PLANT ADDITIONS IN 2019

ACCOUNT	ACCOUNT DESCRIPTION	FORECAST CAPITAL ADDITIONS	ESTIMATED AVERAGE SERVICE LIFE	FILED ELG: LIFE SPAN DATE	FILED ELG: SURVIVOR CURVE	FILED ELG: SURVIVING ORIGINAL COST AS OF MARCH 31, 2019	FILED ELG: CALCULATED ANNUAL ACCRUAL AMOUNT	FILED ELG: CALCULATED ANNUAL ACCRUAL RATE (%)	ASL - COMPONENTIZATION: LIFE SPAN DATE	ASL - COMPONENTIZATION: SURVIVOR CURVE	ASL - COMPONENTIZATION: SURVIVING ORIGINAL COST AS OF MARCH 31, 2019	ASL - COMPONENTIZATION: CALCULATED ANNUAL ACCRUAL AMOUNT	ASL - COMPONENTIZATION: CALCULATED ANNUAL ACCRUAL RATE (%)
					(2)	(3)	(4)	(5)=(4)/(3)		(6)	(7)	(8)	(9)=(8)/(7)
BiPole III - Future HVDC Converter Stations - Riel and Keetawinohk:													
SubStations 3200M Synchronous Condensers and Unit Transformers:													
3200M1	Synchronous Condensers	125,600,000	65 Years						65	R4	125,600,000	1,934,240	1.54
3200M2	Unit Transformers	67,000,000	40 Years						40	R4	67,000,000	1,675,000	2.50
		192,600,000		56	R4	**192,600,000**	**3,659,400**	**1.90**			**192,600,000**	**3,609,240**	**2.00**
SubStations 3200P Converter Equipment			25 Years										
3200P1	HVDC Converter Valves and Valve Cooling Equipment	154,300,000	40-50 Years						25	S4	154,300,000	6,172,000	4.00
3200P2	HVDC Converter Transformers	353,300,000							40	S4	353,300,000	8,832,500	2.50
		507,600,000		35	S4	**507,600,000**	**14,974,200**	**2.95**			**507,600,000**	**15,004,500**	**3.00**
Other Components		**1,974,900,000**											
CEF14	BiPole III Converter Stations	**2,675,100,000**											
		26% *											
	TOTAL BIPOLE III AND KEEYASK FORECAST ADDITIONS					**700,200,000**	**18,633,600**	**2.66**			**700,200,000**	**18,613,740**	**2.66**

* Percentage of Forecast Item for Which Component Breakdown Provided

MANITOBA HYDRO
TABLE 3. SUMMARY OF AVERAGE SERVICE LIFE VERSUS EQUAL LIFE GROUP
NEW PLANT ADDITIONS IN 2020

				FILED ELG					ASL - COMPONENTIZATION				
ACCOUNT	ACCOUNT DESCRIPTION	FORECAST CAPITAL ADDITIONS	ESTIMATED AVERAGE SERVICE LIFE	LIFE SPAN DATE	SURVIVOR CURVE	SURVIVING ORIGINAL COST AS OF MARCH 31, 2020	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE (%)	LIFE SPAN DATE	SURVIVOR CURVE	SURVIVING ORIGINAL COST AS OF MARCH 31, 2020	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE (%)
					(2)	(3)	(4)	(5)=(4)/(3)		(6)	(7)	(8)	(9)=(8)/(7)
BiPole III - Future HVDC Converter Stations - Riel & Keetawinohk:													
SubStations 3200M Synchronous Condensers and Unit Transformers:													
3200M1	Synchronous Condensers	125,600,000	65 Years						65	R4	125,600,000	1,934,240	1.54
3200M2	Unit Transformers	67,000,000	40 Years						40	R4	67,000,000	1,675,000	2.50
		192,600,000		56	R4	**192,600,000**	**3,659,400**	1.90			**192,600,000**	**3,609,240**	**2.00**
SubStations 3200P Converter Equipment													
3200P1	HVDC Converter Valves and Valve Cooling Equipment	154,300,000	25 Years						25	S4	154,300,000	6,172,000	4.00
3200P2	HVDC Converter Transformers	353,300,000	40-50 Years						40	S4	353,300,000	8,832,500	2.50
		507,600,000		35	S4	**507,600,000**	**14,974,200**	2.95			**507,600,000**	**15,004,500**	**3.00**
Other Components		**1,974,900,000**											
CEF14	BiPole III Converter Stations	**2,675,100,000**											
		26% *											
Keeyask - Future Hydraulic Generating Station													
Manitoba Hydro Owned Assets (Interest Capitalized on MH Equity in KHLP Physical Assets)													
Keeyask 1185E Water Control Systems													
1185E1	Water Control Systems	30,700,000	65 Years						65	R4	21,900,000	337,260	1.54
1185E2	Ice, Debris and Public Safety Booms	1,200,000	30 Years						30	R4	1,200,000	39,960	3.33
		31,900,000		65	R4	**23,100,000**	**378,840**	1.64			**23,100,000**	**377,220**	**2.00**
Keeyask 1185G Turbines and Generators													
1185G1	Turbines	17,200,000	75 Years						75	S3	7,400,000	98,420	1.33
1185G2	Generators	17,200,000	50 Years						45	S3	7,400,000	164,280	2.22
		34,400,000		65	S3	**14,800,000**	**244,200**	1.65			**14,800,000**	**262,700**	**2.00**
Keeyask 1185P A/C Electrical Power Systems													
1185P2	Step-up Transformers Manufactured in 1950 or later	2,400,000	40 Years						40	R4	1,000,000	25,000	2.50
1185P3	A/C Electrical Power Systems - Other Equipment	10,600,000	55 Years						55	R4	4,500,000	81,900	1.82
		13,000,000		50	R4	**5,500,000**	**117,150**	2.13			**5,500,000**	**106,900**	**2.00**
Other Components		**286,000,000**											
CEF14	Keeyask GS - Interest on MH Equity	**365,300,000**											
		22% *											
Keeyask Hydropower Limited Partnership Assets (tangible)													
Keeyask (KHLP) 1186E Water Control Systems													
1186E1	KHLP - Water Control Systems	498,800,000	65 Years						65	R4	356,300,000	5,487,020	1.54
1186E2	KHLP - Ice, Debris and Public Safety Booms	20,200,000	30 Years						30	R4	20,200,000	672,660	3.33
		519,000,000		65	R4	**376,500,000**	**6,174,600**	1.64			**376,500,000**	**6,159,680**	**2.00**
Keeyask (KHLP) 1186G Turbines and Generators													
1186G1	Turbines	279,500,000	75 Years						75	S3	119,800,000	1,593,340	1.33
1186G2	Generators	279,500,000	50 Years						45	S3	119,800,000	2,659,560	2.22
		559,000,000		65	S3	**239,600,000**	**3,953,400**	1.65			**239,600,000**	**4,252,900**	**2.00**

Gannett Fleming

MANITOBA HYDRO
TABLE 3. SUMMARY OF AVERAGE SERVICE LIFE VERSUS EQUAL LIFE GROUP
NEW PLANT ADDITIONS IN 2020

ACCOUNT	ACCOUNT DESCRIPTION	FORECAST CAPITAL ADDITIONS	ESTIMATED AVERAGE SERVICE LIFE	FILED ELG: LIFE SPAN DATE	FILED ELG: SURVIVOR CURVE	FILED ELG: SURVIVING ORIGINAL COST AS OF MARCH 31, 2020	FILED ELG: CALCULATED ANNUAL ACCRUAL AMOUNT	FILED ELG: CALCULATED ANNUAL ACCRUAL RATE (%)	ASL - COMPONENTIZATION: LIFE SPAN DATE	ASL - COMPONENTIZATION: SURVIVOR CURVE	ASL - COMPONENTIZATION: SURVIVING ORIGINAL COST AS OF MARCH 31, 2020	ASL - COMPONENTIZATION: CALCULATED ANNUAL ACCRUAL AMOUNT	ASL - COMPONENTIZATION: CALCULATED ANNUAL ACCRUAL RATE (%)
					(2)	(3)	(4)	(5)=(4)/(3)		(6)	(7)	(8)	(9)=(8)/(7)
Keeyask (KHLP) 1186P A/C Electrical Power Systems													
1186P2	Step-up Transformers Manufactured in 1950 or later	38,800,000	40 Years						40	R4	16,600,000	415,000	2.50
1186P3	A/C Electrical Power Systems - Other Equipment	172,200,000	55 Years						55	R4	73,800,000	1,343,160	1.82
		211,000,000		50	R4	**90,400,000**	**1,925,520**	2.13			**90,400,000**	**1,758,160**	**2.00**
Other Components		**4,639,600,000**											
CEF14	Keeyask GS - Interest on MH Equity	**5,928,600,000**											
		22% *											
	TOTAL PLANT					**1,450,100,000**	**31,427,310**	**2.17**			**1,450,100,000**	**31,531,300**	**2.17**

* Percentage of Forecast Item for Which Component Breakdown Provided

MANITOBA HYDRO
TABLE 4. SUMMARY OF AVERAGE SERVICE LIFE VERSUS EQUAL LIFE GROUP
NEW PLANT ADDITIONS IN 2021

ACCOUNT	ACCOUNT DESCRIPTION	FORECAST CAPITAL ADDITIONS	ESTIMATED AVERAGE SERVICE LIFE	ELG (AGGREGATE LEVEL - COMPARABLE ACCOUNTS): LIFE SPAN DATE	ELG: SURVIVOR CURVE (2)	ELG: SURVIVING ORIGINAL COST AS OF MARCH 31, 2021 (3)	ELG: CALCULATED ANNUAL ACCRUAL AMOUNT (4)	ELG: CALCULATED ANNUAL ACCRUAL RATE (%) (5)=(4)/(3)	ASL (COMPONENTIZATION - COMPARABLE SUB-COMPONENTS FOR ACCOUNTS): LIFE SPAN DATE	ASL: SURVIVOR CURVE (6)	ASL: SURVIVING ORIGINAL COST AS OF MARCH 31, 2021 (7)	ASL: CALCULATED ANNUAL ACCRUAL AMOUNT (8)	ASL: CALCULATED ANNUAL ACCRUAL RATE (%) (9)=(8)/(7)
BiPole III - Future HVDC Converter Stations - Riel & Keetawinohk:													
SubStations 3200M Synchronous Condensers and Unit Transformers:													
3200M1	Synchronous Condensers	125,600,000	65 Years						65	R4	125,600,000	1,934,240	1.54
3200M2	Unit Transformers	67,000,000	40 Years						40	R4	67,000,000	1,675,000	2.50
		192,600,000		56	R4	**192,600,000**	**3,659,400**	1.90			**192,600,000**	**3,609,240**	**2.00**
SubStations 3200P Converter Equipment													
3200P1	HVDC Converter Valves and Valve Cooling Equipment	154,300,000	25 Years						25	S4	154,300,000	6,172,000	4.00
3200P2	HVDC Converter Transformers	353,300,000	40-50 Years						40	S4	353,300,000	8,832,500	2.50
		507,600,000		35	S4	**507,600,000**	**14,974,200**	2.95			**507,600,000**	**15,004,500**	**3.00**
Other components		**1,974,900,000**											
CEF14	BiPole III Converter Stations	**2,675,100,000**											
		26% *											
Keeyask - Future Hydraulic Generating Station													
Manitoba Hydro Owned Assets (Interest Capitalized on MH Equity in KHLP Physical Assets)													
Keeyask 1185E Water Control Systems													
1185E1	Water Control Systems	30,700,000	65 Years						65	R4	30,700,000	472,780	1.54
1185E2	Ice, Debris and Public Safety Booms	1,200,000	30 Years						30	R4	1,200,000	39,960	3.33
		31,900,000		65	R4	**31,900,000**	**523,160**	1.64			**31,900,000**	**512,740**	**2.00**
Keeyask 1185G Turbines and Generators													
1185G1	Turbines	17,200,000	75 Years						75	S3	17,200,000	228,760	1.33
1185G2	Generators	17,200,000	50 Years						45	S3	17,200,000	381,840	2.22
		34,400,000		65	S3	**34,400,000**	**567,600**	1.65			**34,400,000**	**610,600**	**2.00**
Keeyask 1185P A/C Electrical Power Systems													
1185P2	Step-up Transformers Manufactured in 1950 or later	2,400,000	40 Years						40	R4	2,400,000	60,000	2.50
1185P3	A/C Electrical Power Systems - Other Equipment	10,600,000	55 Years						55	R4	10,600,000	192,920	1.82
		13,000,000		50	R4	**13,000,000**	**276,900**	2.13			**13,000,000**	**252,920**	**2.00**
Other components		**286,000,000**											
CEF14	Keeyask GS - Interest on MH Equity	**365,300,000**											
		22% *											
Keeyask Hydropower Limited Partnership Assets (tangible)													
Keeyask (KHLP) 1186E Water Control Systems													
1186E1	KHLP - Water Control Systems	498,800,000	65 Years						65	R4	498,800,000	7,681,520	1.54
1186E2	KHLP - Ice, Debris and Public Safety Booms	20,200,000	30 Years						30	R4	20,200,000	672,660	3.33
		519,000,000		65	R4	**519,000,000**	**8,511,600**	1.64			**519,000,000**	**8,354,180**	**2.00**

Gannett Fleming

MANITOBA HYDRO
TABLE 4. SUMMARY OF AVERAGE SERVICE LIFE VERSUS EQUAL LIFE GROUP
NEW PLANT ADDITIONS IN 2021

ACCOUNT	ACCOUNT DESCRIPTION	FORECAST CAPITAL ADDITIONS	ESTIMATED AVERAGE SERVICE LIFE	ELG (AGGREGATE LEVEL - COMPARABLE ACCOUNTS) LIFE SPAN DATE	ELG SURVIVOR CURVE (2)	ELG SURVIVING ORIGINAL COST AS OF MARCH 31, 2021 (3)	ELG CALCULATED ANNUAL ACCRUAL AMOUNT (4)	ELG CALCULATED ANNUAL ACCRUAL RATE (%) (5)=(4)/(3)	ASL (COMPONENTIZATION - COMPARABLE SUB-COMPONENTS FOR ACCOUNTS) LIFE SPAN DATE	ASL SURVIVOR CURVE (6)	ASL SURVIVING ORIGINAL COST AS OF MARCH 31, 2021 (7)	ASL CALCULATED ANNUAL ACCRUAL AMOUNT (8)	ASL CALCULATED ANNUAL ACCRUAL RATE (%) (9)=(8)/(7)
Keeyask (KHLP) 1186G Turbines and Generators													
1186G1	Turbines	279,500,000	75 Years						75	S3	279,500,000	3,717,350	1.33
1186G2	Generators	279,500,000	50 Years						45	S3	279,500,000	6,204,900	2.22
		559,000,000		65	S3	**559,000,000**	**9,223,500**	1.65			**559,000,000**	**9,922,250**	**2.00**
Keeyask (KHLP) 1186P A/C Electrical Power Systems													
1186P2	Step-up Transformers Manufactured in 1950 or later	38,800,000	40 Years						40	R4	38,800,000	970,000	2.50
1186P3	A/C Electrical Power Systems - Other Equipment	172,200,000	55 Years						55	R4	172,200,000	3,134,040	1.82
		211,000,000		50	R4	**211,000,000**	**4,494,300**	2.13			**211,000,000**	**4,104,040**	**2.00**
Other components		**4,639,600,000**											
CEF14	Keeyask GS - Interest on MH Equity	**5,928,600,000** 22% *											
	TOTAL PLANT					**2,068,500,000**	**42,230,660**	**2.04**			**2,068,500,000**	**42,370,470**	**2.05**

* Percentage of Forecast Item for Which Component Breakdown Provided

Gannett Fleming

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Section:	Tab 5: App 5.6	Page No.:	Appendix 11.49, page II-3
Topic:	Financial Results and Forecast		
Subtopic:	Depreciation Expense		
Issue:	ASL vs ELG		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro's head office building was included in the accounts tested by Gannett Fleming.

QUESTION:

a) Please explain why a head office account 'Buildings 360 Portage-Electro/mechanical' was utilized in the analysis and how it is representative of the plant in-service of a hydroelectric utility subject to depreciation based on the stated criteria for selecting representative sample components for extrapolation purposes.

b) Please provide the supporting calculations for the extrapolation of a $3.5 million difference in depreciation expense related to the existing plant in service.

c) Please provide an alternative extrapolation of the depreciation expense related to net plant removing the building account 360 portage – Electro/Mechanical from the testing an compare the extrapolated results with that represented in the study.

RATIONALE FOR QUESTION:

To explore depreciation expense.

RESPONSE:

a) In order to perform a comparison of the impacts of a greater level of componentization under the ASL method as compared to the ELG method, a broad range of asset types is required. This ensures the conclusions drawn from the study are representative of Manitoba Hydro's asset base. The 360 Portage Head Office location is representative of the Corporation's administrative building asset category.

b) The supporting calculations for the extrapolation of the difference between the ASL and ELG depreciation results is as follows:

	('000's)	
Difference Between the ELG and ASL Depreciation Results	$	738
March 31, 2014 Surviving Original Asset Base Tested	$	2,887,794
March 31, 2014 Manitoba Hydro Total Surviving Original Asset Base	$	14,230,426
Extrapolation across total Manitoba Hydro Surviving Original Asset Base*	$	3,639

* ($738 x $14,230,426) / $2,887,794

Given that this test was performed on a sample basis, Manitoba rounded the balances for determining the extrapolated amount referenced in Appendix 11.49 of $3.5 million.

c) Please see below for an extrapolation of the depreciation expense related to net plant assuming the removal of the building account 360 portage – Electro/Mechanical from the testing:

	('000's)	
Difference Between the ELG and ASL Depreciation Results less 360 Portage	$	870
March 31, 2014 Surviving Original Asset Base Tested less 360 Portage	$	2,810,455
March 31, 2014 Manitoba Hydro Total Surviving Original Asset Base	$	14,230,426
Extrapolation across total Manitoba Hydro Surviving Original Asset Base*	$	4,405

* ($870 x $14,230,426) / $2,810,794

The extrapolated amount for this scenario would be approximately $4.4 million.

Section:	Tab 5: App 5.6	Page No.:	Appendix 11.49
Topic:	Financial Results and Forecast		
Subtopic:	Depreciation Expense		
Issue:	ASL vs ELG		

PREAMBLE TO IR (IF ANY):

The Transmission Lines for the project have a capital cost of $1.7 billion and represents about 36% of the capital costs of Bipole III. The analysis tested $700 million or 26% of the $2.7 billion converter station costs representing about 15% of the total project costs for extrapolation purposes. Metal Towers and Concrete Poles appears to be the largest account group in the Transmission Depreciation Accounts.

QUESTION:

a) Please identify the account groups the Bipole III transmission lines are proposed to be depreciated under ELG and the proposed rate.

b) Please indicate what additional component groups Metal Towers and Concrete Poles would need to be broken down into for ASL based IFRS compliant. Provide the respective life span dates, survivor curve and annual accrual effective depreciation rate.

c) Please provide examples of other Utilities' IFRS-compliant breakdown of Transmission Lines for depreciation purposes.

d) Please indicate what the Metal Tower and Concrete Poles ASL based rate would be excluding the 25% Net Salvage and compare this with the 1.23% ELG based rate

e) Please update the comparative analysis including the Metal Towers and Concrete Poles in the analysis.

RATIONALE FOR QUESTION:

To test the extrapolation analysis

RESPONSE:

a) The depreciation charges for the Bipole III transmission line will be recognized in all the account groups included in the Transmission category as listed in the 2014 Depreciation Study in Attachment 2 of Appendix 5.6., with the exception of the ground line treatment component.

b) As identified on page 12 of Appendix 11.49 of the application, Metal Towers and Concrete Poles could potentially be broken down further between the towers and the concrete footings upon which they are fastened. The concrete footings were identified as a likely component that could be separated from the metal towers given recent years experience with having to repair and replace many cracked / sunken footings. The costs to install and repair the footings are material and recent years experience indicates they are not lasting as long as the metal towers that are fastened to them.

The detailed analysis required to provide the respective average service life, survivor curve and annual accrual effective depreciation rate has not been performed as Manitoba Hydro is not using an IFRS compliant ASL method upon transition to IFRS. Similar to other significant asset components, the information required to perform this analysis is not readily available as historical plant costs for the installation of the footings were not typically captured separately from the costs of installing the towers.

c) Manitoba Hydro is only familiar at a detailed level with its own circumstances with respect to its transmission system costs and under which components such costs are recorded. Component groupings have been supplied in the response to MIPUG-MH-I-16 (a) for utilities such as BC Hydro, AltaLink and SaskPower which are reporting under IFRS.

d) The Metal Tower and Concrete Poles CGAAP ASL based depreciation rate excluding the 25% Net Salvage is 1.16% compared the 1.23% ELG based rate.

Please see the response to PUB/MH-II-21b and PUB/MH-II-21c for a discussion regarding the impacts associated with using the CGAAP ASL method of depreciation for rate setting purposes.

e) The analysis in Appendix 11.49 shows a comparison of an IFRS compliant ASL method to the ELG method. As indicated in part (b) to this response, the detailed analysis has not been performed in order to be able to separate the costs of the Metal Towers and Concrete Poles component between the towers and concrete footings. As such, the information required to provide an update to the comparative analysis in Appendix 11.49 is not available.

Section:	Appendix 5.6	Page No.:	
Topic:	Depreciation		
Subtopic:	Peer Reviewed Utilities		
Issue:			

PREAMBLE TO IR (IF ANY):

MH Exhibit #57 from the 2012/13 & 2013/14 GRA provided the utilities that Mr. Kennedy reviewed and relied upon in the selection of average service life recommendations. PUB/MH I-85 indicated the depreciation methodology employed in other Canadian jurisdictions at the time of the 2012/13 & 2013/14 GRA and compared ASL and ELG.

QUESTION:

Please update MH Exhibit #57 in providing the peer information for the companies relied upon by Gannett Fleming in the 2014 Depreciation Study, with a copy of the summary of results from each of the above studies.

RATIONALE FOR QUESTION:

MIPUG is reviewing the depreciation study including any changes that have occurred since the 2010 depreciation study.

RESPONSE:

The following response was provided by Gannett Fleming.

The average service life estimates for the following eight (8) regulated Canadian utilities were reviewed by Mr. Kennedy and relied upon in the selection of average service life recommendations:

- AltaLink LP – 2014 Depreciation study incorporating forecast plant balances as at December 31, 2016

- ATCO Electric – 2010 Depreciation study incorporating plant balances as at December 31, 2008
- BC Hydro – 2005 Depreciation Study incorporating Plant Accounting information through March 31, 2005
- FortisAlberta – 2011 Study incorporating plant balances through December 31, 2010
- FortisBC Inc – 2010 Depreciation Study incorporating plant balances through December 31, 2009
- Newfoundland and Labrador Hydro – 2009 Depreciation Study incorporating plant balances through December 31, 2007
- Ontario Power Generation – 2013 Depreciation Study incorporating plant balances through December 31, 2012
- SaskPower - 2010 Depreciation Study incorporating plant balances through December 31, 2009

A copy of the summary of results from each of the above studies is provided as an attachment to this response.

ALTALINK LP

TABLE 1A. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
AS OF DECEMBER 31, 2013
"COST OF REMOVAL"

ACCOUNT	DESCRIPTION	ESTIMATED SURVIVOR CURVE	ESTIMATED NET SALVAGE PERCENTAGE	SURVIVING ORIGINAL COST AS OF 12/31/2013	CALCULATED ACCRUED DEPRECIATION	ANNUAL ACCRUAL AMOUNT	ANNUAL ACCRUAL RATE	ANNUAL PROVISION FOR TRUE-UP	TOTAL DEPRECIATION EXPENSE	TOTAL DEPRECIATION RATE
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)= (7)/(5)	(9)	(10)=(7)+(9)	(11)=(10)/(5)
TRANSMISSION PLANT										
352.00	STRUCTURES AND IMPROVEMENTS	50-R2.5	(40)	200,703,062	13,728,337	1,908,105	0.95	293,825	2,201,930	1.10
353.00	STATION EQUIPMENT	47-R2	(40)	1,666,212,377	137,114,793	17,541,117	1.05	2,499,965	20,041,082	1.20
353.10	SYSTEM COMMUNICATION AND CONTROL	25-L1.5	(25)	535,906,782	39,850,165	6,424,390	1.20	1,537,001	7,961,391	1.49
354.00	TOWERS AND FIXTURES	53-R1.5	(25)	877,972,224	32,017,348	6,320,152	0.72	519,207	6,839,359	0.78
355.00	POLES AND FIXTURES	50-R2.5	(100)	634,220,801	109,071,757	15,083,790	2.38	(290,054)	14,793,736	2.33
356.00	OVERHEAD CONDUCTORS AND DEVICES	65-R4	(40)	675,428,598	54,709,096	4,373,730	0.65	895,323	5,269,053	0.78
358.00	UNDERGROUND CONDUCTORS AND DEVICES	50-R5	(10)	53,898,963	278,275	109,953	0.20	5,846	115,799	0.21
	TOTAL TRANSMISSION PLANT			**4,644,342,807**	**386,769,771**	**51,761,237**		**5,461,112**	**57,222,349**	**1.23**

ATCO ELECTRIC

TABLE 1. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
AS OF DECEMBER 31, 2008
"LIFE ANALYSIS"

Account	Description	Estimated Survivor Curve	Estimated Net Salvage	Surviving Original Cost at 12/31/2008	Calculated Accrued Depreciation	Annual Accrual Amount	Annual Accrual Rate
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(7)/(5)
Transmission Plant							
451.0	Land Rights	75-R3	0	20,674,833.12	4,779,383	304,031	1.47
453.0	Poles and Fixtures	55-R3	(90)	275,251,396.63	78,206,556	5,432,800	1.97
454.0	Overhead Conductors - Poles	60-R4	(50)	155,046,283.70	53,927,986	2,693,090	1.74
454.1	Overhead Conductor - Towers	60-R4	(20)	49,222,215.48	14,823,485	860,794	1.75
455.0	Towers and Fixtures	50-R4	(25)	117,731,599.25	25,341,593	2,480,485	2.11
457.0	Substation Equipment	53-R3	(10)	621,655,247.31	169,527,938	12,792,758	2.06
Total Transmission Plant				1,239,581,575.49	346,606,941.00	24,563,958	
McNeill Converter Station							
451.02	Land Rights	45-R4 *	0	21,201.65	10,302	515	2.43
453.02	Poles and Fixtures	45-R3 *	(2)	126,968.70	62,086	3,171	2.50
454.02	Overhead Conductors - Poles	45-R3 *	(2)	119,137.24	58,091	2,979	2.50
457.02	Substation Equipment	45-R2.5 *	(2)	42,907,280.50	16,454,977	1,234,004	2.88
Total McNeill Converter				43,174,588.09	16,585,456.00	1,240,669	
Distribution Plant							
471.0	Land Rights	75-R3	0	37,948,212.21	5,775,999	569,543	1.50
473.0	Poles Towers and Fixtures	45-R2.5	(50)	503,211,225.25	137,416,832	12,542,591	2.49
474.0	Overhead Conductor	55-R2.5	(65)	315,005,840.13	74,947,596	6,537,604	2.08
474.1	Services - Overhead	50-R4	0	26,155,802.26	9,225,562	539,031	2.06
475.0	Underground Conductor	55-R4	(10)	201,691,265.19	35,646,788	3,871,618	1.92
475.1	Services - Underground	50-R3	0	30,139,904.65	5,697,316	670,714	2.23
476.1	Meters	20-R1.5 **	0	46,831,216.30	25,370,068	2,679,330	5.72
476.12	Automated Meter Reading	15-R2.5	0	60,856,105.78	36,641,736	3,873,876	6.37
477.1	Substation Equipment	50-R3	(5)	22,136,408.14	9,045,852	463,385	2.09
478.1	Street Lighting and Signal Systems	43-R4	(10)	52,324,807.53	15,728,856	1,263,777	2.42
478.2	Sentinel Lights	31-R1	20	3,366,362.04	1,820,613	101,922	3.03
479.1	Line Transformers	40-R2.5	5	366,774,173.69	96,287,671	10,352,577	2.82
Total Distribution Plant				1,666,441,323.17	453,604,889.00	43,465,968	
General Plant							
482.0	Structures and Improvements	55-R3	(5)	68,535,159.23	16,757,221	1,368,559	2.00
483.0	Office Furniture and Equipment	15-R3	0	8,530,832.37	2,783,202	599,493	7.03
483.2	Computer Hardware	5-S0.5	0	409,167.71	223,023	62,140	15.19
484.1	Transportation Equipment-Category 1	10-L1.5	10	292,550.57	154,159	28,143	9.62
484.2	Transportation Equipment-Category 2	12-L1	10	24,525,454.04	8,526,821	2,447,047	9.98
484.3	Transportation Equipment-Category 3	25-R3	20	37,064,319.83	9,821,302	1,600,496	4.32
484.4	Transportation Equipment-Category 4	12-R2	20	1,267,002.49	438,536	115,232	9.09
485.0	Tools and Work Equipment	10-R2	0	12,249,310.45	5,278,517	1,272,316	10.39
486.0	Communication Equipment	25-R2	0	95,408,346.00	43,337,782	3,930,036	4.12
488.2	Company Houses	12-L0	85	737,086.76	493,220	45,818	6.22
Total General Plant				249,019,229.45	87,813,783.00	11,469,280	
Total Utility Plant in Service				3,198,216,716.20	904,611,069	80,739,875	2.52

* Indicates use of a life span expiring at June 30, 2035.

** Indicates use of a life span expiring at June 30, 2020.

BC Hydro
TABLE 1B - Summary of Existing Components
Profile ID's for Assets Operated or Primarily Operated by BCTC

Profile ID	Description	Estimated Life
11602	Easement/right of way	N/A
11626	Land Rights,Finite Life, 20Yrs	20
11701	Clearing-Transmission	100
11901	Yard Surfacing	35
12001	Trail, Caterpillar	50
12301	Pad, Helicopter	25
12402	Landscaping	25
21102	Erosion Donut &/Or Bank	25
21103	Debris/Avalance Deflector	25
22006	Equipment Shelter	10
25101	Structure - Steel Support	65
25102	Structure, Support, Wood	30
25202	Pole Structures	50
25203	Towers	65
25301	Foundations	40
25401	Trenches and Ducts	50
25502	Ductbanks > 60Kv	50
42201	Resistor - Load Breaking	25
51002	Condenser - Synchronous, Static	40
52102	Transformer - Auto / Bulk System	45
52103	Transformer - Power > 100 Mva	40
52104	Transformer - Power < 100 Mva	45
52106	Transformer - Power - Composite Pool	45
52301	Reactor - Oil	25
52302	Reactor - Dry Type	40
52303	Reactor - Composite Pool	40
52401	Transformer - Oil / 69 Kv & Above	40
52402	Transformer - Gas / Sf6 / 69 Kv & Above	40
52403	Oil, < 69 Kv	35
52404	Transformer - Current, Encaps	45
52405	Transformer - Current, Composite Pool	50
52406	Comb Ct & Vt Transformer	40
52501	Transformer,Voltage,Capacitor	35
52502	Transformer,Voltage,Oil-Fill	40
52503	Transformer,Voltage,Gas-Fill	50
52504	Transformer,Voltage,Encaps.	45
52505	Transformer,Volt,Comp. Pool	40
53101	Capacitor - Shunt	30
53201	Capacitor - Series	35
53202	Metal Oxide Varister (Mov)	35
53301	Capacitor - Coupling	35

BC Hydro
TABLE 1B - Summary of Existing Components
Profile ID's for Assets Operated or Primarily Operated by BCTC

Profile ID	Description	Estimated Life
54102	Breakers - Gas (Sf6) 12/25 Kv	30
54103	Breakers - Bulk/Mon Oil/Air Blast	45
54104	Breakers - Gas (Sf6) 69 To 500 Kv	45
54105	Breakers - Composite Pool	35
54201	Use Individual Disconnect Caus	40
54203	Disconnect - 3 Phase - 12/25 Kv	35
54204	Disconnect - 3 Phase - 69-230 Kv	35
54205	Disconnect - 3 Phase - 500 Kv	35
54401	Switchgear - Metalclad	30
54501	Circuit Recloser	40
54601	Circuit Switcher	30
55101	Overhead Conductor > 60 kV	60
55103	Line Disconnect Switches	25
55302	Cable - Underground > 60 Kv	40
55303	Cable - Submarine > 60 Kv	45
55401	Buswork and Station Conductor	60
55501	Grounding Systems	40
56001	Insulators	55
57001	Surge Arrestor	30
58001	Converter	30
58002	Inverter	30
58101	Var Compensator - Static	40
58201	Resistor, Anode Damping	25
59101	Regulator - Feeder Circuit	30
59201	Charger System, Battery	20
59301	Storage Batteries, Bank	20
59601	Metering, Dcp, Trolleys	35
61001	Fencing	25
65001	Panels/Cubicles, P&C	20
65101	Fault Locating& Reporting	20
67001	Liner, Pvc, Spill Containment	35
67005	Oil Spill Containment	35
67006	Containment System, Oil Spill	35
68001	Carrier System, Power Line	15
68101	Antennae & Waveguide,Microwave	20
68201	Control Center - Master Equipment	12
68202	Terminal Unit - Remote	20
68203	Integrated Control/Data(Icda)	5
68302	Radio - Microwave - Digital	35
68303	Microwave, Conversion Only	20
68401	Multiplex Device, Analog	5

BC Hydro
TABLE 1B - Summary of Existing Components
Profile ID's for Assets Operated or Primarily Operated by BCTC

Profile ID	Description	Estimated Life
68402	Multiplex Device - Digital	20
68503	Radio Equipment, Protection	25
68601	Protection Tone System	20
68602	Digital Teleprotection System	20
68701	Wave Trap / Line Trap	20
68801	Fibre Optic System	20
70001	Cable, Entrance Protection	20
70102	Accelerometers	20
70103	Seismic Monitoring Equipment	20
73001	Cooling System - Air	25
75101	Drier, Air	25
75103	Piping, Stainless Steel	40
75201	Tanks, Steel, Air/Fuel	30
75202	Tank,Fibrglas,Dbl Bottom,Fuel	30
75204	Tanks - Concrete	30
82510	Railcars	35
89001	Intangible/Franchise/Consent	10
89501	Animal Preventative Equipment	20
99404	Transmission - Contributions in Aid	40

BC Hydro
TABLE 1C - Summary of Existing Components
Burrard Thermal Generation Plant

Profile ID	Description	Estimated Life
30101	Boilers, Casing	30
30102	Boiler. Insulation	30
30103	Roof, Boiler	30
30201	Waterwall, Boiler	30
30203	Superheater, High Temp	30
30204	Superheater - Low Temp	30
30205	Reheater, Boiler	30
30301	Header - Drum	40
30501	Piping - High Pressure	40
30601	Fan - Forced Draft	30
30602	Breaching - Flue System	30
30603	Stack, Flue Gases	30
30604	Preheater, Air	30
30605	Burner - Fuel	15
30606	Instrumentation - Boiler	30
30608	Control System, Feedwater	15
30609	Seals - Crown	30
30610	Control System, Fuel	15
30611	Desuperheater System	15
30612	Refractory, Boiler	20
30613	Boiler, Package	30
30801	Transfer System, Ammonia	20
30802	Water Deluge System, Ammonia	30
30803	Vapouriser, Ammonia	20
30804	Compressor, Vapour, Ammonia	15
30805	Piping System, Ammonia	30
30901	Monitoring Equipment - Continuous Emissions	10
30902	Reporting System, Cem	10
30903	Delivery System - Ammonia - Scr	30
30904	Catalyst - Scr	10
31001	Water Intake / Discharge Structure	50
31002	Protection, Cathodic	20
31003	Gates, Inlet/Outlet	30
31004	Screens - Intake	20
31005	Conduit, Intake/Discharge	50
33001	Heat Exchanger, Shell & Tube	30
33002	Pump & Motor	30
33004	Condenser, Boiler	30
34002	Casing Cylinder	30
34004	Turbine - Composite Pool	30
34005	Coils - Stator	30
34006	Rotor / Generator - Thermal	30
34007	Generator - Composite Pool - Thermal	30
34008	Supervisory System, Turbine	20
34009	Cooling System - Hydrogen	30
34015	Turbine Blades Sets	15

BC Hydro
TABLE 1A - Summary of Existing Components
Profile ID's for Assets Owned and Operated by BC Hydro

Profile ID	Description	Estimated Life
11501	Land, and Land Rights (ID's 11501, 11601, and 11604)	N/A
11801	Recreation Facilities	20
12002	Roads - Paved and Gravel	50
12005	Roads and Trails, Composite Pool	50
12101	Tracks, Railway	40
12201	Bridge, Wood	25
12202	Bridge - Steel	46-R3
12203	Bridge - Concrete	75-R2
12401	Drainage System, Yard	50
12501	Wall, Retaining, Steel	50
12502	Wall, Retaining, Concrete	100
21001	Dam - Embankment / Concrete	100-R4
21002	Dam - Crib / Wooden	35-L3
21101	Dike - Protective	100
21102	Erosion Donut &/Or Bank	25-R2
21901	Roofs	30-R1.5
22001	Plant - Concrete Or Steel	50
22002	Commercial - Concrete Or Steel	50-R2.5
22003	Powerhouse - Integral With Dam	100-R4
22004	Building - Wood	15-R1
22005	Building - Composite Pool	60-R2
22006	Equipment Shelter	10-R0.5
22101	Office Trailer / Mobile Home	23-R1
22201	Leasehold Improvements	5
22202	Leashold Improvements	10
23001	Spillway - Separate From Dam	75-R2
23101	Intake Structure - Power	100-R4
23201	Penstock - Steel	75-R4
23202	Penstock - Concrete	100-R4
23203	Penstock - Wood	50-S3
23302	Tank - Surge / Steel	50-R3
23401	Tailrace	100-R3
23501	Canal	100-R3
23601	Stoplogs - Steel	60-R3
23602	Stoplogs, Wood	25
23603	Hoist - Gate	55-R4
23604	Gate	40-R2.5
23605	Gates, Embedded Components	40
23606	Inlet Valves, Penstock & Turbi	50
23701	Trash Racks	50-R2.5
23801	Cranes	60-R3
23901	Fishways - Steel	50-R2.5
23902	Fishways, Concrete	100
24001	Navigation Locks	100
24002	Navigation Lock Gates - Controls	20
24003	Motor	20

BC Hydro
TABLE 1A - Summary of Existing Components
Profile ID's for Assets Owned and Operated by BC Hydro

Profile ID	Description	Estimated Life
24101	Sluiceway - Separate From Dam	100-R3
24201	Tunnels	100-R4
24301	Slope Stabilization	100
24401	Dock / Wharf	25
24402	Ramp, Boat/Barge	20
25201	Poles	50-L4
25501	Ductbanks	50-R3
25502	Ductbanks > 60Kv	50-R3
25601	Barriers & Enclosures	50
25701	Capacitor, <60 Kv	30
30206	Desuperheater/Attemperator	10
30401	Valves, Safety	30
30607	Asbestos Abatement	30
30701	Equipment, Water Treatment	40
31006	Valves	30
31007	Turbine / Penstock Inlet Valves	50-R3
33005	Condenser Air Removal System	15
41001	Runner - Water Wheel	50-R2
41002	Governor System - Turbine	50-R4
41003	Casing - Embedded / Spiral Case	50-R4
41004	Shaft - Turbine	50-R4
41005	Gates, Wicket	50
41006	Cover - Head	50-R4
41007	Turbine - Hydro Composite Pool	50-R4
41008	Bearings For Wicket Gate	25
41501	Draft Tube Water Depression System	25-R3
41601	Unwatering System	25-R3
41701	Turbine Air Injection Blower	25
42001	Coils - Stator	30-R2.5
42002	Rotor - Generator	50-R4
42003	Generator - Composite Pool (Hydro)	50-R3
42101	Excitor - Rotary	40-R1.5
42102	Excitor - Static	40-R4
42104	Excitor - Composite Pool	40-R4
42201	Resistor - Load Breaking	25-R3
42501	Piping, Water Cooling System	40
42502	Monitoring System, Cooling	20
46501	Cooling System, Water	15
46502	Engine - Internal Combustion	25-R2.5
46701	Heat Exchanger	30-R3
47201	Turbine - Gas	25-R3
47401	Fuel System	40
48001	Coils, Stator	40
48002	Rotor, Generator	40
48003	Generator - Composite Pool	30-R2
48004	Generator, Diesel	30
49001	Pump	20-R0.5

BC Hydro
TABLE 1A - Summary of Existing Components
Profile ID's for Assets Owned and Operated by BC Hydro

Profile ID	Description	Estimated Life
49002	Motor	30
49201	Vacuum System	25
51001	Condensor,Synchronous,Rotary	50
51002	Condenser - Synchronous, Static	40-S4
52101	Transformer - Generator / Set-Up	40-R4
52102	Transformer - Auto / Bulk System	45-R4
52103	Transformer - Power > 100 Mva	40-R3
52104	Transformer - Power < 100 Mva	45-R3
52105	Transformer - Station Service	40-R3
52106	Transformer - Power - Composite Pool	45-R3
52201	Distribution Transformers	35-R2
52301	Reactor - Oil	25-R1.5
52302	Reactor - Dry Type	40-R4
52303	Reactor - Composite Pool	40-R4
52401	Transformer - Oil / 69 Kv & Above	40-R4
52402	Transformer - Gas / Sf6 / 69 Kv & Above	40-R1.5
52404	Transformer - Current, Encaps	45-R3
52405	Transformer - Current, Composite Pool	50-R4
52601	Mobile Substations	25-R3
53101	Capacitor - Shunt	30-S4
53201	Capacitor - Series	35-R4
53202	Metal Oxide Varister (Mov)	35-R1
53301	Capacitor - Coupling	35-R4
54101	Breaker,Air/Magnetic	20
54102	Breakers - Gas (Sf6) 12/25 Kv	30-R3
54103	Breakers - Bulk/Mon Oil/Air Blast	45-R4
54104	Breakers - Gas (Sf6) 69 To 500 Kv	45-R2.5
54105	Breakers - Composite Pool	35-L4
54202	Disconnect, 1 Phase, Hookstick	30
54203	Disconnect - 3 Phase - 12/25 Kv	35-R2.5
54204	Disconnect - 3 Phase - 69-230 Kv	35-R2.5
54205	Disconnect - 3 Phase - 500 Kv	35-R2.5
54401	Switchgear - Metalclad	30-R3
54601	Circuit Switcher	30-R4
55102	Overhead Conductor	45-R1
55201	Overhead Conductor Services < 60kV	45
55202	Ug Conductor Services < 60 Kv	45
55301	Underground / Submarine Cable	40-R3
55302	Cable - Underground > 60 Kv	40-R4
55303	Cable - Submarine > 60 Kv	45-R4
55304	Cable, Submarine < 60 Kv	35
58101	Var Compensator - Static	40-R3
58901	Power Supply, Solar Panel	10
59001	Power Supply - Uninterruptible	15-R3
59101	Regulator - Feeder Circuit	30-R3
59401	Meters	25-R2
59402	Meters, Transmission	30

BC Hydro
TABLE 1A - Summary of Existing Components
Profile ID's for Assets Owned and Operated by BC Hydro

Profile ID	Description	Estimated Life
59501	Street Lights	40-R3
59502	Street Lights,Dist. , Leased	40
61101	Alarm/Security System	20
61201	Booms, Floating	15
61202	Booms, Floating Cedar	25
61203	Booms, Oil Containmnet	15
62001	Fire Protection	25
62501	Firefighting Equipment	25
63001	Exercise Equipment	5
67003	Containment Facility, Concrete	50
67004	Spill Pond, Natural	25
67005	Oil Spill Containment	35-R3
68201	Control Center - Master Equipment	12-R2
68204	Distributed Control System	20-R2
68205	Global Positioning Equipment	10
68301	Radio,Microwave,Analog	35
68302	Radio - Microwave - Digital	35-R4
68402	Multiplex Device - Digital	20-S3
68501	Radio Systems, Uhf/Vhff	35
68502	Mobile Dispatch System	5
68901	Telephone Equipment - Pbx/Pax	20-R2
68903	Tel Equip, Monitoring System	5
68904	Telephone System, Cellular	5
70101	Hydrometeorological Equipment	15
70103	Seismic Monitoring Equipment	20-R2
73001	Cooling System - Air	25-S4
74001	Motor - Generator Sets	35-S4
75102	Piping/Valving, Steel	20
75104	Compressor - Air	25-R3
75203	Tanks - Air Stainless/Oil Steel	30-R2
75204	Tanks - Concrete	30-R2
75205	Tanks, Wood	25
75301	Water Supply System	40
80101	Computer,Hardware,Micro (Pc)	4
80103	Computer,Hardware,Input/Output	5
80105	Laptops	3
80204	Storage Device, Disc/Tape	5
80302	Software - Mainframe	10-SQ
80303	Software - Mid-Range Systems	5-SQ
80304	PC Software	4
80305	Software Upgrade, mid-range systems	2
80306	Network Software	5
80401	Stimulator, Training	5
80501	Premise Cabling	7
80502	Routers	5-SQ
80503	Switches	5-SQ
80504	Servers	5-SQ

BC Hydro
TABLE 1A - Summary of Existing Components
Profile ID's for Assets Owned and Operated by BC Hydro

Profile ID	Description	Estimated Life
80508	Misc. Network Equipment	4
81001	Automobiles	8-L2.5
81101	Trucks < 1 Ton- 2 Wheel Drive	8-L2.5
81201	Trucks < 1 Ton- 4 Wheel Drive	8-L2.5
81301	Trucks > 1 Ton-2 Wheel Drive	13-R1.5
81302	Trucks > 1 Ton-4 Wheel Drive	13-R1.5
81401	Trucks >= 1 Ton 4 Wheel Drive	13
81501	Trucks >= 1 Ton 6 Wheel Drive	12
81601	Tractor - Highway	9-L2.5
81701	Aerial Device	13
81702	Line / Service / Van Body	15-R3
81703	Derricks / Diggers	15
81704	Ride-A-Rails	25
82501	Forklift / Pallet Jack	20-R3
82502	Snow Vehicle	20-R3
82503	Sweeper	15
82504	Loader / Backhoe	17-R1.5
82505	Trailer - Reel / Pole / Utility	20-R1.5
82506	Welder, Mobile, Self-Powered	15
82507	Compressor,Mobile,Self-Powered	15
82508	Chipper	15
82512	Regen Plan, Xformer Oil	15
82513	Manlift	15
82514	All Terrain Vehicle	8
82550	Tools and Work Equipment	15
82601	Test / Calibration Equipment	15-SQ
82603	Manufacturing/Test Equipment	15
83001	Boat	15
83002	Boat, Tugboat	20
85001	Office Furniture	15
85003	Signs/Plaques	30
88001	Lab Equipment, Hi-Pwr Lab	20
88002	Lab Equipment, Misc	15
88003	Lab Equipment, Hi-Pwr Lab	15
99401	Generation - Pre 1996 Contributions in Aid	20
99403	Distribution - Pre 1996 Contributions in Aid	45
99405	Substation - Pre 1996 Contributions in Aid	40
99601	Columbia River Treaty	52
99602	Columbia River Treaty - Contributions in Aid	52

BC Hydro
TABLE 1A - Summary of Existing Components
Profile ID's for Assets Owned and Operated by BC Hydro

Profile ID's for Assets Operated or Primarily Operated by BCTC

Profile ID	Description	Estimated Life
11602	Easement/right of way	N/A
11626	Land Rights,Finite Life, 20Yrs	20
11701	Clearing-Transmission	100
11901	Yard Surfacing	35
12001	Trail, Caterpillar	50
12301	Pad, Helicopter	25
12402	Landscaping	25
21102	Erosion Donut &/Or Bank	25
21103	Debris/Avalance Deflector	25
22006	Equipment Shelter	10
25101	Structure - Steel Support	65
25102	Structure, Support, Wood	30
25202	Pole Structures	50
25203	Towers	65
25301	Foundations	40
25401	Trenches and Ducts	50
25502	Ductbanks > 60Kv	50
42201	Resistor - Load Breaking	25
51002	Condenser - Synchronous, Static	40
52102	Transformer - Auto / Bulk System	45
52103	Transformer - Power > 100 Mva	40
52104	Transformer - Power < 100 Mva	45
52106	Transformer - Power - Composite Pool	45
52301	Reactor - Oil	25
52302	Reactor - Dry Type	40
52303	Reactor - Composite Pool	40
52401	Transformer - Oil / 69 Kv & Above	40
52402	Transformer - Gas / Sf6 / 69 Kv & Above	40
52403	Oil, < 69 Kv	35
52404	Transformer - Current, Encaps	45
52405	Transformer - Current, Composite Pool	50
52406	Comb Ct & Vt Transformer	40
52501	Transformer,Voltage,Capacitor	35
52502	Transformer,Voltage,Oil-Fill	40
52503	Transformer,Voltage,Gas-Fill	50
52504	Transformer,Voltage,Encaps.	45
52505	Transformer,Volt,Comp. Pool	40
53101	Capacitor - Shunt	30
53201	Capacitor - Series	35
53202	Metal Oxide Varister (Mov)	35
53301	Capacitor - Coupling	35
54102	Breakers - Gas (Sf6) 12/25 Kv	30
54103	Breakers - Bulk/Mon Oil/Air Blast	45
54104	Breakers - Gas (Sf6) 69 To 500 Kv	45
54105	Breakers - Composite Pool	35
54201	Use Individual Disconnect Caus	40

BC Hydro
TABLE 1A - Summary of Existing Components
Profile ID's for Assets Owned and Operated by BC Hydro

Profile ID	Description	Estimated Life
54203	Disconnect - 3 Phase - 12/25 Kv	35
54204	Disconnect - 3 Phase - 69-230 Kv	35
54205	Disconnect - 3 Phase - 500 Kv	35
54401	Switchgear - Metalclad	30
54501	Circuit Recloser	40
54601	Circuit Switcher	30
55101	Overhead Conductor > 60 kV	60
55103	Line Disconnect Switches	25
55302	Cable - Underground > 60 Kv	40
55303	Cable - Submarine > 60 Kv	45
55401	Buswork and Station Conductor	60
55501	Grounding Systems	40
56001	Insulators	55
57001	Surge Arrestor	30
58001	Converter	30
58002	Inverter	30
58101	Var Compensator - Static	40
58201	Resistor, Anode Damping	25
59101	Regulator - Feeder Circuit	30
59201	Charger System, Battery	20
59301	Storage Batteries, Bank	20
59601	Metering, Dcp, Trolleys	35
61001	Fencing	25
65001	Panels/Cubicles, P&C	20
65101	Fault Locating& Reporting	20
67001	Liner, Pvc, Spill Containment	35
67005	Oil Spill Containment	35
67006	Containment System, Oil Spill	35
68001	Carrier System, Power Line	15
68101	Antennae & Waveguide,Microwave	20
68201	Control Center - Master Equipment	12
68202	Terminal Unit - Remote	20
68203	Integrated Control/Data(Icda)	5
68302	Radio - Microwave - Digital	35
68303	Microwave	20
68401	Multiplex Device, Analog	5
68402	Multiplex Device - Digital	20
68503	Radio Equipment, Protection	25
68601	Protection Tone System	20
68602	Digital Teleprotection System	20
68701	Wave Trap / Line Trap	20
68801	Fibre Optic System	20
70001	Cable, Entrance Protection	20
70102	Accelerometers	20
70103	Seismic Monitoring Equipment	20
73001	Cooling System - Air	25
75101	Drier, Air	25
75103	Piping, Stainless Steel	40
75201	Tanks, Steel, Air/Fuel	30
75202	Tank,Fibrglas,Dbl Bottom,Fuel	30
75204	Tanks - Concrete	30
82510	Railcars	35
89501	Animal Preventative Equipment	20
99404	Transmission - Contributions in Aid	40

BC Hydro
TABLE 1A - Summary of Existing Components
Profile ID's for Assets Owned and Operated by BC Hydro

Burrard Thermal Generation Plant

Profile ID	Description	Estimated Life
30101	Boilers, Casing	30
30102	Boiler. Insulation	30
30103	Roof, Boiler	30
30201	Waterwall, Boiler	30
30203	Superheater, High Temp	30
30204	Superheater - Low Temp	30
30205	Reheater, Boiler	30
30301	Header - Drum	40
30501	Piping - High Pressure	40
30601	Fan - Forced Draft	30
30602	Breaching - Flue System	30
30603	Stack, Flue Gases	30
30604	Preheater, Air	30
30605	Burner - Fuel	15
30606	Instrumentation - Boiler	30
30608	Control System, Feedwater	15
30609	Seals - Crown	30
30610	Control System, Fuel	15
30611	Desuperheater System	15
30612	Refractory, Boiler	20
30613	Boiler, Package	30
30801	Transfer System, Ammonia	20
30802	Water Deluge System, Ammonia	30
30803	Vapouriser, Ammonia	20
30804	Compressor, Vapour, Ammonia	15
30805	Piping System, Ammonia	30
30901	Monitoring Equipment - Continuous Emissions	10
30902	Reporting System, Cem	10
30903	Delivery System - Ammonia - Scr	30
30904	Catalyst - Scr	10
31001	Water Intake / Discharge Structure	50
31002	Protection, Cathodic	20
31003	Gates, Inlet/Outlet	30
31004	Screens - Intake	20
31005	Conduit, Intake/Discharge	50
33001	Heat Exchanger, Shell & Tube	30
33002	Pump & Motor	30
33004	Condenser, Boiler	30
34002	Casing Cylinder	30
34004	Turbine - Composite Pool	30
34005	Coils - Stator	30
34006	Rotor / Generator - Thermal	30
34007	Generator - Composite Pool - Thermal	30
34008	Supervisory System, Turbine	20
34009	Cooling System - Hydrogen	30
34015	Turbine Blades Sets	15

FORTISALBERTA, INC.

SCHEDULE 1. ESTIMATED SURVIVOR CURVES, NET SALVAGE PERCENTS, ORIGINAL COST AND ANNUAL ACCRUALS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2010

LIFE ANALYSIS

Account	Description	Estimated Survivor Curve	Estimated Net Salvage	Surviving Original Cost at 12/31/2010	Calculated Annual Accrual		Annual Provision For True-Up	Total Depreciation	
					Amount	Rate (%)		Expense	Rate (%)
	(1)	(2)	(3)	(4)	(5)	(6)=(5)/(4)	(7)	(8)=(5)+(7)	(9)=(8)/(4)
1050	SURFACE AND MINERAL RIGHTS	36-L3	0	13,086,005	394,963.30	3.02	(18,133)	376,830	2.88
1350	BUILDINGS AND/OR MAJOR IMPROVEMENTS - DIST.	25-L1	5	87,731,944	3,844,146.58	4.38	-	3,844,147	4.38
1360	BUILDINGS - GENERAL	40-R1.5	10	13,691,435	366,691.13	2.68	11,445	378,136	2.76
1650	DISTRIBUTION - POLES, TOWERS, FIXTURES	45-R1.5	0	840,236,529	22,138,771.26	2.63	(1,079,058)	21,059,713	2.51
1660	DISTRIBUTION - OH CONDUCTORS	45-R1	0	579,735,568	16,298,181.08	2.81	(1,058,527)	15,239,654	2.63
1670	DISTRIBUTION - UG CONDUCTORS	58-R2	0	552,712,739	11,886,556.33	2.15	(1,418,789)	10,467,767	1.89
1675	DISTRIBUTION - TRANSFORMERS / REGULATORS / OCR	27-R0.5	0	609,979,356	25,908,710.93	4.25	-	25,908,711	4.25
1680	DISTRIBUTION - SCADA	10-R2	0	1,135,239	133,704.24	11.78	12,980	146,684	12.92
1685	DISTRIBUTION - STREET LIGHTING	20-R1	0	41,289,296	2,243,846.06	5.43	149,051	2,392,897	5.80
1690	DISTRIBUTION - STREET LIGHT POLES	45-R1.5	0	112,816,095	3,000,159.60	2.66	76,694	3,076,854	2.73
1825	AMR - DIGITAL METERS	15-R0.5	0	79,650,717	8,755,697.28	10.99	489,324	9,245,021	11.61
1835	AMR - SUBSTATION EQUIPMENT	15-R1.5	0	32,156,444	2,927,028.24	9.10	161,366	3,088,394	9.60
1845	AMR - SKID INFRASTRUCTURE	25-R1.5	0	2,162,342	123,650.69	5.72	2,616	126,267	5.84
2050	OFFICE FURNITURE AND EQUIPMENT	15-SQ	0	1,939,307	129,351.76	6.67	-	129,352	6.67
2055	DISTRIBUTION - OFFICE FURNITURE	15-SQ	0	9,397,751	626,829.99	6.67	32,963	659,793	7.02
2100	FLEET VEHICLES (<1 TON)	5-L1	15	18,687,539	3,134,896.30	16.78	807,048	3,941,944	21.09
2105	CORPORATE VEHICLES	3-SQ	50	439,727	54,664.55	12.43	(19,799)	34,866	7.93
2110	VEHICLES OVER 1 TON & OTHER WORK EQUIPMENT	14-S4	15	50,869,533	3,175,835.52	6.24	268,475	3,444,311	6.77
2200	GENERAL TOOLS AND INSTRUMENTS	10-SQ	0	15,521,919	1,552,191.89	10.00	-	1,552,192	10.00
2251	COMPUTER - PC'S AND LAPTOPS	3-SQ	0	5,669,174	1,889,535.83	33.33	557,837	2,447,373	43.17
2252	COMPUTER - SERVERS AND OTHER	5-R4	0	18,333,320	3,600,035.04	19.64	585,399	4,185,434	22.83
2260	MOBILE COMMUNICATION EQUIPMENT	7-SQ	0	480,571	68,673.60	14.29	(17,853)	50,821	10.58
2301	SAP	10-R4	0	50,361,481	5,158,884.58	10.24	(456,119)	4,702,766	9.34
2302	MAJOR APPLICATIONS	5-R4	0	9,997,017	1,991,367.78	19.92	2,284,251	4,275,619	42.77
2303	COMPUTER SOFTWARE - OTHER	5-SQ	0	18,132,188	3,626,437.57	20.00	1,163,615	4,790,053	26.42
2310	LOAD SETTLEMENT SOFTWARE	5-R4	0	3,142,339	564,561.94	17.97	79,536	644,098	20.50
	TOTAL DEPRECIABLE PLANT			3,169,355,574	123,595,373		2,614,322	126,209,695	
	OTHER								
	DIGITAL METERS IN STORES			5,603,197	615,791	10.99	51,692	667,483	11.91
	CUSTOMER CONTRIBUTIONS			(614,894,056)	(20,134,307)	3.27	3,339,915	(16,794,392)	2.73
	CUSTOMER CONTRIBUTIONS - SPP			(1,653,323)	(54,137)	3.27	17,642	(36,495)	2.21
	CONTRIBUTIONS: CUSTOMER REQUESTED CHANGES			(68,409,991)	(2,240,041)	3.27	(319,183)	(2,559,224)	3.74
	AESO CONTRIBUTION			101,750,994	3,331,770	3.27	598,601	3,930,371	3.86
	TOTAL OTHER			(577,603,178)	(18,480,923)		3,688,667	(14,792,256)	
	PLANT NOT STUDIED								
	DISTRIBUTION - ANALOG METERS			58,918,918					
	LAND			11,855,819					
	DISTRIBUTION - MAJOR INSPECTIONS			470,072					
	LEASEHOLD IMPROVEMENTS			3,243,064					
	TOTAL PLANT NOT STUDIED			74,487,873					
	TOTAL PLANT IN SERVICE			2,666,240,270	105,114,450		6,302,989	111,417,439	

FORTISBC, INC.

SCHEDULE 2. ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO UTILITY PLANT AS OF DECEMBER 31, 2009
DEPRECIATION RELATED TO RECOVERY OF ORIGINAL COST OF INVESTMENT

	DEPRECIABLE WORK	SURVIVOR CURVE	NET SALVAGE (%)	ORIGINAL COST AT DECEMBER 31, 2009	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	GENERATION PLANT								
330.10	LAND RIGHTS	75-R4	0	961,358	(709,439)	1,670,797	36,531	3.80	45.7
331.00	STRUCTURES AND IMPROVEMENTS	60-L3	0	12,015,310	4,714,257	7,301,053	154,738	1.29	47.2
332.00	RESERVOIRS, DAMS, AND WATERWAYS	70-R4	0	24,443,427	3,290,720	21,152,707	492,446	2.01	42.9
333.00	WATER WHEELS, TURBINES, AND GENERATORS	75-R3	0	61,382,405	4,165,975	57,216,430	1,197,917	1.95	47.8
334.00	ACCESSORY ELECTRICAL EQUIPMENT	50-R3	0	27,493,467	7,725,117	19,768,350	648,832	2.36	30.4
335.00	OTHER POWER PLANT EQUIPMENT	45-R4	0	40,893,990	8,029,184	32,864,806	947,694	2.32	34.7
336.00	ROADS, RAILROADS AND BRIDGES	75-S4	0	1,287,435	233,134	1,054,301	19,214	1.49	54.9
	TOTAL GENERATION PLANT			**168,477,392**	**27,448,948**	**141,028,444**	**3,497,372**	**2.08**	
	TRANSMISSION PLANT								
350.10	LAND RIGHTS	75-R3	0	5,798,520	1,103,235	4,695,285	85,106	1.47	55.2
353.00	SUBSTATION EQUIPMENT	50-S4	0	138,236,257	29,775,810	108,460,447	4,758,609	3.44	22.8
355.00	POLES, TOWERS AND FIXTURES	50-R3	0	72,712,210	17,470,103	55,242,107	1,922,254	2.64	28.8
356.00	CONDUCTORS AND DEVICES	60-R3	0	70,447,452	14,363,421	56,084,031	1,442,900	2.05	38.9
359.00	ROADS AND TRAILS	40-R0.5	0	1,121,930	55,044	1,066,886	30,050	2.68	35.5
	TOTAL TRANSMISSION PLANT			**288,316,368**	**62,767,613**	**225,548,755**	**8,238,919**	**2.86**	
	DISTRIBUTION PLANT								
360.10	LAND RIGHTS	75-R3	0	8,477,101	472,271	8,004,830	225,551	2.66	35.5
362.00	SUBSTATION EQUIPMENT	55-S3	0	181,230,662	32,248,509	148,982,153	3,986,601	2.20	37.4
364.00	POLES, TOWERS AND FIXTURES	50-R3	0	126,978,444	34,246,501	92,731,943	2,706,149	2.13	34.2
365.00	CONDUCTORS AND DEVICES	45-R3	0	208,986,680	49,392,215	159,594,465	5,366,420	2.57	29.7
368.00	LINE TRANSFORMERS	45-R4	0	98,456,668	15,995,063	82,461,605	3,360,316	3.41	24.6
369.00	SERVICES	75-R4	0	7,292,398	6,475,852	816,546	11,420	0.16	71.5
370.00	METERS	15-R1	0	13,276,592	6,809,246	6,467,346	1,762,556	13.28	3.7
371.00	INSTALLATIONS ON CUSTOMERS PREMISES	20-R1	0	937,832	937,832	-	-	-	0.0
373.00	STREET LIGHTING AND SIGNAL SYSTEMS	40-R4	0	10,274,609	1,482,786	8,791,823	2,361,225	22.98	3.7
	TOTAL DISTRIBUTION PLANT			**655,910,986**	**148,060,275**	**507,850,711**	**19,780,238**	**3.02**	
	GENERAL PLANT								
390.00	STRUCTURES - FRAME AND IRON	40-R3	0	337,364	266,696	70,668	2,384	0.71	29.6
390.10	STRUCTURES- MASONRY	35-R3	0	8,931,826	1,729,033	7,202,793	557,504	6.24	12.9
390.20	OPERATIONS BUILDINGS	35-R3	0	12,750,128	2,405,273	10,344,855	767,587	6.02	13.5
391.00	OFFICE FURNITURE AND EQUIPMENT	15-SQ	0	5,475,178	3,811,035	1,664,143	199,244	3.64	8.4
391.10	COMPUTER EQUIPMENT & SOFTWARE	10-SQ	0	31,957,542	20,400,688	11,556,854	1,599,848	5.01	7.2
391.20	PC COMPUTER EQUIPMENT & SOFTWARE	5-SQ	0	24,929,022	14,475,255	10,453,767	2,613,442	10.48	4.0
392.10	LIGHT DUTY VEHICLES	8-L3	20	6,766,552	186,391	5,226,851	1,266,432	18.72	4.1
392.20	HEAVY DUTY VEHICLES	20-L3	20	10,785,689	2,413,034	6,215,518	415,905	3.86	14.9
394.00	TOOLS AND WORK EQUIPMENT	15-SQ	0	10,869,029	6,546,629	4,322,400	438,361	4.03	9.9
397.00	COMMUNICATIONS STRUCTURES AND EQUIPMENT	15-SQ	0	22,698,403	7,165,405	15,532,998	1,827,007	8.05	8.5
	TOTAL GENERAL PLANT.			**135,500,733**	**59,399,439**	**72,590,846**	**9,687,714**	**7.15**	
	TOTAL DEPRECIABLE PLANT			**1,248,205,480**	**297,676,275**	**947,018,757**	**41,204,242**	**3.30**	
	PLANT NOT STUDIED								
114.0	UTILITY PLANT ACQUISITION ADJUSTMENT			11,912,000	4,839,225	-	-		
350.0	LAND RIGHTS			7,204,996	-	-	-		
360.0	LAND RIGHTS			2,456,724	-	-	-		
389.0	LAND			11,297,255	34,055	-	-		
390.9	LEASEHOLD IMPROVEMENTS			4,401,334	2,054,075	-	-		
	TOTAL NON - DEPRECIABLE PLANT			**37,272,309**	**6,927,355**	-	-		
	TOTAL PLANT			**1,285,477,789**	**304,603,630**	**947,018,757**	**41,235,054**		

*minimum life of 4 years.

NEWFOUNDLAND AND LABRADOR HYDRO

SCHEDULE 1. ESTIMATED SURVIVOR CURVES, ORIGINAL COST AND ANNUAL ACCRUALS
RELATED TO ESTIMATED ORIGINAL COST AT DECEMBER 31, 2009
EXCLUDES HOLYROOD ASSETS NOT REQUIRED FOR SYNCHRONOUS CONDENSER OPERATIONS
AVERAGE SERVICE LIFE USED

	DEPRECIABLE WORK	SURVIVOR CURVE	ORIGINAL COST AT DECEMBER 31, 2009	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
A01	AIRCRAFT LANDING STRIP	22-S6	394,805.08	217,451	177,354	29,659	7.51%	6.0
A04	AUXILIARY POWER SYSTEMS	30-R4	3,283,352.56	1,647,378	1,635,975	140,058	4.27%	11.7
B01	BATTERY & POWER SYSTEMS	15-S3	8,289,725.71	3,637,112	4,652,614	551,949	6.66%	8.4
B02	BOILER SYSTEM	35-R3	1,946,158.89	395,063	1,551,096	47,773	2.45%	32.5
B03	BOOMS - TIMBERS	40-R1	263,995.47	236,552	27,443	1,211	0.46%	22.7
B04	BRIDGES	60-R4	4,257,163.40	3,049,973	1,207,190	26,669	0.63%	45.3
B05	BUILDINGS - OTHER	50-R0.5	48,812,722.58	23,386,172	25,426,551	607,725	1.25%	41.8
B06	BUILDINGS - METAL	55-R3	19,943,772.82	14,357,796	5,585,977	139,092	0.70%	40.2
B07	BUS DUCT GENERATOR	35-R3	825,804.04	425,560	400,244	19,467	2.36%	20.6
B08	BUSWORK & HARDWARE	40-R3	5,539,614.59	2,748,318	2,791,297	143,629	2.59%	19.4
C01	CABLES - TELECONTROL	40-R2.5	1,605,996.01	1,172,691	433,305	12,865	0.80%	33.7
C02	CABLE - SUBMARINE	45-R4	8,901,116.47	5,618,356	3,282,760	118,060	1.33%	27.8
C03	CABLES - UNDER GROUND	60-S4	1,852,851.63	1,202,958	649,894	17,988	0.97%	36.1
C04	CABLES - ABOVE GROUND	50-R3	9,336,561.23	5,199,675	4,136,886	144,987	1.55%	28.5
C06	CAPICTORS	35-R4	1,004,935.12	140,385	864,550	55,809	5.55%	15.5
C08	CHLORINATION SYSTEMS	40-R4			-			
C09	CIRCUIT BREAKERS	55-R3	16,714,614.21	6,625,080	10,089,534	292,052	1.75%	34.5
C10	COMPRESSED AIR SYSTEMS	40-R3	4,662,228.89	2,395,576	2,266,653	75,241	1.61%	30.1
C11	COMPUTERS	5-SQ	5,619,782.72	4,065,444	1,554,339	518,113	9.22%	3.0 *
C13	CONDUCTOR	60-R3	62,857,533.60	16,902,895	45,954,639	1,260,421	2.01%	36.5
C14	CONDUCTOR - DISTRIBUTION	55-R3	21,401,471.20	9,384,068	12,017,403	275,421	1.29%	43.6
C15	CONTROL, METER / RELAYING	30-R1	18,718,502.07	8,317,645	10,400,857	541,267	2.89%	19.2
C16	COOLING SYSTEMS	40-R1.5	3,794,719.13	2,097,408	1,697,311	47,726	1.26%	35.6
C17	COUNTERPOISE	50-R3	3,558,954.86	991,815	2,567,140	84,482	2.37%	30.4
C18	CRANES	70-R3	6,369,327.68	462,789	5,906,539	123,303	1.94%	47.9
D01	DAMS & DYKES	100-R4	351,201,750.94	1,781,039	349,420,712	4,794,055	1.37%	72.9
D02	DIESEL SYSTEMS & ENGINES	25-S0.5	21,346,252.47	11,394,298	9,951,954	516,378	2.42%	19.3
D03	DISCONNECT SWITCHES	45-S2.5	9,114,371.51	4,056,214	5,058,158	196,234	2.15%	25.8
D04	DYKES AND LINERS	42-L1	1,887,138.00	1,592,485	294,653	8,961	0.47%	32.9
E01	ELEVATORS	40-S5	89,800.00	89,800	-		0.00%	
E02	EMS EQUIPMENT	25-R2.5	13,446,886.26	13,184,644	262,242	12,810	0.10%	20.5
E03	ENVIRONMENTAL EQUIPMENT	30-S4	10,395.75	2,630	7,766	272	2.62%	28.6
F01	FALL ARREST EQUIPMENT	10-L2	1,318,153.90	103,513	1,214,641	153,076	11.61%	7.9
F02	FENCING	47-R3	4,825,159.64	2,883,646	1,941,514	51,216	1.06%	37.9
F03	FIRE FIGHTING EQUIPMENT	45-R4	9,222,528.23	4,799,183	4,423,345	117,471	1.27%	37.7
F04	FOOTINGS & FOUNDATIONS	50-R4	16,144,467.22	6,483,604	9,660,863	359,895	2.23%	26.8
F05	FREQ CONVERSION	40-S4	869,211.95	36,565	832,647	21,233	2.44%	39.2
F06	FUEL SYSTEMS	50-R1.5	14,784,748.08	7,307,166	7,477,582	163,431	1.11%	45.8
G01	GAS TURBINE SYSTEMS	35-R4	30,993,022.69	25,552,246	5,440,777	271,761	0.88%	20.0
G02	GATES	80-R4	15,312,218.70	1,743,278	13,568,941	262,474	1.71%	51.7
G03	GENERATORS	60-S4	64,312,110.88	24,318,003	39,994,108	1,110,298	1.73%	36.0
G04	GENERATOR - WINDINGS	40-S3	6,766,230.94	6,392,535	373,696	21,714	0.32%	17.2
G05	GLYCOL SYSTEMS	40-S3	620,703.54	495,234	125,470	5,537	0.89%	22.7
G06	GOVENORS	45-S4	7,685,239.39	394,699	7,290,540	293,835	3.82%	24.8
G07	GROUND WIRE SYSTEM	55-R4	7,302,893.45	2,167,951	5,134,942	140,028	1.92%	36.7
H01	HRDWIRED SUPRVSRY EQUIP	17-L3			-			
I01	INFORMATION DELIVERY SYS - ECC	20-S4			-			
I02	INSTRUMENTATION	26-L0.5	4,018,333.05	1,212,524	2,805,809	124,014	3.09%	22.6
I03	INSULATORS	30-L3	36,376,195.89	10,491,724	25,884,472	1,383,214	3.80%	18.7
I04	INTAKE STRUCTURES	100-R4	18,844,444.76	100,300	18,744,145	254,192	1.35%	73.7
I05	INVERTERS	25-S3	466,597.96	312,787	153,811	9,496	2.04%	16.2
L03	LAND IMPROVMENTS	50-R3	12,638,775.53	7,147,132	5,491,644	184,973	1.46%	29.7
L04	LIGHTING SYSTEMS	45-R4	550,249.54	390,331	159,919	9,599	1.74%	16.7
L05	LIGHTNING ARRESTORS	58-R3	5,619,879.81	1,764,959	3,854,921	78,524	1.40%	49.1
L06	LINE COUPLING EQUIPMENT	23-R5	12,725.56	12,726	(0)		0.00%	
M01	MAIN BREAKERS	42-R0.5	551,508.09	210,996	340,512	9,197	1.67%	37.0
M03	METALCLAD SWITCHGEAR CUB/EQU 4kv/600	30-R4	1,849,870.49	1,442,814	407,056	48,728	2.63%	8.4
M04	METER TEST SWITCHES	35-R5	48,910.55	31,786	17,125	1,016	2.08%	16.9
M05	METERING TANKS	37-R3	208,167.19	108,522	99,645	5,773	2.77%	17.3
M06	METERS - DIGITAL	20-L3	3,430,944.36	745,450	2,685,494	194,142	5.66%	13.8
M07	METERS - ANALOGUE	25-L3	488,014.47	370,459	117,555	14,557	2.98%	8.1
M08	METERS - OTHER	22-L3	194,391.51	72,936	121,456	10,353	5.33%	11.7
M10	MISC. UNITS OF PROP	20-R1	2,035,856.23	1,205,671	830,185	115,490	5.67%	7.2
M11	MOBILE - A.T.V.'S & SNOWMOBILES	7-SQ	1,369,874.43	550,216	819,658	161,322	11.78%	5.1
M12	MOBILE - AIR COMPRESSOR,ATTACHMENT &BOAT	20-R2	410,663.64	325,669	84,995	4,495	1.09%	18.9
M13	MOBILE - ARGO'S	7-SQ	30,211.03	28,589	1,622	541	1.79%	3.0 *
M14	MOBILE - FLEX/FORK/LOAD/GRADE/MUSK/TRAILER	20-R2	8,248,424.67	5,220,195	3,028,230	171,332	2.08%	17.7
M16	MULTIPLEX EQUIPMENT	18-R2.5	2,889,207.03	2,096,283	792,924	65,964	2.28%	12.0
O01	OFFICE EQUIPMENT	20-SQ	1,195,347.67	877,289	318,059	17,556	1.47%	18.1
O02	OFFICE FURNITURE	20-SQ	4,269,330.12	3,839,669	429,661	25,252	0.59%	17.0
P01	P.C.B. STORAGE CONTAINER	30-R4	42,479.84	38,586	3,894	317	0.75%	12.3
P02	PABX - PRIV AUTO BRANCH EXCH	20-R4	819,535.49	427,128	392,407	23,938	2.92%	16.4
P03	PENSTOCK	70-R4	56,215,065.27	8,625,533	47,589,532	1,123,136	2.00%	42.4
P04	POLE CRIBS & POLE HARDWARE	50-L2	65,911,264.63	22,355,247	43,556,018	1,028,846	1.56%	42.3
P05	POLE STRUCTURES - WOOD	53-R4	104,505,267.12	25,429,257	79,076,010	2,394,419	2.29%	33.0
P06	POLES - CONCRETE	25-R4	215,304.78	160,922	54,383	9,266	4.30%	5.9
P07	POLES - WOOD	37-R3	40,210,866.37	16,899,802	23,311,064	800,789	1.99%	29.1

NEWFOUNDLAND AND LABRADOR HYDRO

SCHEDULE 1. ESTIMATED SURVIVOR CURVES, ORIGINAL COST AND ANNUAL ACCRUALS
RELATED TO ESTIMATED ORIGINAL COST AT DECEMBER 31, 2009
EXCLUDES HOLYROOD ASSETS NOT REQUIRED FOR SYNCHRONOUS CONDENSER OPERATIONS
AVERAGE SERVICE LIFE USED

	DEPRECIABLE WORK	SURVIVOR CURVE	ORIGINAL COST AT DECEMBER 31, 2009	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
P08	POWER LINE CARRIER	20-R4	5,006,762.55	3,748,600	1,258,163	81,860	1.63%	15.4
P09	POWER SYSTEMS	18-R3	590,182.62	116,245	473,938	41,511	7.03%	11.4
P10	POWERHOUSE	75-R3	93,181,235.98	13,007,098	80,174,138	1,552,941	1.67%	51.6
P11	PRINTERS	5-SQ	1,010,719.71	572,117	438,603	141,116	13.96%	3.1
P12	PROTECTIVE CONTROL & RELAY PANELS	30-R3	4,458,227.98	909,807	3,548,421	186,149	4.18%	19.1
R01	RADIO TOWERS (WOOD OR STEEL)	35-R3	9,331,364.82	6,073,961	3,257,404	112,622	1.21%	28.9
R02	RADIOS - FIXED MICROWAVE EQUIPMENT	22-R4	5,431,981.92	3,846,942	1,585,040	105,328	1.94%	15.0
R03	RADIOS - FIXED UHF EQUIPMENT	15-L1.5	114,223.78	18,190	96,034	6,998	6.13%	13.7
R04	RADIOS - FIXED VHF EQUIPMENT	19-R3	330,529.66	275,437	55,093	4,296	1.30%	12.8
R05	RADIOS - MOBILE VHF BASE STATION	15-R3	4,027,815.31	971,834	3,055,981	245,822	6.10%	12.4
R06	RAMPS - YARD STORAGE	25-R3	1,236,643.69	525,696	710,948	34,391	2.78%	20.7
R07	REACTORS & RESISTORS	40-S4	860,433.73	69,734	790,700	30,667	3.56%	25.8
R08	RECLOSERS	40-R4	3,465,827.78	1,683,894	1,781,934	65,403	1.89%	27.2
R09	REGULATORS	35-R3	3,777,179.98	1,618,625	2,158,555	88,451	2.34%	24.4
R10	RESERVOIR POWER	30-R3			-			
R11	REVENUE METERING	35-R3	761,706.46	202,490	559,216	33,616	4.41%	16.6
R12	RIGHT - OF - WAYS	55-R4	18,020,542.37	5,989,582	12,030,960	411,599	2.28%	29.2
R13	ROADS	50-R4	80,846,786.54	3,979,048	76,867,739	2,936,650	3.63%	26.2
R14	ROUTERS & LAN	5-SQ	6,097,245.86	4,797,798	1,299,448	433,149	7.10%	3.0 *
R15	RUNNER	33-R5	11,669,901.86	3,427,671	8,242,231	577,150	4.95%	14.3
S01	SCADA EQUIPMENT	20-R3	3,427,679.44	1,934,879	1,492,800	93,488	2.73%	16.0
S02	SECTIONALIZERS	25-R3	152,708.72	93,118	59,591	6,174	4.04%	9.7
S03	SERVERS	5-SQ	5,081,124.97	3,626,053	1,455,072	485,024	9.55%	3.0 *
S04	SEWAGE DISPOSAL SYSTEM	45-R2.5	2,745,341.78	1,708,195	1,037,147	28,232	1.03%	36.7
S05	SOFTWARE	7-SQ	24,077,181.78	19,989,114	4,088,068	897,882	3.73%	4.6
S06	SPILLWAY STRUCTURES	100-R4	26,949,270.20	252,588	26,696,682	362,935	1.35%	73.6
S07	STACKS	40-R4	2,126,667.19	1,368,383	758,284	22,965	1.08%	33.0
S08	STATIC EXCITATION SYSTEM	32-R4	8,295,339.31	4,208,323	4,087,016	231,836	2.79%	17.6
S09	STATIC EXCITATION - XFORMERS	32-R4	873,229.34	727,374	145,855	20,302	2.32%	7.2
S10	STATION SERVICE	40-R4	3,399,370.83	800,120	2,599,251	147,423	4.34%	17.6
S11	STOP LOGS	65-R4	2,780,641.69	275,711	2,504,931	60,078	2.16%	41.7
S12	STORAGE PALLETS & RACKINGS	30-R3	21,648.13	21,648	0		0.00%	
S13	STORM & YARD DRAINAGE	45-R4	1,194,341.65	982,815	211,527	7,776	0.65%	27.2
S14	STREET LIGHTS	20-R2	2,546,773.85	637,293	1,909,481	143,203	5.62%	13.3
S15	STRUCTURAL SUPPORTS (WOOD OR STEEL)	45-R4	8,609,349.55	3,876,232	4,733,118	211,680	2.46%	22.4
S16	STUDIES	5-R0.5	3,358,184.45	1,444,249	1,913,935	511,961	15.25%	3.7
S17	SUMP SYSTEMS	35-R4	238,638.74	84,300	154,339	6,277	2.63%	24.6
S18	SURGE SYSTEMS	45-R3	3,348,520.61	1,702,117	1,646,404	105,503	3.15%	15.6
S19	STATION SWITCHING	45-L1.5	10,667,170.66	3,862,529	6,804,642	196,609	1.84%	34.6
S20	SWITCHING SYSTEMS - L.V.	60-R5	1,805,689.30	116,296	1,689,393	50,232	2.78%	33.6
T01	TELECONTROL SYSTEM	27-L1	10,919,784.86	8,230,476	2,689,309	117,403	1.08%	22.9
T02	TEST EQUIPMENT	20-SQ	2,128,465.42	1,876,474	251,991	13,671	0.64%	18.4
T03	TOOLS & EQUIPMENT	20-SQ	11,281,655.65	7,613,134	3,668,522	202,266	1.79%	18.1
T04	TOWERS	65-R3	71,559,609.79	13,980,497	57,579,113	1,298,875	1.82%	44.3
T05	TRANSFORMERS	55-R3	66,582,133.35	25,739,897	40,842,236	1,149,555	1.73%	35.5
T06	TRANSFORMERS - PADMOUNT	40-R3	2,379,222.82	807,836	1,571,387	50,050	2.10%	31.4
T07	TRANSFORMERS - POLE MOUNTED	30-R2	16,385,241.31	4,804,173	11,581,068	499,684	3.05%	23.2
T09	TURBINES	50-R3	42,852,398.82	3,835,012	39,017,387	1,385,887	3.23%	28.2
V01	VACUUM CLEANING SYSTEM	60-R4	72,451.00	65,210	7,241	232	0.32%	31.2
V02	VALVES - PENSTOCK	65-R3	6,882,405.29	1,183,261	5,699,144	122,523	1.78%	46.5
V03	VEHICLES - 1 TON	8-L4			-			
V04	VEHICLES - 3/4 TON AND UNDER	7-L3	3,157,849.72	1,627,287	1,530,563	327,819	10.38%	4.7
V05	VEHICLES - BOOMS/BODIES/CRANES/CAB &CHASSIS	15-L1.5	10,935,865.73	7,626,020	3,309,846	245,782	2.25%	13.5
V06	VEHICLES - CARS, STATION WAGONS & VAN	6-L3	2,088,514.89	1,153,743	934,772	238,370	11.41%	3.9
V07	VEHICLES - DUMP TRUCKS	20-L3	20,135.00	18,415	1,720	104	0.52%	16.5
W01	WATER REGULATING STRUCTURES	55-S4	21,392,991.48	2,437,259	18,955,732	538,286	2.52%	35.2
W02	WATER SYSTEMS	30-L4	2,833,440.10	1,121,179	1,712,261	107,888	3.81%	15.9
W03	WATER SYSTEMS - FEED	45-L2	4,197,894.00	3,857,403	340,491	15,700	0.37%	21.7
W04	WATER TREATMENT	34-L4	2,793,278.18	2,101,734	691,544	43,702	1.56%	15.8
	TOTAL DEPRECIABLE PLANT		**1,851,258,222.78**	**529,577,511.00**	**1,321,680,711.78**	**39,083,183.00**		

* Three year minimum remaining life used

ONTARIO POWER GENERATION

SCHEDULE 1A - SUMMARY OF THE CURRENT AVERAGE SERVICE LIFE ESTIMATES AND
GANNETT FLEMING RECOMMENDED AVERAGE SERVICE LIFE ESTIMATES
PREVIOUSLY AND NEWLY REGULATED HYDROELECTRIC ASSETS AS AT DECEMBER 31, 2012

ASSET CLASS #	DESCRIPTION		NBV	% AGE	CURRENT	RECOMMENDED
10200000	HYDROELECTRIC - SUBSTRUCTURES AND SUPERSTRUCTURES	$	1,227,972,792	19.79%	100	100
10101000	HYDROELECTRIC - EXCAVATION, DREDGING, RIPRAPPING AND GROUTING	$	1,380,649,053	22.25%	100	100
10312000	HYDROELECTRIC - DAMS - CONCRETE	$	991,676,359	15.98%	100	100
10318000	HYDROELECTRIC - GATES, STOPLOGS AND OPERATING MECHANISMS	$	361,275,033	5.82%	50	55
10306000	HYDROELECTRIC - SURGETANK, PIPELINE, CONDUIT, PENTSTOCK	$	292,982,384	4.72%	75	75
10400000	HYDROELECTRIC - TURBINES AND GOVERNORS	$	213,248,856	3.44%	70	70
10501000	HYDROELECTRIC - MAIN ROTATIONAL ELECTRICAL EQUIPMENT - LESS WINDINGS	$	221,787,828	3.57%	75	75
10301000	HYDROELECTRIC - LINING OF TUNNELS AND PERMANENT SHAFTS	$	219,912,108	3.54%	75	75
10510000	HYDROELECTRIC - MAIN POWER AND STATION SERVICE - TRANSMISSION	$	175,590,706	2.83%	50	50
10500000	HYDROELECTRIC - MAIN ROTATIONAL ELECTRICAL EQUIPMENT - WINDINGS	$	114,912,729	1.85%	40	40
10311000	HYDROELECTRIC - DAMS - EARTH AND ROCKFILL	$	106,329,529	1.71%	100	100
10405000	HYDROELECTRIC - TURBINE RUNNERS	$	96,535,236	1.56%	40	40
10210000	HYDROELECTRIC - SERVICE AND EQUIPMENT BUILDINGS	$	101,137,556	1.63%	55	55
10502000	HYDROELECTRIC - BUS, SWITCHING AND POWER CABLE	$	85,327,386	1.37%	45	45
10300000	HYDROELECTRIC - CANAL, FOREBAY, RETAINING WALL LINING	$	83,670,918	1.35%	75	75
10504000	HYDROELECTRIC - CONTROL BOARDS AND SWITCHBOARDS	$	77,122,794	1.24%	25	25
10700000	HYDROELECTRIC - AUXILIARY SYSTEMS	$	72,291,792	1.16%	30	30
10302000	HYDROELECTRIC - SPILLWAYS, SLUICES, FLUMES	$	72,513,556	1.17%	75	75
10100000	HYDROELECTRIC - LAND	$	37,317,826	0.60%	100	100
10709000	HYDROELECTRIC - OWNED BRIDGES, RAILWAY TRACK, WHARVES	$	54,666,182	0.88%	65	65
10505000	HYDROELECTRIC - STATION SERVICE ELECTRICAL EQUIPMENT	$	44,045,969	0.71%	50	50
10601000	HYDROELECTRIC - MECHANICAL EQUIPMENT - CRANES AND FOLLOWERS	$	45,064,408	0.73%	55	55
10205000	HYDROELECTRIC - OUTDOOR STRUCTURES	$	20,878,634	0.34%	75	75
10710000	HYDROELECTRIC - FIRE PROTECTION SYSTEMS	$	27,019,773	0.44%	20	20
10503000	HYDROELECTRIC - HIGH VOLTAGE SWITCHING	$	16,335,367	0.26%	40	40
10503100	HYDROELECTRIC - REVENUE METERING - HIGH VOLTAGE SWITCHING, CONTROL BOARDS AND SWITCHBC	$	13,162,790	0.21%	30	30
10311100	HYDROELECTRIC - DAMS - TIMBER CRIB	$	8,624,328	0.14%	60	60
16210000	ADMINISTRATION AND SERVICE BUILDINGS - PERMANENT BLDGS. ROADS AND SITE IMPROVEMENT	$	7,852,168	0.13%	50	50
10991000	HYDROELECTRIC - MAJOR SPARES	$	7,207,631	0.12%	100	100
10315000	HYDROELECTRIC - STEEL RACKS	$	6,220,914	0.10%	40	40
10302100	HYDROELECTRIC - PUBLIC SAFETY/WARNING BOOMS	$	4,066,117	0.07%	15	15
16550000	ADMINISTRATION AND SERVICE BUILDINGS - LAN CABLE	$	3,922,188	0.06%	10	10
10531000	HYDROELECTRIC - CIRCUIT BREAKERS	$	4,048,211	0.07%	50	50
10720000	HYDROELECTRIC - SECURITY SYSTEMS	$	1,987,371	0.03%	10	10
16100000	ADMINISTRATION AND SERVICE BUILDINGS - LANDS	$	591,758	0.01%	N/A	N/A
16560100	ADMINISTRATION AND SERVICE BUILDINGS - ADMINSTRATIVE SYSTEMS SW	$	830,257	0.01%	5	5
16230000	ADMINISTRATION AND SERVICE BUILDINGS - FRAME & METAL	$	11,000	0.00%	25	25
18400000	COMMUNICATIONS - POWER LINE EQUIPMENT	$	591,742	0.01%	15	15
18460000	COMMUNICATIONS - DATA ACQ. EQUIP., MAN MACHINE INTERFACE EQUIPMENT	$	105,828	0.00%	15	15
18630000	COMMUNICATIONS - OPTICAL WIRE	$	644,287	0.01%	25	25
16551000	ADMINISTRATION AND SERVICE BUILDINGS - LAN ELECTRICAL CONNECTING DEVICES	$	777,362	0.01%	5	5
18633000	COMMUNICATIONS - OPTICAL WIRE - REVENUE METERING	$	715,860	0.01%	30	30
18540000	COMMUNICATIONS - ADMINISTRATIVE TELEPHONE EQUIPMENT	$	216,553	0.00%	7	7

ONTARIO POWER GENERATION

SCHEDULE 1A - SUMMARY OF THE CURRENT AVERAGE SERVICE LIFE ESTIMATES AND
GANNETT FLEMING RECOMMENDED AVERAGE SERVICE LIFE ESTIMATES
PREVIOUSLY AND NEWLY REGULATED HYDROELECTRIC ASSETS AS AT DECEMBER 31, 2012

ASSET CLASS #	DESCRIPTION		NBV	% AGE	CURRENT	RECOMMENDED
18600000	COMMUNICATIONS - WOOD POLE, COMMUNICATION CABLE APPARATUS AND BOOTHS	$	77,039	0.00%	40	40
18530000	COMMUNICATIONS - TIMBER AND STEEL STRUCTURES	$	17,738	0.00%	40	40
18100000	COMMUNICATIONS - LAND	$	879	0.00%	100	100
16630000	ADMINSITRATION AND SERVICE BUILDINGS - SYSTEMS & EQUIPMENT	$	132,754	0.00%	20	20
18200000	COMMUNICATIONS - BUILDINGS	$	58,601	0.00%	50	50
18500000	COMMUNICATIONS - RADIO EQUIPMENT	$	5,974	0.00%	15	15
	MINOR FIXED ASSETS	$	4,094,653	0.07%		
NEW	HYDROELECTRIC - NIAGARA FALLS - NEW TUNNEL LINING	$	-	0.00%	N/A	90
NEW	HYDROELECTRIC - BUILDINGS - ROOFING	$	-	0.00%	N/A	30
NEW	HYDROELECTRIC - FENCING	$	-	0.00%	N/A	25
	GRAND TOTAL	**$**	**6,206,228,777**	**100.00%**		

SaskPower

SCHEDULE 1. SUMMARY OF AVERAGE SERVICE LIFE ESTIMATES AND NET BOOK VALUE RELATED TO UTILITY PLANT AT DECEMBER 31, 2009

	Depreciable Property Groups	AVERAGE SERVICE LIFE		SALVAGE		ORIGINAL COST AT	BOOK	
		RECOMMENDED	CURRENT	RECOMMENDED	CURRENT	DECEMBER 31, 2009	DEPRECIATION RESERVE	NET BOOK VALUE
	<u>Generation</u>							
G001	Turbine - Thermal	25	25	0	0	163,372,685	70,207,652	93,165,033
G002	Turbine - Hydro	50	50	0	0	119,105,219	59,368,737	59,736,482
G003	Turbine - Gas	25	25	0	0	138,954,535	23,128,102	115,826,432
G004	Turbine - Wind	20	20	0	0	179,997,344	35,920,599	144,076,745
G005	Generator - Thermal	25	25	0	0	125,435,748	56,242,129	69,193,619
G006	Generator - Hydro	40	40	0	0	101,946,337	49,340,139	52,606,198
G007	Generator - Gas	25	25	0	0	112,120,571	10,866,869	101,253,702
G008	Generator and Gearboxes Wind	15	15	0	0	60,000,671	11,973,627	48,027,044
G009	Boiler - Conventional	25	25	0	0	478,342,241	225,965,865	252,376,376
G010	Boiler-HRSG/OTSG	25	25	0	0	8,199,078	449,522	7,749,556
G011	High Energy Piping	50	50	0	0	70,321,185	50,611,887	19,709,298
G012	High Pressure Feedwater Heaters	20	20	0	0	36,947,166	16,366,695	20,580,471
G013	Low Pressure Feedwater Heaters	35	35	0	0	6,173,682	4,886,987	1,286,695
G014	Condenser	30	20	0	0	18,649,924	8,610,763	10,039,161
G015	Pulverizer, Feeders, Stabilizing Fuel Equipment	35	35	0	0	97,364,236	60,135,206	37,229,029
G016	High Voltage > 1KV	35	35	0	0	37,340,300	21,462,040	15,878,261
G017	Low Voltage < 1KV	25	25	0	0	28,172,995	12,768,355	15,404,640
G018	Underground Ducts and Cable Trays	50	50	0	0	8,134,916	4,589,763	3,545,153
G019	Controls and Protection	25	25	0	0	154,609,597	68,136,992	86,472,605
G020	Flue Gas and Ash System	25	25	0	0	197,018,536	114,436,570	82,581,966
G021	Large Motors, Pumps and Fans	35	35	0	0	34,111,727	21,976,421	12,135,306
G022	Dams, Waterways, Reservoirs	100	100	0	0	239,813,648	149,999,722	89,813,927
G023	Spillways	60	50	0	0	194,096,169	93,679,285	100,416,854
G024	Penstock and Intake Structures	75	75	0	0	120,071,523	63,699,899	56,371,624
G025	Water Treatment Plant Equipment	25	25	0	0	62,867,268	34,573,170	28,294,097
G026	Miscellaneous AIR/Water/Steam/Sewer/Pump/Fire Systems	40	50	0	0	25,496,473	14,313,195	11,183,278
G027	Coal and Auxiliary Fuel Handling Equipment	35	35	0	0	64,229,887	34,964,984	29,264,903
G028	Gas and Auxiliary Fuel Handling Equipment	50	50	0	0	23,393,940	564,826	22,829,114
G029	Lagoon (Ash)	20	20	0	0	61,422,817	33,221,112	28,201,704
G030	Cooling Water Equipment and Lines	40	40	0	0	65,406,794	38,675,059	26,731,735
G031	Boiler House	50	50	0	0	106,784,614	69,880,288	36,904,327
G032	Turbine House	50	50	0	0	148,826,108	86,354,432	62,471,675
G033	Administration /Shop and Auxiliary Buildings	50	50	0	0	83,140,451	42,867,434	40,273,017
G034	Water Treatment Plant and Pond Building	50	50	0	0	34,834,198	22,496,727	12,337,471
G035	Coal Handling Facilities	50	50	0	0	74,254,655	48,050,228	26,204,427
G036	Polish Ponds Recirculation House	50	50	0	0	11,847,079	11,321,455	525,623
G037	Cooling Water Pump House	50	50	0	0	26,616,651	19,870,070	6,746,580
G038	Land Rights	25	25	0	0	1,176,768	270,163	906,606
G039	Roads, Railroads, and Airfields	30	35	0	0	44,500,704	24,137,989	20,362,715
G041	Experimental Emissions Control Equipment	5	5	0	0	6,315,398	5,341,960	973,439
G043	Generator - Diesel	5	5	0	0	169,792	118,897	50,895
	Generation - Turbine - Gas LM6000 Units (Ermine & Yellowhead)*	15	15	0	0	35,944,036	124,906	35,819,130
	Generation - Turbine - Gas H25 Units (Queen Elizabeth Units #4 - 12)*	15	15	0	0	53,168,860	6,936,680	46,231,880
	AMI*	15	15	0	0			
	Total Generation					**3,660,696,525**	**1,728,907,399**	**1,931,788,826**

SaskPower

SCHEDULE 1. SUMMARY OF AVERAGE SERVICE LIFE ESTIMATES AND NET BOOK VALUE RELATED TO UTILITY PLANT AT DECEMBER 31, 2009

	Depreciable Property Groups	AVERAGE SERVICE LIFE		SALVAGE		ORIGINAL COST AT	BOOK	
		RECOMMENDED	CURRENT	RECOMMENDED	CURRENT	DECEMBER 31, 2009	DEPRECIATION RESERVE	NET BOOK VALUE
	Transmission							
S201	Transmission - Conductor	55	50	0	0	138,408,545	71,190,224	67,218,321
S202	Transmission - Devices	35	35	0	0	69,333,149	31,045,776	38,287,373
S203	Transmission - Land Rights	45	45	0	0	52,398,574	22,375,818	30,022,757
S204	Transmission - Switching Station Conductor and Devices	40	40	0	0	14,859,948	10,261,759	4,598,189
S205	Transmission - Power Transformers	50	40	0	0	65,460,033	29,824,857	35,635,177
S206	Transmission - Steel Structures	50	50	0	0	192,233,480	57,549,260	134,684,219
S207	Transmission - Buildings, Roads, Railroads, Airfields	50	50	0	0	10,654,318	4,322,569	6,331,749
S208	Transmission - Wood Structures	45	45	0	0	120,744,987	71,607,757	49,137,231
S211	Transmission - Controls and Auxiliaries	35	35	0	0	88,463,512	42,168,132	46,295,380
S212	Transmission - Line Devices	25	25	0	0	39,032,074	12,806,328	26,225,746
S213	Transmission - Protective Relays	20	20	0	0	5,787,092	1,017,376	4,769,717
S214	Transmission - Site Improvements	40	40	0	0	10,332,488	2,958,591	7,373,897
S215	Transmission - Superstructures	45	45	0	0	29,915,691	12,555,043	17,360,648
	Total Transmission					**837,623,893**	**369,683,490**	**467,940,403**
	Distribution							
S301	Distribution - Power Transformers	40	40	0	0	40,521,031	18,011,622	22,509,408
S302	Distribution - Structures and Foundations	40	40	0	0	10,457,995	3,659,269	6,798,726
S303	Distribution - Substation Equipment	35	35	0	0	92,458,968	43,639,563	48,819,405
S304	Distribution - Overhead Distribution	35	35	0	0	960,587,164	432,805,064	527,782,100
S305	Distribution - Underground Distribution	35	35	0	0	729,374,336	295,806,589	433,567,747
S306	Distribution - Overhead Services	35	35	0	0	39,788,149	14,621,847	25,166,302
S307	Distribution - Underground Services	35	35	0	0	158,156,866	34,385,530	123,771,337
S308	Distribution - Overhead Streetlights	35	35	0	0	20,277,702	14,102,352	6,175,351
S309	Distribution - Underground Streetlights	30	30	0	0	55,650,820	27,050,512	28,600,308
S310	Distribution - Apparatus	35	35	0	0	284,362,775	93,620,869	190,741,906
S311	Distribution - Land Rights	35	35	0	0	7,527,160	1,964,336	5,562,824
S312	Distribution - Buildings and Improvements	40	40	0	0	11,365,715	1,788,974	9,576,742
	Total Distribution					**2,410,528,681**	**981,456,527**	**1,429,072,154**

SaskPower

SCHEDULE 1. SUMMARY OF AVERAGE SERVICE LIFE ESTIMATES AND NET BOOK VALUE RELATED TO UTILITY PLANT AT DECEMBER 31, 2009

		AVERAGE SERVICE LIFE		SALVAGE		ORIGINAL COST AT	BOOK	
	Depreciable Property Groups	RECOMMENDED	CURRENT	RECOMMENDED	CURRENT	DECEMBER 31, 2009	DEPRECIATION RESERVE	NET BOOK VALUE
	Other							
S351	Mechanical Meters and Transformers	15	20	0	0	22,618,862	12,218,070	10,400,792
S352	Electronic Meters and Handheld Meter Readers	8	8	0	0	27,281,707	17,030,173	10,251,533
S405	Mining - Dragline and Equipment	20	20	0	0	3,472,908	911,638	2,561,269
S407	Mining - Transmission Facilities	40	40	0	0	7,636,883	5,285,510	2,351,373
S408	Mining - Miscellaneous Buildings	40	40	0	0	283,100	164,354	118,746
S412	Mining - Surface Rights	15	15	30	30	27,028,744	16,651,448	10,377,296
S501	Shand Greenhouse Building	40	40	0	0	4,761,524	1,863,295	2,898,229
S621	Head Office Building	60	50	50	40	16,667,074	5,571,350	11,095,723
S622	Research and Development Building	50	50	50	50	13,122,716	4,123,678	8,999,038
S623	PCB Storage Building	40	40	0	0	2,823,523	2,823,523	-
S624	Other Buildings	40	40	25	25	46,423,877	12,587,475	33,836,402
S631	Office Machines	10	8	0	0	1,554,108	766,772	787,336
S632	Furniture	15	20	0	0	7,348,200	3,228,645	4,119,556
S633	Modular Furniture	15	20	0	0	12,436,101	3,440,938	8,995,163
S641	Vehicles and Equipment - Light Weight	7	7	7	7	41,648,253	20,843,461	20,804,792
S642	Vehicles and Equipment - Medium Weight	12	12	7	7	31,874,768	13,811,232	18,063,536
S643	Vehicles and Equipment - Heavy Weight	12	12	7	7	26,037,001	12,635,775	13,401,226
S644	Vehicles and Equipment - Track Mounted	25	25	10	10	6,811,216	1,181,327	5,629,889
S645	Vehicles and Equipment - Trailers	20	20	0	0	5,340,455	1,769,508	3,570,947
S646	Vehicles and Equipment - Power Operated	20	20	10	10	7,339,274	2,896,967	4,442,307
S647	Vehicles and Equipment - Miscellaneous	20	20	10	10	3,421,280	1,921,890	1,499,390
S648	Vehicles and Equipment - Forklift Trucks	20	20	10	10	3,419,975	1,491,606	1,928,369
S651	CP&C - Scada Building	50	50	0	0	8,138,452	3,806,616	4,331,836
S652	CP&C - Equipment	10	10	0	0	46,472,723	15,904,980	30,567,743
S653	CP&C - Fibre Optic Cable & Land Rights	35	35	0	0	21,041,513	7,009,944	14,031,570
S654	CP&C - Master Control Equipment	5	5	0	0	12,156,995	8,260,407	3,896,588
S661	Tools and Equipment	5	7	0	0	11,398,088	6,678,726	4,719,362
S671	Computer Development	5	5	0	0	129,917,191	105,225,326	24,691,865
S681	Computer Hardware	4	4	0	0	40,417,903	28,198,998	12,218,905
	Total Other					**588,894,414**	**318,303,630**	**270,590,783**
	TOTAL PLANT					**7,497,743,512**	**3,398,351,046**	**4,099,392,166**

Section:	11	**Page No.:**	Appendix 11.49
Topic:	Financial Results and Forecast		
Subtopic:	Depreciation Expense		
Issue:	ASL vs. ELG		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide a breakdown of costs incurred by MH related to conversion to ELG. This should include internal costs and external costs broken down by consultant, which costs should be further broken down discretely by conversion effort and specific depreciation study.

b) On the same basis as (a), provide an estimate as to the costs that would be incurred related to the preparation of an IFRS-compliant ASL-based methodology.

RATIONALE FOR QUESTION:

To understand the costs related to conversion to ELG compared to continuing to use ASL.

RESPONSE:

a) The process to prepare for the April 1, 2015 conversion to the ELG method involved the selection of additional asset components in combination with the 2010 Depreciation Study, as well as efforts to re-allocate costs from existing asset components to the new component groups (asset conversion). Please note that, for efficiency purposes, the work associated with identifying additional asset components was blended with the work required for completing the 2010 Depreciation Study. For example, interviews and site tours conducted by Gannett Fleming with accounting and operations staff involved both an assessment of potential new components (for conversion to IFRS) and an assessment of the service lives of assets in existing and new component groups (for the 2010 Depreciation Study). Time was not tracked separately between activities pertaining to the identification of additional components and activities pertaining to the depreciation study and as such, it is not possible to segregate many of the costs between the two activities. The breakdown of the costs incurred to date is as follows:

2010 Depreciation Study / Identification of New Asset Components Under IFRS:

Work Performed By	Activities	Cost ($ millions)
Manitoba Hydro staff (Corporate Controller staff, engineers, and management)	- Interview operations staff - Identify additional asset components - Validate new components with engineers, depreciation consultant - Implement IT, SAP related changes - Prepare / review historical accounting records - Provide staff with awareness and understanding of new components - Prepare GRA material, respond to IR's	$0.9
Gannett Fleming	- Engagement to assist with IFRS related issues and complete the 2010 Depreciation Study as follows: ▪ Develop new asset components that comply with IFRS ▪ Develop historic cost and accumulated depreciation for existing and new asset components ▪ Develop depreciation rates for new and existing asset components ▪ Develop additional depreciation scenarios for ASL and ELG procedures with and without net salvage ▪ Provide support for year-end audit questions from Ernst & young	$0.2
Gannett Fleming (Regulatory Support)	- Regulatory support for Manitoba Hydro's 2012/13 and 2013/14 GRA ▪ Assist with the preparation of responses to IR's and undertakings ▪ Participate as a witness	$.05
Total costs		**$1.15**

Please note that the cost of $1.15 million do not include the cost of the 2014 Depreciation Study, or the costs associated with the response to PUB directives 8 & 9 in Order 43/13.

Asset Conversion Costs - New Components:

Asset conversion costs were incurred by Manitoba Hydro staff primarily in the Corporate Controller Division with the assistance of operations staff. These efforts have been ongoing following Manitoba Hydro's completion of the 2010 Depreciation Study in 2012 and, given the high volume of transactional data to analyze, will not be completed until 2015. The overall goal of the conversion effort is to balance efficiency and accuracy in reviewing historical accounting records so as to re-allocate costs between existing and new asset components. For many of the new asset components, historical costs are not readily available as the cost information was not recognized in accordance with the new component such that estimates of the costs have to be made based on recent information and information collected from operations staff. The costs incurred for asset conversion are as follows:

Work Performed By	Activities	Cost ($ millions)
Manitoba Hydro staff (Corporate Controller staff, engineers, and management)	- Review historical accounting / cost records to assess opening costs for each asset component group - Confirm asset costs with engineering staff – develop estimates where necessary - Re-allocate costs between existing and new component groups - Re-allocate costs between components for ongoing projects - Provide staff with awareness and understanding of new components	$1.7
Total		**$1.7**

b) An estimate as to the costs that would be incurred for the preparation of an IFRS-compliant ASL-based methodology would include both a depreciation study and asset conversion. An estimate of these costs is as follows:

Depreciation Study/Identification of Additional Asset Components:

Work Performed By	Activities	Cost ($ millions)
Manitoba Hydro staff (Corporate Controller staff, engineers, and management)	- Interview operations staff - Identify additional asset components - Validate new components with engineers, depreciation consultant - Implement IT, SAP related changes - Prepare / review historical accounting records - Provide staff with awareness and understanding of new components - Prepare GRA material, respond to IR's	$0.7
Gannett Fleming*	- Engagement to assist with IFRS compliant ASL method as follows: ▪ Develop new asset components that comply with IFRS ▪ Develop historic cost and accumulated depreciation for existing and new asset components ▪ Develop depreciation rates for new and existing asset components ▪ Develop additional depreciation scenarios ▪ Provide support for year-end audit questions from Ernst & young	$0.2
Gannett Fleming* (Regulatory Support)	- Regulatory support for future Manitoba Hydro GRA ▪ Assist with the preparation of responses to IR's and undertakings ▪ Participate as a witness	$.05
Total costs		**$.95**

*These estimates not confirmed with Gannett Fleming

Estimated Asset Conversion Costs (IFRS compliant ASL method):

Work Performed By	Activities	Cost ($ millions)
Manitoba Hydro staff (Corporate Controller staff, engineers)	- Review historical accounting / cost records to assess opening costs for each asset component group - Confirm asset costs with engineering staff – develop estimates where necessary - Re-allocate costs between existing and new component groups - Re-allocate costs between components for ongoing projects - Provide staff with awareness and understanding of new components	$1.5
Total costs		**$1.5**

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MANITOBA HYDRO

TABLE 2. CALCULATED ACCRUED DEPRECIATION, BOOK ACCUMULATED DEPRECIATION AND DETERMINATION OF ANNUAL PROVISION FOR TRUE-UP FOR THE TWELVE MONTHS ENDED MARCH 31, 2014

ACCOUNT	DESCRIPTION	SURVIVING ORIGINAL COST AS OF MARCH 31, 2014	CALCULATED ACCRUED DEPRECIATION	BOOK ACCUMULATED DEPRECIATION	ACCUMULATED DEPRECIATION VARIANCE AMOUNT	ACCUMULATED DEPRECIATION VARIANCE PERCENT	PROBABLE REMAINING LIFE	ANNUAL PROVISION FOR TRUE-UP
	(1)	(2)	(3)	(4)	(5) = (3)-(4)	(6) = (5)/(3)	(7)	(8)=(5)/(7)
	COMMUNICATION							
5000B	BUILDINGS	6,955,504	2,274,024	2,947,372	(673,348)	(29.61)	46.5	(14,481)
5000C	BUILDING RENOVATIONS	3,486,352	1,305,730	1,440,484	(134,754)	(10.32)	13.4	(10,056)
5000D	BUILDING - SYSTEM CONTROL CENTRE	15,857,686	3,426,507	3,525,976	(99,469)	(2.90)	59.6	(1,669)
5000G	COMMUNICATION TOWERS	12,362,119	3,715,363	3,350,680	364,683	9.82	42.3	8,621
5000H	FIBRE OPTIC AND METALLIC CABLE	131,559,381	34,203,813	29,139,100	5,064,713	14.81	26.1	194,050
5000J	CARRIER EQUIPMENT	125,921,733	53,806,562	61,816,520	(8,009,958)	(14.89)	12.5	(640,797) **
5000K	OPERATIONAL IT EQUIPMENT	4,821,768	2,609,032	2,691,962	(82,930)	(3.18)	2.6	**
5000M	MOBILE RADIO, TELEPHONE AND VIDEO CONFERENCING	8,862,073	5,738,030	4,438,690	1,299,340	22.64	2.7	481,237
5000N	OPERATIONAL DATA NETWORK	18,817,356	8,386,249	8,136,535	249,714	2.98	4.6	**
5000R	POWER SYSTEM CONTROL	14,264,753	6,710,449	8,431,858	(1,721,409)	(25.65)	10.7	(160,879)
	TOTAL COMMUNICATION	**342,908,725**	**122,175,759**	**125,919,176**	**(3,743,417)**	**(3.06)**		**(143,973)**
	MOTOR VEHICLES							
6000E	PASSENGER VEHICLES	1,145,330	471,876	487,352	(15,476)	(3.28)	5.5	(2,814)
6000F	LIGHT TRUCKS	69,461,644	28,139,845	29,754,753	(1,614,908)	(5.74)	6.9	(234,045)
6000G	HEAVY TRUCKS	73,416,587	27,603,941	29,435,263	(1,831,322)	(6.63)	11.6	(157,873)
6000H	CONSTRUCTION EQUIPMENT	21,130,532	5,649,098	8,256,831	(2,607,733)	(46.16)	17.4	(149,870)
6000I	LARGE SOFT-TRACK EQUIPMENT	15,620,474	3,468,440	4,072,604	(604,164)	(17.42)	20.6	(29,328)
6000J	TRAILERS	18,887,911	4,304,614	4,536,914	(232,300)	(5.40)	25.8	(9,004)
6000K	MISCELLANEOUS VEHICLES	6,114,461	1,529,829	2,553,455	(1,023,626)	(66.91)	10.2	(100,356)
	TOTAL MOTOR VEHICLES	**205,776,939**	**71,167,643**	**79,097,171**	**(7,929,528)**	**(11.14)**		**(683,288)**
	BUILDINGS							
8000B	BUILDINGS - GENERAL	103,251,540	31,082,172	29,525,141	1,557,032	5.01	46.1	33,775 **
8000C	BUILDING RENOVATIONS	37,401,024	12,622,499	10,936,091	1,686,408	13.36	13.1	128,733
8000D	BUILDING - 360 PORTAGE - CIVIL	202,792,903	10,946,359	10,816,316	130,043	1.19	94.6	1,375
8000E	BUILDING - 360 PORTAGE - ELECTRO/MECHANICAL	77,339,398	8,759,755	8,539,762	219,993	2.51	39.9	5,514 **
8000F	LEASEHOLD IMPROVEMENTS - SONY PLACE	1,007,453	631,159	617,462	13,698	2.17	3.7	**
	TOTAL BUILDINGS	**421,792,317**	**64,041,944**	**60,434,771**	**3,607,173**	**5.63**		**169,397**
	GENERAL EQUIPMENT							
9000H	TOOLS, SHOP AND GARAGE EQUIPMENT	87,537,592	42,845,748	39,778,073	3,067,676	7.16	7.3	**
9000K	COMPUTER EQUIPMENT	49,555,418	23,823,338	25,481,868	(1,658,530)	(6.96)	3.0	**
9000L	OFFICE FURNITURE AND EQUIPMENT	26,318,137	9,159,013	9,724,793	(565,780)	(6.18)	13.3	**
9000M	HOT WATER TANKS	881,848	643,731	636,218	7,513	1.17	1.9	**
	TOTAL GENERAL EQUIPMENT	**164,292,994**	**76,471,830**	**75,620,951**	**850,879**	**1.11**		**0**
	EASEMENTS							**
A100A	EASEMENTS	66,021,103	12,551,916	12,901,908	(349,992)	(2.79)	60.8	**
	TOTAL EASEMENTS	**66,021,103**	**12,551,916**	**12,901,908**	**(349,992)**	**(2.79)**		**0**
	COMPUTER SOFTWARE AND DEVELOPMENT							
A200G	COMPUTER DEVELOPMENT - MAJOR SYSTEMS	111,692,382	67,182,098	68,946,077	(1,763,979)	(2.63)	4.7	(375,315)
A200H	COMPUTER DEVELOPMENT - SMALL SYSTEMS	48,787,249	23,415,498	26,099,591	(2,684,093)	(11.46)	6.3	(426,046)
A200J	COMPUTER SOFTWARE - GENERAL	6,701,454	3,603,877	3,490,469	113,409	3.15	2.5	**
A200K	COMPUTER SOFTWARE - COMMUNICATION/OPERATIONAL	4,652,481	2,407,134	1,659,404	747,730	31.06	2.2	339,877
A200L	OPERATIONAL SYSTEM MAJOR SOFTWARE - EMS/SCADA	10,313,958	3,036,286	6,634,595	(3,598,309)	(118.51)	5.6	(642,555)
	TOTAL COMPUTER SOFTWARE AND DEVELOPMENT	**182,147,524**	**99,644,893**	**106,830,136**	**(7,185,243)**	**(7.21)**		**(1,104,039)**
	TOTAL MANITOBA HYDRO	**14,230,425,552**	**4,907,244,608**	**5,381,231,843**	**(473,987,235)**			**(14,330,090)**

* The account has no balance as of March 31, 2014 and rate will be used on a go-forward basis for future additions.
** On amortized accounts any true-up of less than 10% is not considered significant.
*** Community Development costs are amortized over the weighted average life of the physical assets deriving benefit from such expenditures.
**** True-up excluded as exisiting assets in account are fully depreciated.

MANITOBA HYDRO

TABLE 2. CALCULATED ACCRUED DEPRECIATION, BOOK ACCUMULATED DEPRECIATION AND DETERMINATION OF ANNUAL PROVISION FOR TRUE-UP
FOR THE TWELVE MONTHS ENDED MARCH 31, 2014

ACCOUNT	DESCRIPTION	SURVIVING ORIGINAL COST AS OF MARCH 31, 2014	CALCULATED ACCRUED DEPRECIATION	BOOK ACCUMULATED DEPRECIATION	ACCUMULATED DEPRECIATION VARIANCE AMOUNT	ACCUMULATED DEPRECIATION VARIANCE PERCENT	PROBABLE REMAINING LIFE	ANNUAL PROVISION FOR TRUE-UP
	(1)	(2)	(3)	(4)	(5) = (3)-(4)	(6) = (5)/(3)	(7)	(8)=(5)/(7)
	COMMUNICATION							
5000B	BUILDINGS	6,955,504	2,165,736	2,947,372	(781,636)	(36.09)	46.9	(16,666)
5000C	BUILDING RENOVATIONS	3,486,352	1,243,551	1,440,484	(196,933)	(15.84)	13.6	(14,480)
5000D	BUILDING - SYSTEM CONTROL CENTRE	15,857,686	3,263,340	3,525,976	(262,636)	(8.05)	59.6	(4,407)
5000G	COMMUNICATION TOWERS	12,362,119	3,538,441	3,350,680	187,761	5.31	42.6	4,408
5000H	FIBRE OPTIC AND METALLIC CABLE	131,559,381	32,888,279	29,139,100	3,749,179	11.40	26.2	143,098
5000J	CARRIER EQUIPMENT	125,921,733	51,244,346	61,816,520	(10,572,174)	(20.63)	12.7	(832,455)
5000K	OPERATIONAL IT EQUIPMENT	4,821,768	2,484,791	2,691,962	(207,171)	(8.34)	2.7	**
5000M	MOBILE RADIO, TELEPHONE AND VIDEO CONFERENCING	8,862,073	5,464,791	4,438,690	1,026,101	18.78	2.8	366,465
5000N	OPERATIONAL DATA NETWORK	18,817,356	7,986,904	8,136,535	(149,631)	(1.87)	4.7	**
5000R	POWER SYSTEM CONTROL	14,264,753	6,390,903	8,431,858	(2,040,955)	(31.94)	11.1	(183,870)
	TOTAL COMMUNICATION	**342,908,725**	**116,671,082**	**125,919,176**	**(9,248,094)**	**(7.93)**		**(537,907)**
	MOTOR VEHICLES							
6000E	PASSENGER VEHICLES	1,145,330	471,876	487,352	(15,476)	(3.28)	5.5	(2,814)
6000F	LIGHT TRUCKS	69,461,644	28,139,845	29,754,753	(1,614,908)	(5.74)	6.9	(234,045)
6000G	HEAVY TRUCKS	73,416,587	27,603,941	29,435,263	(1,831,322)	(6.63)	11.6	(157,873)
6000H	CONSTRUCTION EQUIPMENT	21,130,532	5,649,098	8,256,831	(2,607,733)	(46.16)	17.4	(149,870)
6000I	LARGE SOFT-TRACK EQUIPMENT	15,620,474	3,468,440	4,072,604	(604,164)	(17.42)	20.6	(29,328)
6000J	TRAILERS	18,887,911	4,304,614	4,536,914	(232,300)	(5.40)	25.8	(9,004)
6000K	MISCELLANEOUS VEHICLES	6,114,461	1,529,829	2,553,455	(1,023,626)	(66.91)	10.2	(100,356)
	TOTAL MOTOR VEHICLES	**205,776,939**	**71,167,643**	**79,097,171**	**(7,929,528)**	**(11.14)**		**(683,288)**
	BUILDINGS							
8000B	BUILDINGS - GENERAL	103,251,540	29,602,068	29,525,141	76,928	0.26	46.3	1,662
8000C	BUILDING RENOVATIONS	37,401,024	12,021,426	10,936,091	1,085,335	9.03	13.3	**
8000D	BUILDING - 360 PORTAGE - CIVIL	202,792,903	10,946,359	10,816,316	130,043	1.19	94.6	1,375
8000E	BUILDING - 360 PORTAGE - ELECTRO/MECHANICAL	77,339,398	8,759,755	8,539,762	219,993	2.51	39.9	5,514
8000F	LEASEHOLD IMPROVEMENTS - SONY PLACE	1,007,453	631,159	617,462	13,698	2.17	3.7	**
	TOTAL BUILDINGS	**421,792,317**	**61,960,767**	**60,434,771**	**1,525,996**	**2.46**		**8,550**
	GENERAL EQUIPMENT							
9000H	TOOLS, SHOP AND GARAGE EQUIPMENT	87,537,592	42,845,748	39,778,073	3,067,676	7.16	7.3	**
9000K	COMPUTER EQUIPMENT	49,555,418	23,823,338	25,481,868	(1,658,530)	(6.96)	3.0	**
9000L	OFFICE FURNITURE AND EQUIPMENT	26,318,137	9,159,013	9,724,793	(565,780)	(6.18)	13.3	**
9000M	HOT WATER TANKS	881,848	643,731	636,218	7,513	1.17	1.9	**
	TOTAL GENERAL EQUIPMENT	**164,292,994**	**76,471,830**	**75,620,951**	**850,879**	**1.11**		**0**
	EASEMENTS							
A100A	EASEMENTS	66,021,103	12,551,916	12,901,908	(349,992)	(2.79)	60.8	**
	TOTAL EASEMENTS	**66,021,103**	**12,551,916**	**12,901,908**	**(349,992)**	**(2.79)**		**0**
	COMPUTER SOFTWARE AND DEVELOPMENT							
A200G	COMPUTER DEVELOPMENT - MAJOR SYSTEMS	111,692,382	67,182,098	68,946,077	(1,763,979)	(2.63)	4.7	(375,315)
A200H	COMPUTER DEVELOPMENT - SMALL SYSTEMS	48,787,249	23,415,498	26,099,591	(2,684,093)	(11.46)	6.3	(426,046)
A200J	COMPUTER SOFTWARE - GENERAL	6,701,454	3,603,877	3,490,469	113,409	3.15	2.5	0 **
A200K	COMPUTER SOFTWARE - COMMUNICATION/OPERATIONAL	4,652,481	2,407,134	1,659,404	747,730	31.06	2.2	339,877
A200L	OPERATIONAL SYSTEM MAJOR SOFTWARE - EMS/SCADA	10,313,958	3,036,286	6,634,595	(3,598,309)	(118.51)	5.6	(642,555)
	TOTAL COMPUTER SOFTWARE AND DEVELOPMENT	**182,147,524**	**99,644,893**	**106,830,136**	**(7,185,243)**	**(7.21)**		**(1,104,039)**
	TOTAL MANITOBA HYDRO	**14,230,425,552**	**4,366,181,882**	**5,381,231,843**	**(1,015,049,961)**			**(29,017,007)**

* The account has no balance as of March 31, 2014 and rate will be used on a go-forward basis for future additions.
** On amortized accounts any true-up of less than 10% is not considered significant.
*** True-up excluded as exisiting assets in account are fully depreciated.

Section:	Appendix 5.6 Depreciation Study	Page No.:	
Topic:	Attachment 2 pages IV-21 & IV-23		
Subtopic:	Depreciation		
Issue:			

PREAMBLE TO IR (IF ANY):

QUESTION:

Please confirm that under Hydro's proposed approach (including adoption of ELG and no asset retirement costs) Hydro's plant in service as at March 31, 2014 shows a negative depreciation variance of $602 million (i.e. is over-depreciated by $602 million).

RATIONALE FOR QUESTION:

To review the 2014 Depreciation Study and implications on rate payers.

RESPONSE:

The calculated accumulated depreciation balance for Manitoba Hydro at March 31, 2014 as determined by Gannett Fleming using the ELG procedure without provision for future retirement costs indicates a surplus of booked accumulated depreciation of $602.6 million.

Section:	Appendix 5.6 Depreciation Study	Page No.:	
Topic:	Attachment 2 pages IV-21 & IV-23		
Subtopic:	Depreciation		
Issue:			

PREAMBLE TO IR (IF ANY):

QUESTION:

Please confirm that under Hydro's proposed approach, the $602 million negative variance is amortized to the benefit of customers via a depreciation "true-up" equalling $16.4 million per year (a rate of approximately 2.7% of the variance amortized per year).

RATIONALE FOR QUESTION:

To review the 2014 Depreciation Study and implications on rate payers.

RESPONSE:

Under Manitoba Hydro's proposed approach, the $602.6 million surplus of booked accumulated depreciation is amortized to the benefit of customers over the remaining life of the specific depreciable asset accounts to which it pertains, by adjusting the depreciation rate for each account to include a "true-up" component.

All else being equal, if there were no additions to the asset base after March 31, 2014, and provided retirements adhered to those predicted by the assigned depreciable lives and IOWA curves, Manitoba Hydro would expect to amortize 10% of the variance within 4 years, 25% within 9 years, 50% within 17 years, 75% within 30 years, and 90% within 45 years, with full amortization by 119 years.

The actual annual amount and percentage of the depreciation variance amortized will change from year to year. In the short term, the amount to be amortized annually will vary from that shown in the depreciation study as the asset base changes over time in response to ongoing addition and retirement activity. Over the longer term, depreciation rates will be adjusted through depreciation studies and interim depreciation rate reviews as the variance for each account becomes fully amortized.

Section:	Appendix 5.6 Depreciation Study	**Page No.:**	
Topic:	Attachment 2 pages IV-21 & IV-23		
Subtopic:	Depreciation		
Issue:			

PREAMBLE TO IR (IF ANY):

QUESTION:

Please confirm that under Hydro's proposed approach, the plant in service as at March 31, 2014 for WPLP shows a negative depreciation variance of $4.3 million and that the variance is amortized to the benefit of customers via a depreciation "true-up" equalling $0.075 million per year (a rate of approximately 1.75% of the variance amortized per year).

RATIONALE FOR QUESTION:

To review the 2014 Depreciation Study and implications on rate payers.

RESPONSE:

The calculated accumulated depreciation balance for WPLP at March 31, 2014 as determined by Gannett Fleming using the ELG procedure without provision for future retirement costs indicates a surplus of booked accumulated depreciation of $4.3 million.

Under Manitoba Hydro's proposed approach, the $4.3 million surplus of booked accumulated depreciation is amortized to the benefit of customers over the remaining life of the specific depreciable asset accounts to which it pertains, by adjusting the depreciation rate for each account to include a "true-up" component.

All else being equal, if there were no additions to the asset base after March 31, 2014, and provided retirements adhered to those predicted by the assigned depreciable lives and IOWA curves, Manitoba Hydro would expect to amortize 10% of the variance within 6 years, 25%

within 15 years, 50% within 32 years, 75% within 51 years, and 90% within 72 years, with full amortization by 119 years.

The actual annual amount and percentage of the depreciation variance amortized will change from year to year. In the short term, the amount to be amortized annually will vary from that shown in the depreciation study as the asset base changes over time in response to ongoing addition and retirement activity. Over the longer term, depreciation rates will be adjusted through depreciation studies and interim depreciation rate reviews as the variance for each account becomes fully amortized.

MANITOBA HYDRO

TABLE 2. CALCULATED ACCRUED DEPRECIATION, BOOK ACCUMULATED DEPRECIATION AND DETERMINATION OF ANNUAL PROVISION FOR TRUE-UP
FOR THE TWELVE MONTHS ENDED MARCH 31, 2014

ACCOUNT	DESCRIPTION	SURVIVING ORIGINAL COST AS OF MARCH 31, 2014	CALCULATED ACCRUED DEPRECIATION	BOOK ACCUMULATED DEPRECIATION	ACCUMULATED DEPRECIATION VARIANCE AMOUNT	ACCUMULATED DEPRECIATION VARIANCE PERCENT	PROBABLE REMAINING LIFE	ANNUAL PROVISION FOR TRUE-UP
	(1)	(2)	(3)	(4)	(5) = (3)-(4)	(6) = (5)/(3)	(7)	(8)=(5)/(7)
	COMMUNICATION							
5000B	BUILDINGS	6,955,504	2,413,593	2,947,372	(533,779)	(22.12)	46.9	(11,381)
5000C	BUILDING RENOVATIONS	3,486,352	1,243,551	1,440,484	(196,933)	(15.84)	13.6	(14,480)
5000D	BUILDING - SYSTEM CONTROL CENTRE	15,857,686	3,465,112	3,525,976	(60,864)	(1.76)	59.6	(1,021)
5000G	COMMUNICATION TOWERS	12,362,119	4,316,592	3,350,680	965,912	22.38	42.6	22,674
5000H	FIBRE OPTIC AND METALLIC CABLE	131,559,381	39,174,600	29,139,100	10,035,500	25.62	26.2	383,034
5000J	CARRIER EQUIPMENT	125,921,733	58,344,665	61,816,520	(3,471,855)	(5.95)	12.7	(273,374)
5000K	OPERATIONAL IT EQUIPMENT	4,821,768	2,484,791	2,691,962	(207,171)	(8.34)	2.7	**
5000M	MOBILE RADIO, TELEPHONE AND VIDEO CONFERENCING	8,862,073	5,464,791	4,438,690	1,026,101	18.78	2.8	366,465
5000N	OPERATIONAL DATA NETWORK	18,817,356	7,986,904	8,136,535	(149,631)	(1.87)	4.7	**
5000R	POWER SYSTEM CONTROL	14,264,753	7,144,616	8,431,858	(1,287,242)	(18.02)	11.1	(115,968)
	TOTAL COMMUNICATION	**342,908,725**	**132,039,215**	**125,919,176**	**6,120,040**	**4.64**		**355,948**
	MOTOR VEHICLES							
6000E	PASSENGER VEHICLES	1,145,330	521,369	487,352	34,017	6.52	5.5	6,185
6000F	LIGHT TRUCKS	69,461,644	29,780,150	29,754,753	25,397	0.09	6.9	3,681
6000G	HEAVY TRUCKS	73,416,587	29,200,922	29,435,263	(234,341)	(0.80)	11.6	(20,202)
6000H	CONSTRUCTION EQUIPMENT	21,130,532	6,492,558	8,256,831	(1,764,273)	(27.17)	17.4	(101,395)
6000I	LARGE SOFT-TRACK EQUIPMENT	15,620,474	4,544,540	4,072,604	471,936	10.38	20.6	22,910
6000J	TRAILERS	18,887,911	5,278,772	4,536,914	741,859	14.05	25.8	28,754
6000K	MISCELLANEOUS VEHICLES	6,114,461	2,160,617	2,553,455	(392,838)	(18.18)	10.2	(38,514)
	TOTAL MOTOR VEHICLES	**205,776,939**	**77,978,928**	**79,097,171**	**(1,118,243)**	**(1.43)**		**(98,581)**
	BUILDINGS							
8000B	BUILDINGS - GENERAL	103,251,540	33,044,112	29,525,141	3,518,972	10.65	46.3	76,004
8000C	BUILDING RENOVATIONS	37,401,024	12,021,426	10,936,091	1,085,335	9.03	13.3	**
8000D	BUILDING - 360 PORTAGE - CIVIL	202,792,903	11,623,441	10,816,316	807,125	6.94	94.6	8,532
8000E	BUILDING - 360 PORTAGE - ELECTRO/MECHANICAL	77,339,398	10,106,216	8,539,762	1,566,454	15.50	39.9	39,260
8000F	LEASEHOLD IMPROVEMENTS - SONY PLACE	1,007,453	631,159	617,462	13,698	2.17	3.7	**
	TOTAL BUILDINGS	**421,792,317**	**67,426,354**	**60,434,771**	**6,991,583**	**10.37**		**123,795**
	GENERAL EQUIPMENT							
9000H	TOOLS, SHOP AND GARAGE EQUIPMENT	87,537,592	42,845,748	39,778,073	3,067,676	7.16	7.3	**
9000K	COMPUTER EQUIPMENT	49,555,418	23,823,338	25,481,868	(1,658,530)	(6.96)	3.0	**
9000L	OFFICE FURNITURE AND EQUIPMENT	26,318,137	9,159,013	9,724,793	(565,780)	(6.18)	13.3	**
9000M	HOT WATER TANKS	881,848	643,731	636,218	7,513	1.17	1.9	**
	TOTAL GENERAL EQUIPMENT	**164,292,994**	**76,471,830**	**75,620,951**	**850,879**	**1.11**		
	EASEMENTS							
A100A	EASEMENTS	66,021,103	12,551,916	12,901,908	(349,992)	(2.79)	60.8	**
	TOTAL EASEMENTS	**66,021,103**	**12,551,916**	**12,901,908**	**(349,992)**	**(2.79)**		
	COMPUTER SOFTWARE AND DEVELOPMENT							
A200G	COMPUTER DEVELOPMENT - MAJOR SYSTEMS	111,692,382	67,557,562	68,946,077	(1,388,515)	(2.06)	4.7	(295,429)
A200H	COMPUTER DEVELOPMENT - SMALL SYSTEMS	48,787,249	23,415,498	26,099,591	(2,684,093)	(11.46)	6.3	(426,046)
A200J	COMPUTER SOFTWARE - GENERAL	6,701,454	3,603,877	3,490,469	113,409	3.15	2.5	**
A200K	COMPUTER SOFTWARE - COMMUNICATION/OPERATIONAL	4,652,481	2,407,134	1,659,404	747,730	31.06	2.2	339,877
A200L	OPERATIONAL SYSTEM MAJOR SOFTWARE - EMS/SCADA	10,313,958	3,251,110	6,634,595	(3,383,485)	(104.07)	5.6	(604,194)
	TOTAL COMPUTER SOFTWARE AND DEVELOPMENT	**182,147,524**	**100,235,181**	**106,830,136**	**(6,594,955)**	**(6.58)**		**(985,792)**
	TOTAL MANITOBA HYDRO	**14,230,425,552**	**4,778,607,417**	**5,381,231,843**	**(602,624,426)**			**(16,398,109)**

* The account has no balance as of March 31, 2014 and rate will be used on a go-forward basis for future additions.
** On amortized accounts any true-up of less than 10% is not considered significant.
*** Community Development costs are amortized over the weighted average life of the physical assets deriving benefit from such expenditures.
**** True-up excluded as exisiting assets in account are fully depreciated.

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Chapter:	**P. Bowman Direct Testimony Section 7**	**Page No.:**	**24**
Topic:	**Depreciation & Amortization**		
Subtopic:			
Issue:	**ELG Depreciation**		

PREAMBLE TO IR:

QUESTION:

a) Please elaborate on how MH's long-lived assets increase in economic value with time and why utilization of ELG causes intergenerational issues.

b) Does the use of ASL address intergenerational issues? Please elaborate.

RATIONALE FOR QUESTION:

RESPONSE:

(a) and **(b)**

Manitoba Hydro's hydro-electric generation stations are the highest cost assets in Manitoba Hydro's system.[1] Hydro-electric generation stations also have the longest expected service lives.[2]

The economic value of long-lived hydro-electric generation assets in particular tend to increase over the life of the asset. This results from several factors, including:

- The capital intensive nature of the long-lived asset, i.e., compared to other sources of generation, hydro-electric generation assets require minimal ongoing operating costs and do not need to address most replacement issues for a very long time period.

[1] As indicated in Table 1 beginning on page 17 of Appendix 5.6 of the Application.
[2] As indicated on pages 7-14 of Appendix 5.6 of the Application.

- Based on past experience, the economic value in the market and to consumers of the electricity provided by the stations tends to increase over the life of the asset (due to inflation impacts at a minimum, for example, on other marginal sources of new generation); in contrast, the annual costs for the hydro generation decline over the economic life due to its capital intensity when using any straight-line depreciation method. The net result is an increase in economic value to ratepayers of the hydro generation asset over its economic life (i.e., the gap between costs and value continues to grow).

- The above impacts are enhanced to the extent that a hydro generation asset is restored and renewed at the end of its economic life rather than abandoned or removed due to obsolescence or lack of any ongoing market value. The likelihood of such restoration for many hydro generation assets (and consistently for most large hydro stations) is an indication of the lack of threat of technological obsolesce during as well as after the asset's long economic life.

An example of some of these factors is provided by the Wuskwatim Power Limited Partnership, which is projected to have operating losses until approximately 2022. Thereafter, positive net income is expected to grow over time. The table below summarizes forecast revenue, expenses and net income at five year intervals based on information provided by Manitoba Hydro. As illustrated in the table, revenues are anticipated to grow over time, while expenses generally decrease in 2025 and beyond, largely as a result of reduced finance expense. This distribution of costs and benefits is consistent with a durable asset that is capital intensive with relatively low operating costs.

Wuskwatim Power Limited Partnership Projected Operating Statement (Millions of dollars)[3]

	2015	2020	2025	2030
Revenue	41	111	134	135
Expenses	119	123	117	103
Net Income	(77)	(13)	17	32

For the purposes of rate regulation ASL, when compared with ELG, helps to partially address intergenerational issues. There are a multitude of methods which better address these issues and lie beyond ASL on the spectrum of potential depreciation methods, such a sinking fund methods or methods based on revenues, but these are not being recommended today by Mr. Bowman and despite their preferential economic profile for hydro generation assets, have fallen out of common use.

ASL helps to somewhat alleviate the risk of over collecting depreciation expense in any year (particularly early years) for such long-lived assets by applying a uniform calculation that remains generally consistent across all years of an asset's expected life. In this manner it mitigates intergenerational cost issues that are apparent in the ELG approach to depreciation for such assets. This is demonstrated by the following considerations:

- As described in the evidence of Patricia Lee, one reason for using ELG is when the risk exists that the asset will not reach the end of its useful life due to technological or other advancements in the field rendering the asset unusable. ELG's method of prioritizing collection or higher forecast retirement in early years can be justified as appropriate if this risk is apparent (discussed further in Patricia Lee's Pre-Filed Testimony). However, Hydro's long-lived hydro generation asset base is generally not subject to risks of technological advancements causing early retirement. Absent such a risk, ASL properly assigns the value of Hydro's assets at all ages of life to ratepayers where ELG would over apply costs in the early years of an asset's life, effectively causing near-term ratepayers to subsidize the costs of longer-term ratepayers.

[3] Figures taken from pages 2 and 3 of 2015/16 General Rate Application, Appendix 11.6.

- The inherent value and level of use in Hydro's assets does not deplete drastically with time but instead systematically endures with the aid of scheduled maintenance and overhauls. Therefore it is reasonable to assume costs can be recovered over the forecast useful life as it can be assumed that Manitoba Hydro will maintain the asset over this period of time, especially for the hydroelectric generation and transmission assets. This is also demonstrated in the life experiences to date of hydroelectric generation and transmission assets, and from Gannett Fleming's jurisdictional comparison of assets used as rationale to elongate the lives of Hydro's asset base in the 2010 and 2014 depreciation studies. As a result of these considerations, from a rate regulation stand point ASL somewhat better matches the intergenerational use of these long-lived assets than ELG, where there is a reasonable expectation that the assets will exist across generations. Any decrease in value of these assets is more than accounted for under the expected retirements in ASL, and therefore there is no regulatory requirement to expedite the collection of depreciation costs for these assets.

- The Hydro asset costs are known. With large hydroelectric generation and transmission assets the majority of costs occur upfront, not later over the asset's life. As there is minimal risk for ratepayers that unplanned costs will arise over the life of the asset it is not required to over collect depreciation in the early or later years of the assets planned life. In this way, ASL does help alleviate any intergenerational issues that would otherwise occur with ELG.

- Inflationary increases in value of the hydroelectric asset outputs are somewhat better represented in ASL than in ELG. The benefits of hydroelectric produced unit of power (in a cents/Kw.h metric) provide ratepayers more value towards the latter part of a hydroelectric assets life than at the beginning. In this sense ASL, or sinking-fund type methods (similar to what Newfoundland & Labrador Hydro used to employ which even further lowers the depreciation expense in the early years of an assets life than ASL, and further increases the depreciation expense in the later years of an assets life) better matches the benefit seen by ratepayers with the costs over the asset's life.

- Due to continual replacement and additions to discrete parts of a utility's asset base (e.g., addition of Keeyask), the promise of ELG providing higher depreciation expense early on in exchange for lower depreciation expense later does not play out in practical terms, since the assets that may have transitioned to the older, lower depreciation part of their life curve become dwarfed by new modern priced assets early in their life curve. The end result is that an ELG approach with a hydro-based utility such as Manitoba Hydro (where ongoing hydro generation expansion can still occur) leads to ratepayers continuing to pay higher rates each and every year in exchange for no relief at any point in the future so long as any new hydro or transmission development or re-development is occurring. In different words, this higher cost profile with ELG is simply matched by a higher cash generation for the utility perpetually, which is one key reason that ELG is preferred by many utilities particularly private-sector firms. In this regard ELG versus ASL for a utility such as Manitoba Hydro is not an intergenerational issue whatsoever in any normal sense of such terms, as the ELG approach in this instance provides no "trade-off" where lower costs are captured by customers in some defined future in return for higher costs today.

RATIONALE FOR REFUSAL TO FULLY ANSWER THE QUESTION:

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Chapter:	**P. Bowman Direct Testimony Section 7.1**	**Page No.:**	**25 Line 8**
Topic:	**Depreciation Methodology for Peer Hydro Electric Utilities**		
Subtopic:			
Issue:	**Peer Utility Depreciation Practices**		

PREAMBLE TO IR:

QUESTION:

a) Please provide a listing of Peer Canadian hydroelectric generation companies that utilized ASL for depreciation purposes.

RATIONALE FOR QUESTION:

RESPONSE:

(a)

Mr. Bowman does not maintain a comprehensive list of utilities on a routine basis. For the purposes of this response, Mr. Bowman notes that the following table was originally provided in the 2012 Pre-Filed Testimony of Patrick Bowman. It has been updated to present day for the purposes of this response.

Also note the following incorrect information filed by Hydro in this proceeding:

- In response to MIPUG/MH II-7, Hydro (Gannet Fleming) incorrectly states that Newfoundland & Labrador Hydro uses ELG, when the utility actually uses ASL as outlined in the Board of Commissioners of Public Utilities Order P.U. 40 (2012) at the culmination of the 2012 Depreciation Methodology review, link provided below.

- In response to PUB/MH I-42b, Hydro (Gannett Fleming) incorrectly states that Qulliq Energy Corporation (formerly Nunavut Power) uses ELG. This is not correct as the utility uses the ASL method as shown in the QEC 2010 GRA[1]

Table 1: Depreciation Methods for Crown-Owned Canadian Utilities

Utility	Depreciation Expense Calculation Method	Study Date
BC Hydro	Average Service Life Method[2]	Gannett Fleming in 2006
BC Transmission Corporation	Average Service Life Method[3]	Gannett Fleming in 2005
Newfoundland and Labrador Hydro	Average Service Life Method[4]	Gannett Fleming in 2011
SaskPower	Average Service Life Method [5]	Gannett Fleming in 2011
Yukon Energy Corporation	Average Service Life Method[6]	KPMG in 2012
Qulliq Energy Corporation (Nunavut)	Average Service Life Method[7]	Gannett Fleming in 2010
Northwest Territories Power Corporation	Average Service Life Method[8]	Gannett Fleming in 2012
FortisBC	Average Service Life Method[9]	Gannett Fleming in 2011
Ontario Power Generation	Average Service Life Method[10]	Gannett Fleming in 2013
Nova Scotia Power	Average Service Life Method[11]	Gannett Fleming in 2010
Hydro One	Average Service Life Method[12]	Foster Associates 2011

[1] http://www.qec.nu.ca/home/index.php?option=com_docman&task=doc_download&gid=542 at page 183 of the pdf document.
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Chapter:	**P. Lee Direct Testimony**	**Page No.:**	**3 Line 8**
Topic:	**ELG vs. ASL**		
Subtopic:			
Issue:	**Characteristics of Depreciation Methodology**		

PREAMBLE TO IR:

QUESTION:

a) With respect to each of the characteristics listed, please summarize in a table whether ASL or ELG meets each of the characteristics with reasons.

RATIONALE FOR QUESTION:

RESPONSE:

(a)

ASL meets each of the characteristics listed on page 3, lines 8-14; in its pure form, ELG does also. The pure form of ELG means that a separate ELG rate is designed for each age of each vintage, vintage actuarial plant and reserve data are required to be maintained, and an annual monitoring and reserve true-up is developed each year to measure any over or under recovery. MH does not appear to be proposing implementing ELG in its pure form but rather some hybrid form. A retirement pattern and life are applied to the plant balance of each vintage. The retirement pattern and life for ELG are statistically developed in the same way as they are for ASL. In ELG though, the retirement pattern and life separates each vintage into hypothetical equal life groups. Hypothetical in the sense that the equal life groups are formed based on the selected retirement pattern and life that may or may not reflect how those particular assets have been living, or are expected to live in the future. Because of how the equal life groups are formed, the physical units in each equal life group cannot be identified. The statistical estimation simply establishes the number of units or dollars in each equal life group. This is one reason why it is critical to have vintage plant data if the theoretically correct ELG is to be implemented. The table below explains why ASL or ELG meets the characteristics listed on page 3.

	ASL	**ELG**	**Reasons**
Matching costs with benefits	Yes, if there is a reserve true-up as part of each category's depreciation rate.	Theoretically yes if rates are established for each age of each vintage, if vintage plant and reserve data are maintained, and if there is an annual expense and reserve true-up. However, MH is not proposing to implement the theoretically correct ELG in which a separate ELG rate is developed for each age; it is proposing a composite ELG rate for all vintages of the entire account/category/component. It is therefore not clear whether MH's hybrid ELG rate will match costs with benefits.	Theoretically correct ELG is not practical to implement. The administrative and regulatory costs to maintain vintage plant and reserve data, to annually monitor each vintage for over or under recovery, and to maintain separate ELG rates for each age have not been quantified nor considered by MH to determine whether the costs of implementation outweigh the benefits of the mechanism. Both ASL and ELG will recover the total investment in the category/account/component over the period the related assets are serving the public, if there is a reserve true-up added and if all the requisite ELG requirements are met. Under the original ELG concept, separate annual monitoring of the vintage plant activity and the vintage reserve level is required. This is necessary so that any over or under

	ASL	ELG	Reasons
			recovery can be measured and an end-of-year depreciation expense and reserve correction for each vintage can be made. The over or under recovery is due to projected life patterns not being realized. For ASL, a reserve imbalance can be calculated and a true-up can be made at the time depreciation rates are reviewed and revised. Certainly ELG is more aggressive than ASL in the earlier years. Given that MH's assets are capital intensive, very long lived (some in excess of 100 years), and increase not decrease in economic value as they age, MH's hybrid form of ELG may not match costs with benefits.
Avoiding intergenerational equity issues	Yes, with a reserve true-up as implemented by MH. Over the life of the property group, full	Theoretically yes, if implemented on a going-forward basis to new additions, if ELG rates are established for each age of each vintage, if vintage plant and reserve data are maintained, and if there is	Reserve imbalances, to the extent they exist, represent a failure in the past to recover. They can and will occur under either ASL or ELG to the extent that the plant under study does not live in accord with the

	ASL	ELG	Reasons
	recovery will be achieved.	an annual monitoring and reserve true-up provision. However, MH is proposing a hybrid form of ELG where a single composite ELG rate is developed for the entire account/category/component investment. Applying ELG to embedded plant investments creates intergenerational inequities by assuming that ELG has always been the applied procedure. Depreciation rates are designed and implemented on a prospective basis. Logic dictates that a change in depreciation procedure also be implemented prospectively. The MH 2005 depreciation study indicated that vintage plant data is not maintained; aged data was simulated so statistical techniques could be used as though the data were in fact actual. This is another reason that the hybrid ELG rates, if	selected curve shape (retirement pattern) and life estimate. Reserve true-ups are necessary to correct these intergenerational inequities and to provide full recovery. If ELG is to meet the alleged characteristic of being the best mechanism for matching depreciation expenses (recovery) to the using up of the related assets (consumption), then the ability to measure that recovery and consumption is critical for each vintage to which ELG is applied. That measurement can only theoretically be made if the age of the assets which have retired during any given year (vintage actuarial data) is known. To the extent the investment/age mix of plant retiring during a year does not equal the amount of retirements at the age/mix predicted under the ELG rates, there has been an over or under recovery.

	ASL	ELG	Reasons
		approved, should be implemented on a going forward basis for new additions. The embedded should be subject to ASL with a reserve adjustment. The embedded balance will decrease over time and ultimately be fully recovered and retired.	Without methods and procedures to monitor and analyze the data within each group of property required in using ELG and without detailed information by vintage for each category, the PUB and other interested parties will not be in a position to review life estimates or to determine depreciation expense applicable to that plant used in providing service. Regulatory review ensuring there has not been any under or over recovery of investment through the depreciation rates cannot be assured. A major disadvantage of ELG is with the administrative costs of maintaining the requisite vintage data and performing the annual reviews and reserve true-ups. MH has not quantified these costs. If MH claims that vintage plant and reserve data, a separate ELG rate for each age of each vintage, and an annual reserve

	ASL	ELG	Reasons
			true-up rate are too costly and burdensome for it to maintain, then the resulting lives and depreciation rates simply reflect a mathematical exercise with no real added precision. At that point the hybrid ELG is no better than any other procedure. With a prospective application, vintage reserve data should be required to be maintained so that an annual reserve true-up for ELG vintages can be made as needed.
Transparency of method, calculations, intentions, and resulting expenses for use in setting customer rates	Yes. The same ASL depreciation rate is applied to each vintage of each account. In this way each vintage is treated as though it will experience the life of the group.	Theoretically yes, if a separate ELG rate is established for each age of each vintage, and vintage plant and reserve data are maintained. However, MH proposes a hybrid ELG rate that does not meet this characteristic.	Most of the calculations in developing the ELG rate are done within the computer. The reason for this is the voluminous number of rates to track for each vintage. A separate ELG rate is calculated for each age of each vintage. Over a period of three years, this equates to three separate ELG rates for each account/category/component. Over a period of 10 years, this would be

	ASL	ELG	Reasons
			10 separate ELG rates for each account/category/component for each age plus an additional annual reserve true-up rate. In order to reduce the number of separate rates for each vintage, the mathematics is performed within the computer and the process simplified by developing one ELG rate representing the composite of the separate ELG rates for each age within an account/category/component. Thus, one hybrid ELG rate would apply to the account/category/component rather than a different rate for each age of each vintage. Application of a composite rate is not the same and does not yield the same expenses as applying separate ELG rate for each age to the investment surviving at that age. ASL is based on the concept of averages for the group (account/category/component) as a

	ASL	ELG	Reasons
			whole. Some assets within the group will live shorter than the average life while others may live longer than the average life. The life pattern is not necessarily representative of any vintage, but is intended to reflect the average pattern expected from the entire group. Within the group, any given year of activity may experience more or less retirements than indicated by the curve shape. By the very nature of a group, there can be a variation of service lives among the contained items. A major disadvantage of ELG is with the administrative costs of maintaining the requisite vintage data and performing the annual reviews and reserve true-ups. These costs have not been quantified. If vintage plant and reserve data, a separate ELG rate for each age of each vintage, and an annual reserve true-up rate are too costly and

	ASL	ELG	Reasons
			burdensome for a company to maintain, then the resulting lives and depreciation rates simply reflect a mathematical exercise with no real added precision. In which case, simply accept ELG as a mechanism to increase cash flow and forget the purist argument of ideally matching recovery with consumption.
Quality of data in determining an appropriate retirement pattern and life	Yes. Vintage data is not requisite for ASL because the account is not divided. ASL assumes that some items in the group will live longer than the average life while others will live shorter but the account as a whole will live the average.	Theoretically yes if adequate data is available for the proper application of ELG and if recordkeeping and reporting practices will enable monitoring the reasonableness of the rate of allocation of original cost. According to MH's 2014 depreciation study, it does not have vintage data for many of its accounts.	For ELG to meet the alleged characteristic of being the best mechanism for matching depreciation expenses (recovery) to the using up of the related assets (consumption), then the ability to measure that recovery and consumption is critical for each vintage to which ELG is applied. That measurement can only theoretically be made if the age of the assets which have retired during any given year (vintage actuarial data) is known. To the extent the investment/age mix of plant retiring during a year does not equal the

	ASL	ELG	Reasons
			amount of retirements at the age/mix predicted under the ELG rates, there has been an over or under recovery. Without methods and procedures to monitor and analyze the data within each group of property required in using ELG and without detailed information by vintage for each category, the PUB and other interested parties will not be in a position to review life estimates or to determine depreciation expense applicable to that plant used in providing service. Regulatory review ensuring there has not been any under or over recovery of investment through the depreciation rates cannot be assured. While vintage data would be advantageous using the ASL method, it is not a critical requirement because the concept is based on averages. A disadvantage of ELG is with the

	ASL	ELG	Reasons
			increased administrative costs of maintaining the requisite vintage data and performing the annual reviews and reserve true-ups. These costs have not been quantified. It cannot be said whether taking into consideration these costs would be less costly or more costly than MH's estimated $2 million to additionally componentize for ASL to be compliant with IFRS. [If MH estimates costs of maintaining vintage plant and reserve data, a separate ELG rate for each age of each vintage, and an annual reserve true-up rate are too costly and burdensome then there is essentially no added benefit or accuracy changing to a new depreciation procedure. ELG rates will be the result of a mathematical exercise with no real added precision. The purist argument for ELG of ideally matching recovery with consumption

	ASL	ELG	Reasons
			will not exist.] An advantage of using ASL is the simplicity of the approach and wide acceptance.

RATIONALE FOR REFUSAL TO FULLY ANSWER THE QUESTION:

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Chapter:	P. Lee Direct Testimony	Page No.:	9 -10
Topic:	Data Requirement for ELG		
Subtopic:			
Issue:	Sensitivity to Iowa Curve Selection		

PREAMBLE TO IR:

QUESTION:

a) To what degree is the ASL procedure subject to variability in depreciation expense from using Iowa curves of different shapes. Please compare Table 4 prepared on an ASL basis with ELG and comment on any differences.

b) Please indicate to what extent the depreciation varies under ELG versus ASL based on the relative heights of the modes of the frequency curves with each Iowa curve family.

c) Please describe the investments MH would be required to make and the costs to maintain actuarial and vintage reserve data.

RATIONALE FOR QUESTION:

RESPONSE:

(a)

Effect of Curve Shape on ASL Depreciation Expenses							
		Selected Curve Shape					
		Iowa L0		Iowa S1		Iowa R5	
Activity Year	Age	Expenses $	Rate %	Expenses $	Rate %	Expenses $	Rate %
1	0.5	20,000	20.0	20,000	20.0	20,000	20.0
2	1.5	19,421	20.0	19,648	20.0	20,000	20.0
3	2.5	17,390	20.0	19,389	20.0	20,000	20.0

The above table illustrates depreciation rates and resulting expenses on an ASL basis. Compared to Table 4 in Ms. Lee's pre-filed testimony on an ELG basis, one can see that:

- ASL rates are generally lower than ELG rates in the early years, regardless of curve shape.
- The ASL depreciation rates are the same for each activity year; they do not change by vintage compared to the ELG depreciation rates.
- While the curve shape selection does have a small impact on the depreciation expenses using ASL, it is not as dramatic as using ELG. This indicates the sensitivity to curve shape is not as great using ASL.

(b)

The lower the height of the mode of a frequency curve, the more early retirements or infant mortality is expected. Recent vintages of a category are likely to contain more dollars than older vintages. The average dollar in any category is somewhat newer than the midpoint of the lifespan of the overall plant, which in turn usually increases depreciation when ELG is compared to ASL.

(c)

To implement ELG in its pure form, at a minimum, MH should be required to maintain vintage plant and reserve data for new additions to each account an ELG rate is being applied. Without detailed information by vintage for each category for which an ELG rate is applied, regulatory review ensuring that companies have no under or over recovered their investment through depreciation rates cannot be assured. A separate ELG rate should be applied to each age of each vintage in calculating depreciation expenses. Additionally, MH should be required to file annual updates for any needed reserve and depreciation expense true-ups needed. Such data and recordkeeping are necessary to enable monitoring of the reasonableness of the ELG rate. There are also additional regulatory costs associated with annual monitoring and updates that should be considered. The costs for these requirements are administratively time consuming and costly; costs that have not been quantified by MH.

While MH estimates possible costs associated with componentizing for ASL to be IFRS compliant, it has not mentioned costs to maintain the vintage data necessary for ELG or the additional staff or regulatory time that might be needed. Companies in the United States have found that these recordkeeping requirements makes ELG, in its pure form, more costly overall.

RATIONALE FOR REFUSAL TO FULLY ANSWER THE QUESTION:

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Chapter:	**P. Lee Direct Testimony**	**Page No.:**	**3**
Topic:	**Appendix 11.49**		
Subtopic:			
Issue:	**ASL vs. ELG Depreciation Methodology Comparison**		

PREAMBLE TO IR:

QUESTION:

a) Please provide an assessment of the Gannett Flemings extrapolation analysis comparing ASL versus ELG found in Appendix 11.49.

RATIONALE FOR QUESTION:

RESPONSE:

(a)

Gannett Fleming's extrapolation analysis found in Appendix 11.49 appears to be mathematically correct. However, the ELG rates reflect composite rates of the separate ELG rates for each age. Under theoretically correct ELG, the separate ELG rates should be applicable for each age rather than a composite rate for the entire group. Ms. Lee is not an accountant and cannot say one way or another if the components listed are correct and necessary for ASL to be IFRS compliant. What can be said is that if vintage plant and reserve data is not maintained for each component category for which a separate ELG rate is applied, application of ELG will provide no better accuracy in depreciation rates or expenses. Just as additional componentization for IFRS ASL compliancy may be costly and require administrative efforts to maintain, so may the correct implementation of ELG.

- The difference between ASL depreciation expenses and ELG expenses is one of timing. The ASL method is based on the overall average service life of the all assets in a group. ELG is dependent on a curve shape to divide the investment into equal life groups with presumably the same lives. Each ELG group is depreciated with a separate rate for each age. The resulting expense are then summed for total depreciation for the component group.

- The accuracy of the overall ASL depreciation expense depends on the extent to which over and under depreciation is balanced for the group of assets. The accuracy of the ELG expense depends on the vintage plant and reserve data so accurate estimates of the subgroup lives can be made.

- Assuming that the expenses under ELG would be very similar as those produced using an IFRS-compliant ASL method, consideration of the additional administrative and regulatory costs involved with both ELG and IFRS-compliant ASL should be considered. Implementing theoretically correct ELG to determine annual depreciation expenses will result in applying a separate ELG rate to each age of each vintage, maintaining vintage actuarial plant and reserve data, annual reserve true-ups between actual and projected activity, ELG may result in higher overall expense compared to implementing IFRS-compliant ASL including costs associated with additional componentization.

Ms. Lee is not an accountant. She cannot say with specificity if the additional componentization MH and Mr. Kennedy assert will be needed for IFRS purposes is true. Gannett Fleming states that componentization for IFRS-compliance "would require a detailed analysis of virtually all of the current Manitoba Hydro accounts. Such an analysis would require the detailed manual review of over 70 years of detailed project capitalization records, many years of detailed retirement transactions, and a detailed retirement transactions, and a detailed review of the current investment in all accounts"[1]. These reviews are required in order to determine the amount of investment by installation year for accounts that could be componentized further, and to appropriately develop retirement rate analysis for the support of an average life estimate for each of the new components. Additionally, the accumulated depreciation accounts would require the same level of componentization as the related asset accounts. The same analysis and review would appear to be very helpful in establishing the equal life groups under ELG.

RATIONALE FOR REFUSAL TO FULLY ANSWER THE QUESTION:

[1] Quoted from Appendix 11.49. Response to PUB Decision 43/13, February 27, 2015, page I-3 regarding the scope of study to reasonably respond to PUB Order 43/13.

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M A N I T O B A	**Order No. 43/13**
THE PUBLIC UTILITIES BOARD ACT	**April 26, 2013**

Before: Régis Gosselin, B.A., M.B.A., C.G.A., Chair
Raymond Lafond, B.A., C.M.A., F.C.A., Member
Larry Soldier, Member

FINAL ORDER WITH RESPECT TO
MANITOBA HYDRO'S 2012/13 AND 2013/14
GENERAL RATE APPLICATION

6.2.0 Board Findings

The Board accepts the depreciation rates applied April 1, 2011, which rates reflect the changes in service lives and the true-up of the accumulated depreciation surplus for the two test years. The Board also accepts Manitoba Hydro's position that net salvage should be removed from depreciation rates when International Financial Reporting Standards are implemented rather than during the test years.

The Board understands that Manitoba Hydro is enhancing its asset condition assessment tools and will direct Manitoba Hydro to complete an Asset Condition Assessment Study no later than the filing of an updated depreciation study with the Board.

With respect to the possible switch from an Average Service Life methodology to Equal Life Group, the Board notes that both are acceptable methodologies under International Financial Reporting Standards and that any proposed changes would take place in 2015/16, which is beyond the test years. The Board understands that the decision to move towards Equal Life Group is a policy decision very much interrelated with other International Financial Reporting Standards accounting policy considerations. Given continued uncertainty regarding the application of International Financial Reporting Standards on rate-regulated entities, the Board will expect Manitoba Hydro to file additional information, including an update on any accounting policy changes, that will impact depreciation rates at the next General Rate Application.

The Board also is concerned that not enough information has been provided to date to assess the true impact on ratepayers of a switch to Equal Life Group. As such, the Board will require Manitoba Hydro to file additional information, including a determination of depreciation rates and schedules based on the Average Service Life methodology, to provide a meaningful comparison between the two approaches. The Board further expects Manitoba Hydro to file, as part of its next General Rate Application, additional information to specify what, if any, increased componentization is required, and at what cost. The work undertaken by Manitoba Hydro and Gannett Fleming Inc. with respect to component groupings to date can serve as a foundation towards determining what additional component groupings and costs, if any, are required for an International Financial Reporting Standards-compliant Average Service Life methodology.

The Board will require Manitoba Hydro to provide a comparison, for the next General Rate Application, of the impact on the Integrated Financial Forecast of an Average Service Life methodology (without net salvage) and an Equal Life Group methodology (without net salvage), where each of the accounting methodologies are applied to planned major capital additions in the Integrated Financial Forecast. Given the forecast to increase net plant by over $21 billion over a 20 year period, it will be important to understand the implications on ratepayers of using each approach at the next General Rate Application.

The Board further expects Manitoba Hydro to file, as part of its next General Rate Application, additional information to support Manitoba Hydro's view that an Average Service Life methodology compliant with International Financial Reporting Standards requires increased componentization. As part of this information, the Board expects to see evidence as to what level of componentization would be required, and how such level of componentization would increase Manitoba Hydro's costs, if at all.

components that would be required.

As indicated in the Manitoba Hydro rebuttal evidence in Section 2.2.4, conversion to the ELG procedure upon adoption of the IFRS would require a lesser level of componentization than would be required in the circumstances of the continued use of the ASL. It is my view that if the ELG procedure is not adopted, Manitoba Hydro would need to undertake additional review of its level of componentization and will likely require a number of additional new accounts.

I also advised that the IFRS would no longer permit the inclusion of net -- negative salvage percentages into the depreciation rate calculations for financial disclosure purposes. Additionally, and as indicated previously, Gannet Fleming advised that the account structure would require revision in order to comply with IAS 16. For example, I noticed that the generation accounts would require a significant increased level of componentization.

MS. PATTI RAMAGE: Could you outline the process you've followed in the completion of the depreciation study that's submitted as Appendix 5.7 in this proceeding?

MR. LARRY KENNEDY: Certainly. Normally, a depreciation study for an existing client

Fleming's recommendation with respect to all SaskPower assets that there need not to be a positive or negative salvage value.

MR. LARRY KENNEDY: SaskPower has, from day 1 within the organization -- or, I should say, at least for as many years as I could find history -- recorded salvage at the time of expenditure; in other words, expensed their salvage costs.

The -- going -- moving into the world of IFRS, that was an easy policy for them to -- to suggest that they would continue. In other words, their current practice of not booking salvage and booking salvage straight to the income statement flowed very easily into the transition to IFRS.

So the -- their -- their policy decision was that they wished to continue recording no-net salvage within the depreciation rates. I respected that policy decision and -- and my -- my depreciation rates and calculations assumed a zero percent net salvage -- zero negative net salvage.

There's some circumstances where we have positive salvage.

MR. ANTOINE HACAULT: Do you have any idea, sir, when we're talking about the dams, waterways and reservoirs, what amount was expensed at the beginning?

MR. LARRY KENNEDY: You mean in terms of original cost?

MR. ANTOINE HACAULT: Because I understood your answer that they assign right from get-go some kind of a salvage value.

Was it positive, negative, and what was the amount?

MR. LARRY KENNEDY: Oh, no, sir, if -- if that's the way it came across, then I -- then I misspoke, and I want to clarify that. The -- right from the get-go they had assigned a zero percent net salvage within their depreciation rates. As they had incurred expenditures, they put them straight to the income statement.

In other words, they have from the -- from day 1, recorded net salvage in much the same manner as -- as Manitoba Hydro is proposing to record net salvage upon the implementation of the informa -- of the International Financial Reporting Standards.

So, I'm -- I'm not sure if I understood your question correct, so I want to be clear that they had not had net salvage -- net-negative salvage in their depreciation rates from day 1.

MR. ANTOINE HACAULT: And am I right in

understanding then, the column that says "Salvage" at pages 199, 200, and 201 represents the recommendation of Gannett Fleming, but based on the policy of the company?

MR. LARRY KENNEDY: That's correct, sir. It -- we -- we accepted the -- the policy of the company that they wished to continue to record no net-negative salvage in their rates.

We left those columns in the -- in the study. As you notice at page 201, there's some indications of positive salvage that the company wished to -- to continue to include in their depreciation rates.

MR. ANTOINE HACAULT: So Gannett Fleming didn't conduct a separate study or exercise its independent opinion on the issue of salvage value.

Is that correct?

MR. LARRY KENNEDY: We did not, nor were we asked to as part of the engagement.

MR. ANTOINE HACAULT: So although the heading says, "recommended," we read that "recommended" in accordance with the policy of the company. It's not Gannett Fleming's opinion.

MR. LARRY KENNEDY: That's correct, sir.

(BRIEF PAUSE)

MR. LARRY KENNEDY: It's -- Mr. Rainkie's reminding me of something here too, and -- and I think it's important to bring out that SaskPower is -- is regulated in -- in a different format than a lot of utilities. And I'm not certain that they would have thought about the concept of net-negative salvage in the same way that most rate-regulated companies would. So I'm -- I put that out there, just -- ev -- every company is different and every company is unique, and you need to look at the facts and circumstances of -- of each company as -- as we go through these studies.

MR. ANTOINE HACAULT: Now, sir, could you turn to page 177 of our book of documents? Page 177. It's an extract of a one (1) page of transcript. And I just wanted to clarify one (1) of the statements that you had made in response to Mr. Peters's question. And Mr. Peters's question starts at line 4. And he had asked your understanding that the Ontario Energy Board had prescribed ASL methol -- methodology over Equal Life Groups.

And you provide an answer, but there's -

- the answer is not very clear, starting at line 11. It's recorded, and I'm quoting:

> "The [dash, dash] -- that's the case, but all the Ontario utilities that I'm aware of use equal life dash] -- or use Average Service Life."

Am I correct in understanding that we should read that sentence to be:

> "That's the case [comma], but that all the Ontario utilities that I'm aware of use Average Service Life."

Is that how that sentence should read?

MR. LARRY KENNEDY: Yes, I -- I think I was a bit confused in Mr. Peters's question above that. We had indicated -- prescribed the ASL methodology over the -- over the Equal Life Groups. And that was in my head -- on the -- on the spur of the moment I was, I think, con -- not very clear in my answer.

I think you've summarized my answer correctly, sir. And if I could put that on the record that should have read -- should have read:

> "That's the case, but all the Ontario utilities that I'm aware of use the Average Service Life."