Manitoba Hydro Cost of Service Study Review - Board Counsel Book of Documents

Manitoba Hydro
Prospective Cost Of Service Study - Amended
March 31, 2014
Revenue Cost Coverage Analysis

SUMMARY

Customer Class	Total Cost ($000)	Class Revenue ($000)	Net Export Revenue ($000)	Total Revenue ($000)	RCC % Current Rates
Residential	629,213	588,630	39,179	627,809	99.8%
General Service - Small Non Demand	132,465	135,035	8,017	143,052	108.0%
General Service - Small Demand	138,205	136,080	8,352	144,432	104.5%
General Service - Medium	200,142	186,797	12,190	198,987	99.4%
General Service - Large 0 - 30kV	99,706	84,956	6,058	91,014	91.3%
General Service - Large 30-100kV*	61,612	57,808	3,807	61,614	100.0%
General Service - Large >100kV*	204,538	189,258	12,514	201,772	98.6%
*Includes Curtailment Customers					
SEP	968	826	-	826	85.4%
Area & Roadway Lighting	21,997	21,630	419	22,049	100.2%
Total General Consumers	1,488,846	1,401,019	90,537	1,491,556	100.2%
Diesel	9,948	6,612	626	7,238	72.8%
Export	254,070	345,233	(91,163)	254,070	100.0%
Total System	1,752,864	1,752,864	-	1,752,864	100.0%

REFERENCE: Undertaking #33, Transcript page 372

QUESTION:

a) MIPUG to provide list of Manitoba Hydro changes in methodology from previous Cost of Service Studies, and indicate where MIPUG agrees or disagrees.

ANSWER:

(a)

The below sets out the key items as indexed in MIPUG MFR-5, on which Hydro now seeks to revise previously ordered methods. The table also notes Mr. Bowman's recommendation from the Pre-Filed Testimony, and the interim position of MIPUG (pending completion of the evidentiary phase of the hearing), and notes those on which MIPUG is in agreement with Manitoba Hydro (highlighted in bold italics).

Issue	***Last Approved by PUB (116/08)[1]***	***Manitoba Hydro PCOSS14-Amended***	***Bowman Pre-Filed Testimony***	***MIPUG Interim Position***
Power Purchases (excl Wind) and Transmission	Direct-Assigned to Export	Generation Allocated to Domestic & Dependable Exports	No position	Need to further consider the appropriateness of direct assignment of purchased power costs (other than wind) against exports, given the median water flow scenario used in the PCOSS.

[1] Unless noted, method was approved in PUB Order 116/08

Issue	***Last Approved by PUB (116/08)[1]***	***Manitoba Hydro PCOSS14-Amended***	***Bowman Pre-Filed Testimony***	***MIPUG Interim Position***
Trading Desk/MISO Fees	Direct-Assigned to Export	Generation Allocated to Domestic & Dependable Exports	No position	Need to consider relevance of Hydro's interim position (from PCOSS10 through PCOSS14 pre-Amendments) where 42% were allocated to exports directly and 58% to the common bulk power pooled costs.
Generation Allocation – Brandon Coal	50% of fixed costs and 100% of variable costs directly assigned to exports. Remainder to common pool	No direct assignment. Classify as per all other generation plant and allocate to Domestic & Dependable Exports	***No direct assignment.*** Classify as per all other generation plant and allocate to only Domestic	***As per Bowman***

Issue	***Last Approved by PUB (116/08)[1]***	***Manitoba Hydro PCOSS14-Amended***	***Bowman Pre-Filed Testimony***	***MIPUG Interim Position***
Generation Allocation – Brandon Gas	50% of fixed costs and 100% of variable costs directly assigned to exports. Remainder to common pool	No direct assignment. Classify and allocate as per all other generation plant	***No direct assignment.*** ***Classify and allocate as per all other generation plant*** (note however there is a difference on MIPUG vs MH view on how to allocate all other generation plant)	***As per Bowman***
Generation Allocation – Wind Purchases	Direct assigned to Exports	No direct assignment. Classify and allocate as per all other generation plant	***No direct assignment.*** Classify and allocate 100% to Energy (12PWE).	***As per Bowman***
DSM Cost Allocation	Costs Direct-Assigned to Export	Costs Direct-Assign to Domestic Classes	***Costs Direct-Assign to Domestic Classes***	***As per Bowman***

Issue	***Last Approved by PUB (116/08)***[1]	***Manitoba Hydro PCOSS14-Amended***	***Bowman Pre-Filed Testimony***	***MIPUG Interim Position***
Costs to be Allocated to the Export Cost (i.e., Number of Export Classes)	All Exports allocated a full share of fixed costs (one export class).	Dependable Exports allocated a share of fixed costs. Opportunity Exports only assigned variable costs. (two export classes)	All exports must share in the system fixed costs in some manner. (e.g., such as through one export class)	All exports must share in system fixed costs. At minimum this could be through implementing one export class with a full share of fixed costs allocated to all exports (dependable and opportunity). However, further consideration is needed on the potential for no export class, and all exports simply credited back to the relevant functions that support exports. This would materially simplify the COS study and reflect a principled linkage to the functions giving rise to the export revenue.

Issue	***Last Approved by PUB (116/08)[1]***	***Manitoba Hydro PCOSS14-Amended***	***Bowman Pre-Filed Testimony***	***MIPUG Interim Position***
Export Prices to be used to Establish Export Revenue in the PCOSS	Use Recent Actuals	Use IFF values	No position	***Use IFF values***
FROM EARLIER PUB DECISIONS				
Dorsey HVDC Functionalization	Transmission – Demand 2CP[2]	Generation – 12PWE	Transmission – Demand 2CP	As per Bowman

[2] Approved in Order 7/03 as part of the 2001 Status Update Filing review, however the PUB did note that Hydro should re-evaluate appropriateness of functionalization treatment of Dorsey Converter Station. But this was not commented on again in Order 117/06 (COSS Review) and or Order 116/08.

Similarly, power purchases, trading desk and MISO fees support all load under some conditions and Manitoba Hydro intends to assign these costs proportionately to all load.

The chart below provides a simplified view of the allocation of generation costs:

			Domestic	Dependable Export	Opportunity Export
Generation	Pool 1	Hydraulic Generation	✓	✓	✗
		Wind	✓	✓	✗
		Natural Gas Thermal	✓	✓	✗
		Coal Thermal	✓	✓	✗
Generation	Pool 2	Power Purchases & Transmission Fees	✓	✓	✓
		Water Rental & Variable Hydraulic O&M	✓	✓	✓
		Trading Desk	✓	✓	✓

7.1.4 Importance of a Reasonable Assignment of Cost to the Export Class

The objective of an Export Class in COS is to ensure fair cost responsibility for domestic customers. An over-assignment of cost to exports may:

- Equate to an under recognition of cost responsibility to some domestic customers,
- Result in the unit cost of exports to exceed that of GSL>100 kV (the most comparable Domestic class),
- Result in negative Net Export Revenue; and
- Effectively mute or unwind Manitoba Hydro's original rationale for adopting the Export Class, effectively returning to an allocation of export revenue on the basis of G&T costs.

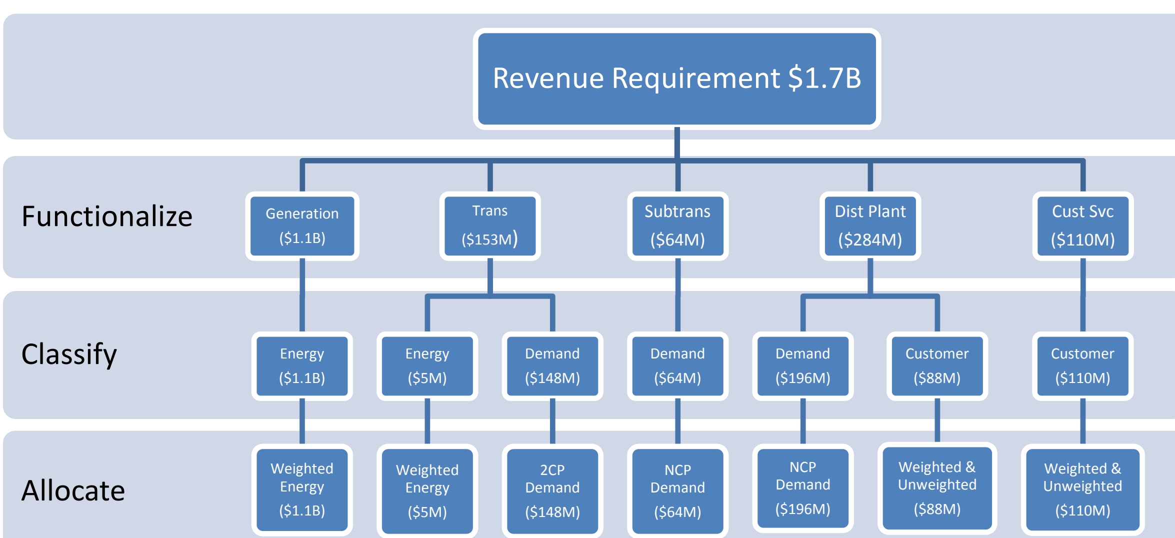
7.1.5 Allocation of Net Export Revenue

Manitoba Hydro agrees with CA that the allocation of Net Export Revenue on the basis of each class' total cost to serve is a reasonable perspective of fairness and will continue with this allocation approach for the following reasons:

- Energy-related costs are allocated based on consumption by each class. Manitoba Hydro uses a weighted energy allocator that recognizes a time-differentiated value of energy as well as customer usage patterns;
- Demand-related costs are allocated based on some measure of demand including the hourly consumption of each class measured at the time of the system peak (coincident peak) or each class' maximum hourly consumption regardless of when that occurs (non-coincident peak). Manitoba Hydro's measure of demand for Transmission investment is further refined to include the average of the winter and summer peaks (2CP) to recognize the dominant winter domestic peak and summer export-related peak; and
- Customer-related costs are allocated based on the number of customers in each class which can be weighted or un-weighted, depending on the cost category.

The allocation process also considers the use of facility by the rate class. For example, large industrial customers receiving service at the Transmission level do not use Subtransmission and Distribution facilities and therefore are not allocated a share of those costs.

Figure 5.0 below depicts how the overall Corporate Revenue Requirement flows through the COS process based on PCOSS14-Amended (IFF12) that reflects methodology changes as discussed in this Submission:



PUB Advisor Chart

Energy (kW.h) Weighted by Marginal Cost (Domestic, Dependable, and Opportunity Exports)

	2013/14 Forecast (kWh)	Weighted Energy/1000	Domestic/ Dependable Export Allocator	Domestic/ Total Export Allocator	Domestic-Only Allocator
Residential	8,659,590,963	29,836,159	29.0%	25.1%	34.7%
GS Small	4,229,802,467	14,626,606	14.2%	12.3%	17.0%
GS Medium	3,653,690,359	12,533,309	12.2%	10.6%	14.6%
GS Large	8,789,096,897	28,803,875	28.0%	24.3%	33.5%
Streetlights	117,520,773	301,949	0.3%	0.3%	0.4%
Total	25,449,701,458	86,101,897	83.8%	72.5%	100.0%
Dependable Exports	5,010,288,250	16,607,921	16.2%		
Opportunity Exports	9,834,000,000	32,597,385		27.5%	
Total Weighted Energy (Dependable Exports)		102,709,818			
Total Weighted Energy (Total Exports)		118,699,282			

Source: Daymark Model, PCOSS14-A Schedule D2 Corrected Weightings

Probabilistic Analysis
Updated Capital Costs – Keeyask and Conawapa

		Development Plan	1	2	4	8	5	14
			All Gas	K22/Gas	K19/Gas24 /250MW	CCGT/C26	K19/Gas25 /750MW	K19/C25 /750MW
							WPS Sale & Investment	
Energy Prices	Discount Rates	Capital Costs	Millions of 2014 NPV Dollars					
Low	Low	H	-1062	-1401	-851	-1501	-516	-1583
		Ref	-68	16	646	106	906	632
		L	734	1205	1898	1449	2086	2539
	Ref	H	-463	-1751	-1512	-2398	-1331	-3755
		Ref	208	-677	-334	-1085	-172	-1827
		L	750	232	658	15	795	-167
	High	H	-88	-1782	-1761	-2625	-1675	-4640
		Ref	416	-891	-748	-1480	-651	-2876
		L	823	-133	110	-519	205	-1356
Ref	Low	H	-2033	-120	543	325	236	2111
		Ref	-1039	1296	2040	1932	1658	4326
		L	-237	2486	3292	3275	2837	6233
	Ref	H	-671	-585	-260	-910	-492	-1130
		Ref	0	489	917	403	667	798
		L	542	1397	1910	1503	1634	2458
	High	H	17	-716	-620	-1343	-837	-2562
		Ref	520	175	393	-198	187	-798
		L	927	933	1251	762	1043	722
High	Low	H	-3454	892	1647	2005	645	5631
		Ref	-2460	2309	3143	3612	2066	7846
		L	-1658	3498	4396	4955	3246	9752
	Ref	H	-1158	402	797	469	112	1340
		Ref	-487	1476	1974	1782	1271	3268
		L	55	2384	2967	2882	2238	4928
	High	H	-82	210	368	-156	-186	-627
		Ref	422	1101	1381	989	837	1137
		L	828	1859	2239	1949	1694	2657

Figure 1: System Firm Winter Peak Demand and Capacity Resources (MW) @ generation

Fiscal Year		2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35
Power Resources																					
New Power Resources																					
New NUG PPA																					
Contracted																					
Proposed			9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
Total New NUG PPA			9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
1 **Total New Power Resources**			**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**	**9**
Base Supply Power Resources																					
Existing Hydro		5 172	5 164	5 166	5 171	5 286	5 811	5 802	5 797	5 797	5 797	5 797	5 797	5 797	5 797	5 797	5 797	5 797	5 797	5 797	5 797
Existing Thermal																					
Brandon Coal - Unit 5		105	105	105	105																
Selkirk Gas			66	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132	132
Brandon Units 6-7 SCGT		280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280	280
Contracted Imports		605	688	688	688	688	605	605	605	605	605	220	220	220	220	220					
Market Purchases																					
Additional Market Resources																					
Bipole III Reduced Losses					90	90	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
2 **Total Base Supply Power Resources**		**6 162**	**6 303**	**6 371**	**6 466**	**6 476**	**6 908**	**6 899**	**6 894**	**6 894**	**6 894**	**6 509**	**6 509**	**6 509**	**6 509**	**6 509**	**6 289**	**6 289**	**6 289**	**6 289**	**6 289**
3 **Total Power Resources**	1+2	**6 162**	**6 312**	**6 380**	**6 475**	**6 485**	**6 917**	**6 908**	**6 903**	**6 903**	**6 903**	**6 518**	**6 518**	**6 518**	**6 518**	**6 518**	**6 298**	**6 298**	**6 298**	**6 298**	**6 298**
Peak Demand																					
2015 Base Load Forecast		4 829	4 936	5 000	5 063	5 086	5 210	5 267	5 337	5 406	5 476	5 547	5 619	5 692	5 765	5 840	5 915	6 012	6 112	6 220	6 341
Less: 2015 DSM Forecast		- 46	- 89	- 195	- 280	- 369	- 456	- 542	- 585	- 621	- 654	- 685	- 719	- 753	- 788	- 824	- 831	- 837	- 843	- 849	- 854
4 **Manitoba Net Load**		4 783	4 847	4 805	4 783	4 717	4 754	4 725	4 752	4 785	4 822	4 862	4 900	4 939	4 977	5 016	5 084	5 175	5 269	5 371	5 487
Contracted Exports		572	789	789	614	614	779	908	880	880	880	385	385	275	275	275	275	275	275	275	275
Proposed Exports							110	110	110	110	110	110	110	110	110	110	110	110	110	110	110
5 **Total Exports**		572	789	789	614	614	889	1 018	990	990	990	495	495	385	385	385	385	385	385	385	385
6 **Total Peak Demand**	4+5	**5 355**	**5 636**	**5 594**	**5 397**	**5 331**	**5 643**	**5 743**	**5 742**	**5 775**	**5 812**	**5 357**	**5 395**	**5 324**	**5 362**	**5 401**	**5 469**	**5 560**	**5 654**	**5 756**	**5 872**
7 Reserves		574	582	577	574	566	571	567	570	574	579	583	588	593	597	602	610	621	632	645	658
System Surplus	3-6-7	**233**	**94**	**209**	**504**	**588**	**703**	**598**	**591**	**554**	**512**	**578**	**535**	**601**	**559**	**515**	**219**	**117**	**12**	**- 103**	**- 232**

Figure 2: System Firm Energy Demand and Dependable Resources (GWh) @ generation

Fiscal Year		2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35
Power Resources																					
New Power Resources																					
New Nug PPA																					
Contracted																					
Proposed			48	97	97	97	97	97	97	97	97	97	97	97	97	97	97	97	97	97	97
Total New Nug PPA			**48**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**
1 **Total New Power Resources**			**48**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**	**97**
Base Supply Power Resources																					
Existing Hydro		21 924	21 892	21 878	21 880	22 356	24 790	24 778	24 746	24 746	24 736	24 726	24 726	24 716	24 706	24 706	24 696	24 696	24 686	24 676	24 676
Existing Thermal																					
Brandon Coal - Unit 5		811	811	811	811	592															
Selkirk Gas		953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953	953
Brandon Units 6-7 SCGT		2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354	2 354
Contracted Imports		2 485	2 809	2 809	2 809	2 809	3 502	3 688	3 688	3 688	3 688	2 321	2 050	2 050	2 050	2 050	1 268	1 113	1 113	1 113	1 113
Proposed Imports																					
Hydro Adjustment		784	903	903	903	903	844	844	844	844	844	406	307	307	307	307	70				
Market Purchases		582	258	258	258	258	957	1 050	1 050	1 050	1 050	2 417	2 688	2 688	2 688	2 688	3 440	3 624	3 624	3 625	3 625
Additional Market Resources																					
Existing Wind		771	771	771	771	771	771	771	771	771	771	771	771	771	771	771	771	771	771	771	771
Bipole III Reduced Losses					101	101	177	177	177	177	177	177	177	177	177	177	177	177	177	177	177
2 **Total Base Supply Power Resources**		**30 664**	**30 751**	**30 737**	**30 840**	**31 097**	**34 348**	**34 615**	**34 583**	**34 583**	**34 573**	**34 125**	**34 026**	**34 016**	**34 006**	**34 006**	**33 729**	**33 688**	**33 678**	**33 669**	**33 669**
3 **Total Power Resources**	1+2	**30 664**	**30 799**	**30 834**	**30 937**	**31 194**	**34 445**	**34 712**	**34 680**	**34 680**	**34 670**	**34 221**	**34 122**	**34 112**	**34 102**	**34 102**	**33 826**	**33 785**	**33 775**	**33 766**	**33 766**
Manitoba Domestic Load																					
2015 Base Load Forecast		26 145	26 792	27 126	27 486	27 600	28 449	28 786	29 197	29 590	29 999	30 408	30 823	31 243	31 664	32 094	32 531	33 101	33 684	34 317	35 011
Non-Committed Construction Power		110	110	110	110	110	83														
Less: 2015 DSM Forecast		- 217	- 412	- 852	-1 231	-1 652	-1 940	-2 231	-2 399	-2 557	-2 704	-2 844	-2 995	-3 156	-3 325	-3 498	-3 534	-3 566	-3 598	-3 628	-3 655
4 **Manitoba Net Load**		**26 038**	**26 490**	**26 384**	**26 365**	**26 058**	**26 592**	**26 555**	**26 798**	**27 033**	**27 295**	**27 564**	**27 828**	**28 087**	**28 339**	**28 596**	**28 997**	**29 535**	**30 086**	**30 689**	**31 356**
Contracted Exports		2 739	3 388	3 502	3 289	3 246	3 964	4 604	4 503	4 476	4 476	2 193	2 049	1 634	1 551	1 551	1 389	1 389	1 389	1 389	1 389
Proposed Exports							459	551	551	551	551	551	551	551	551	551	551	551	551	551	551
Less: Adverse Water		- 309	- 370	- 370	- 370	- 370	- 370	- 489	- 512	- 512	- 512	- 85									
5 **Total Net Exports**		**2 430**	**3 018**	**3 132**	**2 919**	**2 876**	**4 053**	**4 666**	**4 542**	**4 515**	**4 515**	**2 659**	**2 600**	**2 185**	**2 102**	**2 102**	**1 940**	**1 940**	**1 940**	**1 940**	**1 940**
6 **Total Energy Demand**	4+5	**28 468**	**29 508**	**29 516**	**29 284**	**28 934**	**30 645**	**31 221**	**31 340**	**31 548**	**31 810**	**30 223**	**30 428**	**30 272**	**30 441**	**30 698**	**30 937**	**31 475**	**32 026**	**32 629**	**33 296**
System Surplus	3-6	**2 197**	**1 291**	**1 318**	**1 653**	**2 260**	**3 800**	**3 491**	**3 340**	**3 132**	**2 860**	**3 998**	**3 694**	**3 840**	**3 661**	**3 404**	**2 889**	**2 310**	**1 749**	**1 137**	**470**

	PCOSS14 116/08	PCOSS14	PCOSS14 Amended
	($ Million)	($ Million)	($ Million)
Gross Export Revenue	340*	345	345
Less:			
Purchased Power excl Wind (Note 1)	106	90	25
Purchased Power - Wind (Note 2)	65	10	10
Natural Gas Thermal (Note 2)	17	5	5
Coal Thermal Costs (Note 3)	16	n/a	5
Trading Desk (Note 1)	13	5	4
DSM	40	n/a	n/a
Generation (remaining cost including Hydro, Water Rentals and Variable O&M)	160	132	146
MISO Fees (Note 4)	4	2	1
Transmission	30	29	21
NEB	1	1	1
Policy Related Charges (AER & URA)	36	36	36
Net Export Revenue	(147)	34	91

* Order 116/08 directed Manitoba Hydro to recalculate Gross Export Revenue using the most recent actual export prices. Average export prices in 2012/13 were slightly less than the average forecast price underlying the export revenues for 2013/4, resulting in the $5 million decrease in Gross Export Revenues.

Note 1 – costs were directly assigned to exports in PCOSS14 (Order 116/08) and PCOSS14, and allocated as part of the generation pool in PCOSS14-Amended

Note 2 – costs were directly assigned to exports in PCOSS14 (Order 116/08), and allocated as part of the generation pool in PCOSS14 and PCOSS14-Amended

Note 3 - costs were directly assigned to exports in PCOSS14 (Order 116/08), and allocated as part of the generation pool in PCOSS14-Amended.

Note 4 – costs were directly assigned to exports in PCOSS14 (Order 116/08) and PCOSS14, and allocated on the basis of 2CP Demand in PCOSS14-Amended.

<u>Downstream Functions:</u>

Transmission

Transmission costs include the capital and operating costs of Centra's high-pressure Transmission system, plus the cost of Unaccounted for Gas ("UFG") that occurs on Centra's Transmission and Distribution system. All UFG costs are allocated to the Transmission function for cost allocation purposes, in order to ensure that all customer classes are allocated their appropriate share of the UFG costs regardless of whether they are served from Centra's Transmission or Distribution system.

Distribution

Distribution costs include the capital and operating costs of Centra's high, medium, and low-pressure Distribution systems.

Onsite

Onsite costs include capital and operating costs of Centra's investment in service lines, meters, and other equipment installed on customers' premises, plus the costs of customer accounting and customer service.

11.2.2 Classifying Costs

The second step in the process is to "classify" the costs that have been functionalized. The classification process amounts to identifying the basis of the variability of the costs. For a gas utility, the variability of costs is usually classified according to the following three factors:

Section:	Tab 4 Appendix 4.1	Page No.:	CEF 14 Pg. 3
Topic:	Capital Expenditure Forecast		
Subtopic:	HVDC – System Capabilities		
Issue:	Bipole I,II & III Utilization		

PREAMBLE TO IR (IF ANY):

NFAT PUB/MH I-042(a) Revised calculates the current and future energy usage of the Bipole system.

QUESTION:

Refile NFAT IR PUB/MH I-042 (a) Revised adding to each table the online percentage capacity utilization of total hydraulic generation and percentage capacity utilization of the total HVDC transmission system.

RATIONALE FOR QUESTION:

This IR explores the future usage of the Bipole system.

RESPONSE:

The following provides a reposting of tables from NFAT IR PUB/MH I-042(a) with online percentage capacity utilization of total existing and committed generation and percentage capacity utilization of the total HVDC transmission system.

Bipoles I and II – 2013						HVDC Losses (GWh)						
Generating Station	MW	Depend (GWh)	Median GWh	Max GWh	Utiliz	Maximum HVDC Limit		Capacity	Spare	Utiliz	Depend	Mean
Kettle	1220	4750	7010	8960	100%	Bipole I	14140 GW.h	1854 MW	309 MW	83%	480	850
Long Spruce	1010	3890	5970	7830	100%							
Limestone	1340	5140	7500	9900	100%	Bipole II	15260 GW.h	2000 MW	500 MW	75%	480	850
Total	3570	13780	20480	26690	100%	Total	29400 GW.h	3854 MW	500 MW	87%	960	1700

After Bipole III – 2019 without Keeyask						HVDC Losses (GWh)						
Generating Station	MW	Depend (GWh)	Median GWh	Max GWh	Utiliz	Maximum HVDC Limit		Capacity	Spare	Utiliz	Depend	Mean
						Bipole I	12540 GW.h	1854 MW	309 MW	83%	250	440
Kettle	1220	4750	7010	8960	100%							
Long Spruce	1010	3890	5970	7830	100%	Bipole II	13520 GW.h	2000 MW	500 MW	75%	250	440
Limestone	1340	5140	7500	9900	100%							
						Bipole III	13520 GW.h	2000 MW	500 MW	75%	250	440
Total	3570	13780	20480	26690	100%	Limit	41610 GW.h	5854 MW	1104 MW	81%	750	1320

After Bipole III – 2022 with Keeyask						HVDC Losses (GWh)						
Generating Station	MW	Depend (GWh)	Median GWh	Max GWh	Utiliz	Maximum HVDC Limit		Capacity	Spare	Utiliz	Depend	Mean
Keeyask	630	3000	4400	4740	100%	Bipole I	12540 GW.h	1854 MW	309 MW	83%	310	550
Kettle	1220	4750	7010	8960	100%							
Long Spruce	1010	3890	5970	7830	100%	Bipole II	13520 GW.h	2000 MW	500 MW	75%	310	550
Limestone	1340	5140	7500	9900	100%							
						Bipole III	13520 GW.h	2000 MW	500 MW	75%	310	550
Total	4200	16780	24880	31430	100%	Limit	41610 GW.h	5854 MW	1104 MW	81%	930	1650

Section:	Tab 4 Appendix 4.1	**Page No.:**	CEF 14 Pg. 3
Topic:	Capital Expenditure Forecast		
Subtopic:	HVDC – System Capabilities		
Issue:	Bipole I,II & III Utilization		

PREAMBLE TO IR (IF ANY):

NFAT PUB/MH I-042(a) Revised calculates the current and future energy usage of the Bipole system.

QUESTION:

Explain why the addition of Conawapa G.S. in 2029 would reduce the maximum HVDC limit from 48,900 GWh to 46,270 GWh.

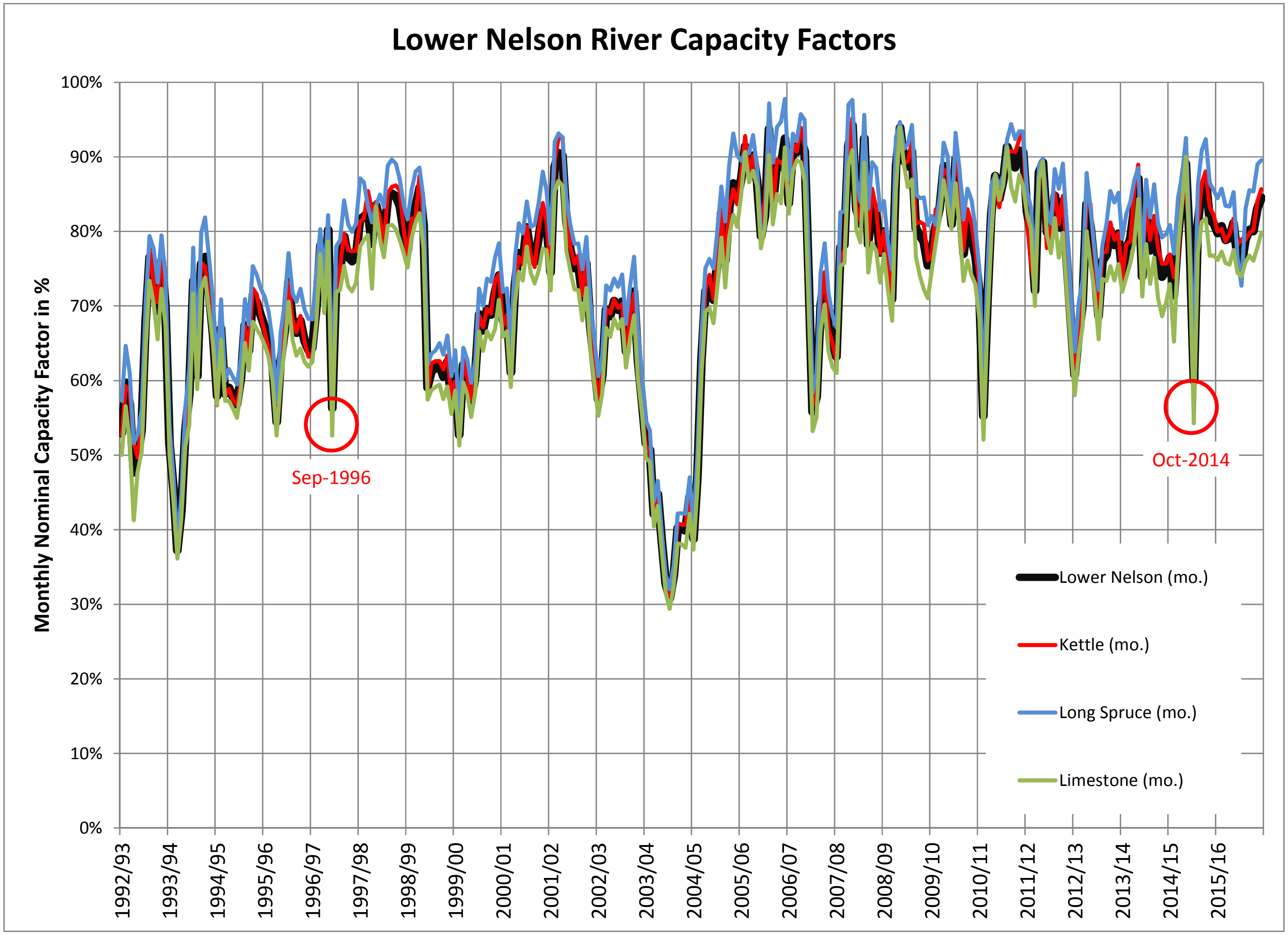
RATIONALE FOR QUESTION:

This IR explores the future usage of the Bipole system.

RESPONSE:

The maximum HVDC limit of 48900 GWh reported in NFAT PUB/MH I-042(a) Revised is an unobtainable maximum. The maximum should have been reported as 41600 GWhs which reflects a maximum HVDC loading of 4750MW. Having a single, close coupled HVDC system is limited to a maximum of 4750 MW allowable single point injection into the southern AC system. Having more than 4750 MW of generation on the lower Nelson requires splitting the HVDC system into two, electrically independent systems to ensure that neither system is greater than 4750 MW. The net result of splitting the HVDC system is an increase in maximum overall limit to 5279 MW (46270 GW.h).

Figure 2. Monthly capacity factors for Lower Nelson River stations from 1992/93 through 2015/16.



Section:	Main Filing Document	Page No.:	21 of 23
Topic:	US Interconnections		
Subtopic:	Allocation of costs associated with the US Interconnections		
Issue:	Size of US Interconnection		

PREAMBLE TO IR (IF ANY):

Regarding the purpose of the investment in US Interconnections:

QUESTION:

a) Please provide a table of each major capital investment Manitoba Hydro has made to expand US Interconnection capacity. In this table please also list the in-service date of each project and total dollars invested in the project.

b) Please describe in detail the economic or reliability basis for each of the major investments made by Manitoba Hydro listed in part (a).

RATIONALE FOR QUESTION:

Appropriateness of the allocation of the costs of US interconnection.

RESPONSE:

The following table provides the major transmission interconnection investments undertaken by Manitoba Hydro since 1970 along with the rationale, and net book value of the investments to the extent available. As depicted in the table, these investments were undertaken to provide both reliable and low cost power to Manitobans. The interconnections facilitate the exchange of power between Manitoba Hydro, a winter peaking utility, and the U.S. which is summer peaking. The 500 kV line also provides an important access to power for Manitoba in the event the HVDC lines are lost.

Date	Project Name	Original Total Length (km)	Total Length of Interconnection Today (km)	2014 NBV ($ millions)	Max Export Capability at MH-US border	Max Import Capability at MH-US border	History Notes	Reason for Project
1970	L20D: Letellier (MB) to Drayton (ND)	232	61.7	$ 3.0	330	100	Line originally terminated between Winnipeg (LaVerendrye) and Grand Forks (Prairie). Letellier was constructed around 1977.	Construction of Grand Rapids (1965-1968). Agreement to exchange power with NSP, OTP and MPC. 90 MW of winter capacity purchased in 1970 rather than add another thermal plant at Selkirk.
1976	R50M: Richer (MB) to Moranville (MN)	186.8	123.5	$ 1.5	550	300	Line originally went from Ridgeway to Shannon with tap at Moranville.	Construction of Kettle (1974). Agreement to export firm and interruptible power to MP and MPC.
1980	M602F: Riel (MB) to Forbes (MN)	537.3	487.5	$ 31.3	1425	700	Line originally went from Dorsey to Forbes. Riel station added in 2014.	Long Spruce (1979). Addition of line more than doubled ability to exchange power with the US. The line allowed for a major sale of surplus power to NSP. Seasonal diversity was used to help provide economic justification for the line. The line was also recognized to improve reliability in case MH lost the HVDC.
1993	Manitoba Minnesota Phase 1, 500 kV Series Compensation (MN) and Dorsey station upgrades (MB)			see Note 1	1625	500	Added series capacitors to 500 kV line in the US. Added extra 230/500 kV transformer and shunt caps at Dorsey.	Capacity increase needed to provide a 400 MW increase in transfer capability. The driver was a 1989 diversity exchange agreement between MH and NSP and UPA that covered the period 1995 to 2014. MH would export an additional 400 MW to the US in the summer and import 400 MW in the winter.
1994	Manitoba Minnesota Phase 2, Static Var Compensator at Forbes (MN)			N/A – see Note 2	1800	500	Added SVC at Forbes station in US	Part of 1989 diversity exchange facility additions
1996	Manitoba Minnesota Phase 3, 230 kV shunt capacitors (MN)			N/A – see Note 2	1975	500	Addition of capacitors at several locations including Running, New Roseau County substation near R50M and Prairie near L20D.	Part of 1989 diversity exchange facility additions
2002	G82P: Glenboro (MB) to Peace Garden (ND)	170.9	83.3	$ 15.9	2175	700	Peace Garden station added in 2015	Limestone (1991). Line built primarily to firm up import capability to meet NSP's obligation of 500 MW but it also improved export capability. Surplus power from Limestone was exported to NSP over all US interconnections.

Note 1: these costs are included in the Dorsey 500 kV AC Switchyard which has a 2014 NBV of $32.8 million.

Note 2: these projects were undertaken by a US utility on the US side of the border but resulted in increased export capability for Manitoba Hydro.

Section:	Tab 3: Appendix 3.3	**Page No.:**	Section 5
Topic:	Integrated Financial Forecast & Economic Outlook		
Subtopic:	Export Contracts		
Issue:	Updated Contract Commitments		

PREAMBLE TO IR (IF ANY):

NFAT Exhibit # MH-100 sets out the contract sales, contracted surplus energy sales and non-contracted energy sales.

QUESTION:

Provide an updated NFAT Exhibit MH-100 with additional columns to reflect current contract status.

RATIONALE FOR QUESTION:

Export contract revenues are only aggregated in IFF14.

RESPONSE:

Updated NFAT Exhibit MH-100 is included in the tables below including contract status.

Table #1 MH Export Contracts After 2015 – Dependable Capacity & Energy

Customer	Contract Name	Status	Capacity (MW)	Energy Product	Capacity Revenue	Energy Revenue	Total Revenue (Expense)
Minnesota Power	MP 250	Signed	250	5x16			
	MP Energy Exchange	Signed	0				
	MP 50	Signed	50	5x16			
	MP 133	Signed	0				
Northern States Power	NSP125	Signed	125	5x16(S) 5x12(W)			
	NSP 375/325 SPS	Signed	375(S) 325(W)	5x16(S) 5x12(W)			
	NSP 350 Div. Exchge	Signed	350	7x4 (S)			
Wisconsin Public Service	WPS 100 Product A	Signed	100	5x16			
	WPS 100 Product B	Signed	0				
	WPS 108	Signed	108	5x16			
	WPS 308	Signed	308	5x16			
Great River Energy	GRE Div. Exchange	Signed	200	7x4 (S)			
SaskPower	SaskPower 25	Signed	25	5x16			
Total					$1,239M	$4,536M	$5,776M

Table #2 MH Export Contracts After 2015 – Contracted Surplus Energy

Customer	Contract Name	Status	Surplus Energy Product	Energy Revenue
Minnesota Power	MP 250	Signed	2x16	
	MP Energy Exchange	Signed		
	MP 50	Signed	2x16	
	MP 133	Signed		
Northern States Power	NSP125	Signed		
	NSP 375/325 SPS	Signed		
	NSP 350 Div.Exchge	Signed		
Wisconsin Public Service	WPS 100 Product A	Signed	2x16	
	WPS 100 Product B	Signed		
	WPS 108	Signed		
	WPS 308	Signed	2x16	
Great River Energy	GRE Div. Exchange	Signed		
SaskPower	SaskPower 25	Signed	2x16	
Total				$971M

Table #3 MH Export Contracts After 2015 – Non-Contracted Surplus Energy Sales

Customer	Contract Name	Status	Surplus Energy Product	Energy Revenue
Minnesota Power	MP 250	Signed	*7x8*	
	MP Energy Exchange	Signed		
	MP 50	Signed	7x8	
	MP 133	Signed		
Northern States Power	NSP125	Signed	5x4 (W) 2x16 7x8	
	NSP 375/325 SPS	Signed	5x4 (W) 2x16 7x8	
	NSP 350 Div. Exchge	Signed	All but 7x4 (S)	
Wisconsin Public Service	WPS 100 Product A	Signed	7x8	
	WPS 100 Product B	Signed		
	WPS 108	Signed	2x16 7x8	
	WPS 308	Signed	7x8	
Great River Energy	GRE Div. Exchange	Signed	All but 7x4 (S)	
SaskPower	SaskPower 25	Signed		
Total				$3,463M

Table #4 MH Export Contracts After 2015 – Total Revenue

Customer	Contract Name	Status	Capacity Revenue	Energy Revenue	Total Revenue
Minnesota Power	MP 250	Signed			
	MP Energy Exchange	Signed			
	MP 50	Signed			
	MP 133	Signed			
Northern States Power	NSP125	Signed			
	NSP 375/325 SPS	Signed			
	NSP 350 Div. Exchge	Signed			
Wisconsin Public Service	WPS 100 Product A	Signed			
	WPS 100 Product B	Signed			
	WPS 108	Signed			
	WPS 308	Signed			
Great River Energy	GRE Div. Exchange	Signed			
SaskPower	SaskPower 25	Signed			
Total			$1,239M	$8,970M	$10,122M

Section:	Appendix 3 PCOSS 14	**Page No.:**	
Topic:	Marginal Costs		
Subtopic:	Marginal Energy Weighting		
Issue:	12 SEP Weighting		

PREAMBLE TO IR (IF ANY):

Current 12 SEP data used for weighting energy currently employs pre 2008/09 data.

QUESTION:

a) Please provide Manitoba Hydro's forecasted marginal values for generation and transmission by season and time period (peak, off-peak, shoulder). If required, the response can be filed in confidence.

b) Please provide the Surplus Energy Program prices for each of the 12 periods and for each of the years that are used in the calculation of the proxy prices used for calculating the energy weightings in PCOSS14 (in Excel format).

c) If different SEP prices are used in the calculation of proxy prices for calculating the energy weightings in PCOSS14 Amended compared to PCOSS14, please file the corresponding data for PCOSS14 Amended as filed in (b) (in Excel format).

d) Please make a comparison table showing the forecasted marginal values in (a) and the SEP-based proxy prices in (b) and (c) by period and show the variances.

e) Please file SEP-based proxy prices and supporting calculations for the energy weightings based on the use of only post-2008/09 SEP data.

RATIONALE FOR QUESTION:

To understand the impact of using more current information in the weighting of energy and capacity for establishing the allocation of energy and demand costs.

RESPONSE:

a) Manitoba Hydro does not prepare forecasted short run marginal values for the Surplus Energy Program (SEP) for the upcoming season and hence cannot provide the requested information.

The SEP Program is a revenue neutral program that offers customers choice and access to surplus energy at prices that reflect Manitoba Hydro's short term marginal cost of energy. Each Wednesday Manitoba Hydro applies to the Public Utilities Board for interim ex parte approval of the SEP Energy Rates to be in effect the following Monday through Sunday.

Each week, Manitoba Hydro does forecast short run marginal values for the Surplus Energy Program for the upcoming week, and these forecasts are filed immediately with the Public Utilities Board. Beyond the upcoming week, SEP short run marginal values are subject to near term weather variations and other uncertainties which make forecasting more difficult and less useful. The weather variations will tend to average out over multi-year periods.

b) Please see the Excel model titled 'Derivation of Energy Weights for PCOSS14.xlsx', provided on March 11, 2016.

c) The same SEP prices were used for PCOSS14 and PCOSS14-Amended.

d) As indicated in the response to part a), Manitoba Hydro does not prepare forecasts for SEP prices beyond the current week and is therefore unable to make the requested comparison of forecast to actual values.

e) The weightings used in PCOSS14 were based on eight years of SEP prices from April 1, 2004 to March 31, 2012. The model, noted above, was updated to include only SEP prices from April 1, 2009 to March 31, 2012, yielding updated weightings as follows:

	Marginal Cost Weighting		
	Peak	**Shoulder**	**Off**
Spring Season:	2.943	2.563	1.519
Summer Season:	3.588	2.424	1.000
Fall Season:	3.057	2.443	1.324
Winter Season:	3.897	2.885	2.154

Comparison of SEP Weightings for Weighted Energy Allocator

Weightings based on Marginal Cost (MC) derived from Surplus Energy Program prices

PCOSS14-Amended: SEP prices from 2004 to 2012

Without Capacity Adder

MC Weighting 2004-12	Peak	Shoulder	Off
Spring	3.657	3.043	1.739
Summer	4.556	3.011	1.000
Fall	3.860	3.059	1.717
Winter	4.658	3.329	2.503

With Capacity Adder of 1.31 to Peak Periods

MC Weighting 2004-12	Peak	Shoulder	Off
Spring	4.967	3.043	1.739
Summer	5.866	3.011	1.000
Fall	5.170	3.059	1.717
Winter	5.968	3.329	2.503

SEP Prices from 2009 to 2012 per PUB/MH-1f

MC Weighting 2009-12 w/o capacity adder	Peak	Shoulder	Off
Spring	2.943	2.563	1.519
Summer	3.588	2.424	1.000
Fall	3.057	2.443	1.324
Winter	3.897	2.885	2.154

MC Weighting 2009-12 w/ capacity adder	Peak	Shoulder	Off
Spring	4.253	2.563	1.519
Summer	4.898	2.424	1.000
Fall	4.367	2.443	1.324
Winter	5.207	2.885	2.154

Comparison - 2009-12 vs 2004-12

	Peak	Shoulder	Off
Spring	(0.714)	(0.480)	(0.220)
Summer	(0.968)	(0.587)	-
Fall	(0.803)	(0.616)	(0.393)
Winter	(0.761)	(0.444)	(0.349)

Comparison - Difference Peak to Off-Peak

	Peak to Off 2004-12	Peak to Off 2009-12
Spring	3.228	2.734
Summer	4.866	3.898
Fall	3.453	3.043
Winter	3.465	3.053

PUB Advisor Table

Sources: PUB/MH-1 and "Derivation of Energy Weights for PCOSS14.xls", MH FTP site position advocated for by any party in this proceeding or consistent in any manner with regulatory decisions in this province.

1.1.2 NET EXPORT REVENUE

Hydro's rebuttal analysis on Net Export Revenue is not inconsistent in any way with the material in Bowman Undertaking #32, in regard to the net effect of calculating Revenue:Cost Coverage (RCC) Ratios in the near-term. Hydro's analysis however uses PCOSS14-Amended, which has been designed to ensure that almost all classes are within the 95%-105% zone of reasonableness. In that environment, the net impact of any decision to not include the NER in the Cost of Service study is small.

The response to Undertaking #32 however shows the impact of removing the NER from consideration in the Cost of Service study when using the recommended COS methods, such as a single export class and other proposals from the Bowman Pre-Filed Testimony. This table is repeated below for clarity:

Table 1: Table 2 from MIPUG Undertaking #32: RCC Ratios before NER and Surplus/shortfall balances reflecting Bowman Pre-Filed Testimony

Customer Class	Total Cost ($000)	Class Revenue ($000)	Revenue:Cost	Surplus/(Shortfall)
Residential	619,285	567,599	91.7%	(51,686)
General Service - Small Non Demand	127,685	133,251	104.4%	5,567
General Service - Small Demand	131,172	135,647	103.4%	4,475
General Service - Medium	187,075	186,756	99.8%	(319)
General Service - Large 0 - 30kV	91,775	84,956	92.6%	(6,819)
General Service - Large 30-100kV*	55,398	57,808	104.3%	2,410
General Service - Large >100kV*	179,694	189,258	105.3%	9,563
Area & Roadway Lighting	21,937	21,386	97.5%	(551)
Total General Consumers - Rate Setting	**1,414,021**	**1,376,660**	**97.4%**	(37,361)

Table 1 above shows that under this set of COS methods consistent with past Board Orders and with the Bowman Pre-Filed Testimony, the NER credited back to the domestic interconnected customer classes is $37.361 million (i.e., domestic interconnected classes are only paying 97.4% of the costs allocated to them). The table also shows that before any allocation of NER, four of the eight classes are already being charged rates that exceed their full share of costs, and the remaining four are receiving all of the benefit of all of the NER, plus the benefit of the added revenues from the four classes that are overpaying. The best outcome to address this situation is above average increases starting with those classes below 95% RCC (particularly Residential and GSL 0-30 kV), and then bringing all classes ultimately to 100%, reaching a point where the NER is no longer serving to offset a portion of today's costs. At that time discussions can occur about the best way to benefit ratepayers via the use of the now-surplus NER (preferably

STUDY	**PCOSS06**	**PCOSS06** [Note 1]	**PCOSS08**	**PCOSS10** [Note 2]	**PCOSS13**	**PCOSS14**	**PCOSS14**
VERSION	**Recommended Methodology**	**Response Order 117/06**	**Response to Order 116/08**		**With Methodology Changes**		**Amended**
DATE	**September 2005**	**April 12, 2007**	**Mar 3, 2009**	**Nov 30, 2009**	**July 2012**	**June 2013**	**December 2015**
DESCRIPTION	MH's recommended method which reflects recommendations from NERA report	Reflects Order 117/06	Reflects Orders 116/08 and 117/06	Reflects 116/08 with modifications	Reflects recommendations from 2012 Christensen and Associates' review of COS methodology	Reflects recommendations from 2012 Christensen and Associates' review of COS methodology	Reflects recommendations from 2015 Christensen and Associates' Supplemental review, discussions at 2014 Stakeholder sessions, and further reconsideration by MH

EXPORT CLASS							
Export Differentiation	Recognizes cost differences of export sales and differentiates between Dependable and Opportunity exports	Does not recognize cost distinction between export sales types	Does not recognize cost distinction between export sales types	Does not recognize cost distinction between export sales types	Recognizes cost differences of export sales and differentiates between Dependable and Opportunity exports	Recognizes cost differences of export sales and differentiates between Dependable and Opportunity exports	Recognizes cost differences of export sales and differentiates between Dependable and Opportunity exports
Export Assumptions	•45% of Power Purchases and Brandon Thermal assumed to serve Opportunity, unserved Opportunity receive Water Rentals only •Dependable served from Generation Pool	•Exports not served by DSM, Power Purchases or Thermal are served out of the Generation Pool	•Exports not served by Power Purchases or Thermal are served out of the Generation Pool •DSM energy savings not assumed to serve export load, instead are added to domestic load	•Exports not served by Power Purchases/Wind or Brandon GS are served from Generation Pool	•Opportunity not served by Power Purchases (excl wind), attract Water Rentals and Variable Hydraulic O&M only •Dependable served from Generation Pool	•Opportunity not served by Power Purchases (excl wind), attract Water Rentals and Variable Hydraulic O&M only •Dependable served from Generation Pool	•Domestic, Dependable and Opportunity exports share Power Purchases (excl Wind), Water Rental Fees and Variable Hydraulic O&M •Dependable served from Generation Pool
Basis of Export Revenue	As forecast in IFF	As forecast in IFF	Recalculated to use most recent actual prices	As forecast in IFF	As forecast in IFF	As forecast in IFF	As forecast in IFF

EXPORT COST ASSIGNMENT							
DSM Costs	Domestic Direct (based on class participation)	Exports (w/energy reduction)	Export Direct (no energy reduction)	Domestic Direct (based on class participation)	Domestic Direct (based on class participation)	Domestic Direct (based on class participation)	Domestic Direct (based on class participation)
Affordable Energy Fund (AEF) Expenditures	n/a	Export Direct	Export Direct	Export Direct	Export Direct	Export Direct	Export Direct
Trading Desk	Domestic/Depend Export Pool	Export Direct	Export Direct	42% Export Direct 58% Domestic Pool	42% Export Direct 58% Domestic Pool	42% Export Direct 58% Domestic Pool	Domestic/Export Pool
Purchased Power & Transmission (excl wind)	45% Opportunity Export Direct 55% Domestic/Depend Export Pool	Export Direct	Export Direct	Export Direct	Opportunity Export Direct	Opportunity Export Direct	Domestic/Export Pool
MISO Fees	45% Opportunity Export Direct 55% Domestic/Depend Export Pool	Export Direct	Export Direct	42% Export Direct 58% Domestic Pool	42% Export Direct 58% Domestic Pool	42% Export Direct 58% Domestic Pool	Domestic/Export Pool
Water Rentals & Variable Hydraulic O&M	Unserved Opportunity Direct Remaining Costs: Domestic/Depend Export Pool	Domestic/Unserved Export Pool	Domestic/Unserved Export Pool	Domestic/Unserved Export Pool	Unserved Opportunity Direct Remaining Costs: Domestic/Depend Export Pool	Unserved Opportunity Direct Remaining Costs: Domestic/Depend Export Pool	Domestic/Export Pool
Wind Purchases	45% Opportunity Export Direct 55% Domestic/Depend Export Pool	Export Direct	Export Direct	Export Direct	Domestic/Depend Export Pool	Domestic/Depend Export Pool	Domestic/Depend Export Pool
Selkirk GS Fuel	Domestic/Depend Export Pool	Export Direct	Export Direct	Domestic Pool	Domestic/Depend Export Pool	Domestic/Depend Export Pool	Domestic/Depend Export Pool
Selkirk GS All Other	Domestic/Depend Export Pool	Domestic/Unserved Export Pool	50% Export Direct 50% Domestic Pool	Domestic Pool	Domestic/Depend Export Pool	Domestic/Depend Export Pool	Domestic/Depend Export Pool
Brandon CT Fuel	45% Opportunity Export Direct 55% Domestic/Depend Export Pool	Export Direct	Export Direct	Domestic Pool	Domestic/Depend Export Pool	Domestic/Depend Export Pool	Domestic/Depend Export Pool
Brandon CT All Other	Domestic/Depend Export Pool	Domestic/Unserved Export Pool	50% Export Direct 50% Domestic Pool	Domestic Pool	Domestic/Depend Export Pool	Domestic/Depend Export Pool	Domestic/Depend Export Pool
Brandon GS Fuel	45% Opportunity Export Direct 55% Domestic/Depend Export Pool	Export Direct	Export Direct	Export Direct (also incl Variable O&M costs)	Domestic Pool	Domestic Pool	Domestic/Depend Export Pool
Brandon GS All Other	Domestic/Depend Export Pool	Domestic/Unserved Export Pool	50% Export Direct 50% Domestic Pool	Domestic Pool	Domestic Pool	Domestic Pool	Domestic/Depend Export Pool
Balance of Generation Costs	Domestic/Depend Export Pool	Domestic/Unserved Export Pool	Domestic/Unserved Export Pool	Domestic/Unserved Export Pool	Domestic/Depend Export Pool	Domestic/Depend Export Pool	Domestic/Depend Export Pool
Balance of Transmission Costs	Domestic/Depend Export Pool	Domestic/Export Pool	Domestic/Export Pool	Domestic/Export Pool	Domestic/Depend Export Pool	Domestic/Depend Export Pool	Domestic/Depend Export Pool

GENERATION AND TRANSMISSION							
Generation Allocator	4 period marginal cost Weighted Energy (CRP Credit on 2CP Demand)	12 period marginal cost Weighted Energy	12 period marginal cost Weighted Energy	12 period marginal cost Weighted Energy	12 period marginal cost Weighted Energy	12 period marginal cost Weighted Energy	12 period marginal cost Weighted Energy incl value of capacity
Dorsey Converter Facilities Functionalization	100% Transmission	100% Transmission	100% Transmission	100% Transmission	100% Transmission	100% Transmission	100% Generation
Radial Transmission Functionalization	Transmission lines not eligible for the OATT, including radial transmission, functionalized as Subtransmission	Transmission lines not eligible for the OATT, including radial transmission, functionalized as Subtransmission	Transmission lines not eligible for the OATT, including radial transmission, functionalized as Subtransmission	Transmission lines not eligible for the OATT, including radial transmission, functionalized as Subtransmission	Transmission lines not eligible for the OATT, including radial transmission, functionalized as Subtransmission	Transmission lines not eligible for the OATT formerly in Subtransmission, functionalized as Non Tariffable Transmission	Transmission lines not eligible for the OATT formerly in Subtransmission, functionalized as Non Tariffable Transmission
Transmission Interconnections Classification	All Interconnections: Energy	All Interconnections: 2CP Demand	All Interconnections: 2CP Demand	All Interconnections: 2CP Demand	All Interconnections: 2CP Demand	All Interconnections: 2CP Demand	US Interconnections: Weighted Energy incl value of capacity

Cost Assignment: Domestic Direct Costs directly assigned to domestic classes Domestic Pool Costs allocated between domestic classes Domestic/Depend Export Pool Costs allocated between domestic and all dependable exports Domestic/Export Pool Costs allocated between domestic classes and all exports Export Direct Costs directly assigned to exports Opportunity Export Direct Costs directly assigned to Opportunity exports **Defintions:** Unserved Opportunity or Unserved Export: Residual Export load that has not already been deemed served by direct assignment of DSM, water rentals, thermal fuel or power purchases Remaining Costs: Residual costs that remain to be allocated, after the initial direct assignment of Water Rentals to Opportunity Exports **Notes on Other PCOSS Not Included in Chart:** PCOSS08 (July 2007) was prepared using same methodology as PCOSS06 Response to Order 117/06 PCOSS11 (May 25, 2010) was prepared using same methodology as PCOSS10, with the modification to allocate Brandon GS Fuel to domestic classes