MANITOBA PUBLIC UTILITIES BOARD

Re: MANITOBA HYDRO

COST OF SERVICE STUDY REVIEW

INTERVENOR WORKSHOPS

Before Facilitator: Bill Grant

HELD AT:

Public Utilities Board

400, 330 Portage Avenue

Winnipeg, Manitoba

June 21, 2016

Pages 1 to 419

1 APPEARANCES

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20	William Harper	)
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23	David Cordingley	)
24	Paul Chernick	)
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1 APPEARANCES (Cont'd)

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21

22

23

24

25

TABLE OF CONTENTS

	Page No.
List of Exhibits	6
List of Undertakings	86
MIPUG PANEL:	
PATRICK BOWMAN, Sworn	
Presentation by MIPUG	92
Cross-examination by Mr. William Harper	127
Cross-examination by Mr. Paul Chernick	165
Cross-examination by Mr. Jarome Leslie	204
Cross-examination by Mr. Ian Chow	212
Continued Cross-examination by Mr. Jarome Leslie	215
Cross-examination by Ms. Denise Pambrun	220
Cross-examination by Mr. John Todd	245
Cross-examination by Ms. Kelly Derksen	250
Cross-examination by Mr. Johan Athas	289
Cross-examination by Mr. Brady Ryall	326
Continued Cross-examination by Ms. Kelly Derksen	330
Cross-examination by Mr. Michael O'Sheasy	335

TABLE OF CONTENTS (Cont'd)

Page No.

CONSUMER COALITION PANEL:

WILLIAM HARPER, Sworn

Presentation by Consumer Coalition Panel 344

Cross-examination by Ms. Denise Pambrun 375

Cross-examination by Mr. Paul Chernick 388

Certificate of transcript 419

LIST OF EXHIBITS

EXHIBIT NO.	DESCRIPTION	PAGE NO.
PUB-1	PUB to Manitoba Hydro and Intervenors of Record re Manitoba Hydro's Cost of Service filing dated December 8, 2015	
PUB-2	Notice of a Public review of the Cost of Service Study methodology utilized by Manitoba Hydro and other related matters dated January 18, 2016	
PUB-3	PUB to all parties re Process Matters - Manitoba Hydro's Cost of Service study methodology review dated January 22, 2016	
PUB-4	PUB to MH re Access to electronic model dated February 18, 2016	
PUB-5	PUB Order 26/16 dated February 26, 2016 - Procedural Order in respect of Manitoba Hydro's COSS methodology review	
PUB-6	PUB Rules of Practice and Procedure	
PUB-7	Daymark to Manitoba Hydro email re Update on Modelling discussions dated March 9, 2016	

LIST OF EXHIBITS

EXHIBIT NO.	DESCRIPTION	PAGE NO.
PUB-8-1	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. Marginal costs - marginal energy weighting - 12 SEP weighting	
PUB-8-2	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. PCOSS08 - March 2009	
PUB-8-3	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. DSM cost allocation	
PUB-8-4	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. DSM Savings allocation	
PUB-8-5	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. Demand allocation - coincident & non-coincident peak load forecast	

LIST OF EXHIBITS

PUB-8-6	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. IFRS impact on PCOSS
PUB-8-7	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. Net export revenue - allocation of costs to export class
PUB-8-8	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. Recommendations from Christensen Associates - impact of different changes
PUB-8-9	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. Electricity export class - basis for investment decisions.
PUB-8-10	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. Assignment of costs to export class - variable costs to opportunity costs

LIST OF EXHIBITS

EXHIBIT NO.	DESCRIPTION	PAGE NO.
PUB-8-11	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. Assignment of costs to export class.	
PUB-8-12	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. Net export revenue - assignment of costs to export cost	
PUB-8-13	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. Costs of export class assignment - assignment of thermal & coal costs to export class	
PUB-8-14	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. Trading desk - MISO cost assignment	
PUB-8-15	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. Progression of revenue costs coverage (RCC) ratios	

LIST OF EXHIBITS

NO.	DESCRIPTION	PAGE NO.
PUB-8-16	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. Assignment of DSM costs to export class	
PUB-8-17	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. Transmission and distribution marginal costs	
PUB-8-18	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. Allocation of net export revenue to customer classes.	
PUB-8-19	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. Complete version of PCOSS14 amended	
PUB-8-20	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. Domestic & export energy profiles 2014/15	

LIST OF EXHIBITS

PUB-8-21	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. Domestic & export peak demand profiles
PUB-8-22	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. MISO sales history & forecasts
PUB-8-23	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. HVDC & HVAC - Action system utilization
PUB-8-24	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. Functionalization of HVDC - functionalization of transmission facilities as generation
PUB-8-25	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. Hydraulic generation/non-hydraulic generation resources - fixed costs to opportunity sales.

LIST OF EXHIBITS

EXHIBIT NO.	DESCRIPTION	PAGE NO.
PUB-8-26	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. Diversity sales/purchases - MISO benefits vs MH benefits	
PUB-8-27	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. PCOSS14 116-08, PCOSS 14 amended - DSM add-back to domestic load	
PUB-8-28	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. Cost assignment to dependable & opportunity export sales	
PUB-8-29	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. Keeyask capital cost - marginal cost/benefit of additional units	

LIST OF EXHIBITS

EXHIBIT NO.	DESCRIPTION	PAGE NO.
PUB-8-30	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. Transmission cost allocation - seasonal 2CP at generation	
PUB-8-31	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. Average monthly demand - marginal cost weighting of energy/demand	
PUB-8-32	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. Market price of power in extraprovincial jurisdictions	
PUB-8-33	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. Service extension policy	
PUB-8-34	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. Rate design - basic charges, demand charges, & energy charges	

LIST OF EXHIBITS

EXHIBIT NO.	DESCRIPTION	PAGE NO.
PUB-8-35	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. Rate design principles - lowering of the basic charge	
PUB-8-36	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. MISO imports & wind purchases	
PUB-8-37	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. 2013/14, 2014/15 and 2015/16 NEB data	
PUB-8-38	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. Future G&T assets	
PUB-8-39	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. Generation/transmission/distribution costs	

LIST OF EXHIBITS

EXHIBIT NO.	DESCRIPTION	PAGE NO.
PUB-8-40	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. Non Hydraulic resources - cost effective use of resources	
PUB-8-41	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. Generation and transmission in cost sharing - 7x16 opportunity sales	
PUB-8-42	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. Generation and transmission in cost sharing - 7x16 opportunity sales	
PUB-8-43	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. Allocation of net export revenue - basis of allocation	

LIST OF EXHIBITS

Exhibit No.	Description	Page No.
PUB-8-44	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. Classification of generation costs	
PUB-8-45	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. Functionalization of communications equipment	
PUB-8-46	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. Functionalization of buildings & equipment	
PUB-8-47	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. Functionalization of communications equipment	
PUB-8-48	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. Classification of distribution costs	

LIST OF EXHIBITS

EXHIBIT NO.	DESCRIPTION	PAGE NO.
PUB-8-49	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. Primary/Secondary split distribution costs	
PUB-8-50	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. Assignment to dependable & opportunity sales - hybrid sales	
PUB-8-51	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. Capacity value - demand-based allocation of generation	
PUB-8-52	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. Marginal cost weights - impact of transmission constraints on marginal cost	
PUB-8-53	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. External allocators - data sources	

LIST OF EXHIBITS

EXHIBIT NO.	DESCRIPTION	PAGE NO.
PUB-8-54	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. Peak load data - NCP allocation	
PUB-8-55	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. Functionalization of HVDC - Bipole III - Impact on COS	
PUB-8-56	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. Generation costs - costs of individual hydro dams	
PUB-8-57	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. Customer allocators - vintage of analysis	
PUB-8-58	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. Customer allocators - service drops per customer	

LIST OF EXHIBITS

EXHIBIT NO.	DESCRIPTION	PAGE NO.
PUB-8-59	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. Allocation of DSM costs	
PUB-8-60	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. Allocation of net export revenue and net income	
PUB-8-61	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. Allocation of costs associated with the US interconnections	
PUB-8-62	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. Allocation of net export revenue	
PUB-8-63	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. Hydraulic generation cost sharing	

LIST OF EXHIBITS

EXHIBIT NO.	DESCRIPTION	PAGE NO.
PUB-8-64	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. HVDC cost implications.	
PUB-8-65	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. Exports into MISO 2013/14, 2014/15 & 2015/16	
PUB-8-66	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. Hydraulic generation resources - planning assumption vs utilization	
PUB-8-67	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. Keeyask business case - anticipated firm sales	
PUB-8-68	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. HYDC demand allocation - 2CP vs weighted energy	

LIST OF EXHIBITS

EXHIBIT NO.	DESCRIPTION	PAGE NO.
PUB-8-69	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. Functionalization of rate base - changes in rate base - impact on COSS	
PUB-8-70	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. Allocation of revenue requirement	
PUB-8-71	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. Export and domestic revenue	
PUB-8-72	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. Distribution plant - service voltage	
PUB-8-73	Public Utilities Board (PUB) to Manitoba Hydro (MH) - 1st Round Information Requests. 2CP & NCP	
PUB-9	PUB to MH and registered Intervenors re Intervenor Cost of Service model runs letter dated March 29, 2016	

1 LIST OF EXHIBITS

EXHIBIT NO.	DESCRIPTION	PAGE NO.
PUB-10	PUB to Intervenors letter re budgets dated April 4, 2016	
PUB-11	PUB to Intervenors letter re interim invoices April 8, 2016	
PUB-12	PUB follow-up questions to Manitoba Hydro for May 2016 Workshop - May 10, 2016	
PUB-13	Pre-hearing conference - transcripts	
MH-1	Manitoba Hydro to PUB re Cost of Service Study Review Submission - cover letter dated December 4, 2015	
MH-2	Cost of Service Study Review Submission	
MH-3	Manitoba Hydro to PUB re cost of service study review submission - cover letter dated December 18, 2015	
MH-4	Manitoba Hydro to PUB re Cost of Service review process dated February 5, 2016	
MH-5	Manitoba Hydro's pre-hearing conference presentation - February 12, 2016	
MH-6	Manitoba Hydro's proposed scope of issues - 2016 Cost of Service Review	

1 LIST OF EXHIBITS

EXHIBIT NO.	DESCRIPTION	PAGE NO.
MH-7	MH to PUB letter re 2016 COS review - model dated February 22, 2016	
MH-8	MH to PUB letter re Model (response to Intervenors' comments) dated February 24, 2016	
MH-9	MH to PUB re COSS review - minimum filing requirements & other matters dated February 26, 2016	
MH-10	MH to PUB re MFRs and other matters - cover letter dated March 2, 2016	
MH-11	MH to Daymark letter re cost of service model dated March 11, 2016 in response to Daymark's letter of March 9, 2016	
MH-12	MH to Daymark letter re cost of service model dated March 16, 2016 - follow-up to March 11, 2016 response	
MH-13	MH to Daymark letter re cost of service model dated March 22, 2016 - follow-up to March 11, 2016 response	
MH-14	MH to PUB letter re Filing of responses to Information Requests dated April 21, 2016	

1 LIST OF EXHIBITS

EXHIBIT NO.	DESCRIPTION	PAGE NO.
MH-15	MH to PUB letter re Filing of responses to Information Requests dated April 22, 2016	
MH-16	MH to PUB letter re Filing of responses to Information Requests dated April 25, 2016	
MH-17	MH to PUB letter re Filing of responses to Information Requests dated April 27, 2016	
MH-18	MH to PUB letter re Filing of responses to Information Requests dated April 30, 2016	
MH-19	MH to PUB letter re Workshop dated May 10, 2016	
MH-20	MH presentation - cost of service methodology workshop - May 11, 2016	
MH-21	MH CEC report - Bipole III project needs and alternatives	
MH-22	MH Exhibit No. 41 from Manitoba Hydro's 2012/2013 & 2013/14 General Rate Application	
MH-23	MH to PUB letter re workshop undertakings dated May 30, 2016	

1 LIST OF EXHIBITS

2 EXHIBIT NO. DESCRIPTION PAGE NO.

3 MH-24 Response to Undertaking No. 1 - PCOSS
4 schedules (incl. schedule B2 & B3
5 without net export revenue and D1 & D2)
6 - marginal weighted energy "capacity
7 adder" added only the winter peak
8 period
9 MH-25 Response to Undertaking No. 2 - PCOSS
10 schedules with the scenario provide on
11 slide 20 of MH-20 and schedules B2 and
12 B3 without deducting the net expert
13 revenue
14 MH-26 Response to Undertaking No. 3 - Monthly
15 MISO voluntary capacity auction prices
16 for the period of 2009 to 2013
17 MH-27 Response to Undertaking No. 4. MH to
18 confirm whether all the times that were
19 given in the discovery responses are
20 for hour ending.
21 MH-28 Response to Undertaking No. 5 -
22 revised. Schedule of historic export
23 sales from 2005 to 2014 year for all
24 hours.
25

LIST OF EXHIBITS

EXHIBIT NO.	DESCRIPTION	PAGE NO.
MH-29	Response to Undertaking No. 6. Allocation basis for indirect costs.	
MH-30	Response to Undertaking No. 7. RCCs and percentages underpinning Slide 39 of MH-20	
MH-31	Response to Undertaking No. 8. Hourly load profile data for exports.	
MH-32	Response to Undertaking No. 9. PUB/MH I-22b with MISO financial sales data.	
MH-33	Response to Undertaking No. 10. WPS NE permit 379 sales (GWh)	
MH-34	Response to Undertaking No. 11. Cost difference among the three (3) types of poles.	
MH-35	Response to Undertaking No. 12. Length of secondary cable	
MH-36	Response to Undertaking No. 13. Conductor length for overhead distribution.	
MH-37	Response to Undertaking No. 14. Night time hours to determine coincident peak and non-coincident peak (for streetlights)	

LIST OF EXHIBITS

EXHIBIT NO.	DESCRIPTION	PAGE NO.
MH-38	Response to Undertaking No. 15. Excel file with annual average load profiles by customer class for years 2012/2013 and 2013/2014	
MH-39	Response to Undertaking No. 16. Schedules B2 and B3 without the net (export) revenue being deducted.	
MH-40	Response to Undertaking No. 17. Planned orders by SCC.	
MH-41	Response to Undertaking No. 21. List of assets moved out of subtransmission to distribution.	
MH-42	Response to Undertaking No. 22. Website link to schedule of additional charges.	
MH-43	Response to Undertaking No. 23. Monthly capacity factor data for Kettle, Long Spruce and Limestone GS for 2002/03, 2003/04, 2013/14, 2014/15 and 2015/16.	
MH-44	Response to Undertaking No. 24a. Excel file - attachment to PUB/MH 1-5a-d	
MH-45	Response to Undertaking No. 24b. Excel file - PUB/MH 1-30c.	

LIST OF EXHIBITS

EXHIBIT NO.	DESCRIPTION	PAGE NO.
MH-46	Response to Undertaking No. 24c. Excel file - PUB/MH 1-60d.	
MH-47	Response to Undertaking No. 24d. Excel file - PUB/MH 1-65a	
MH-48	Response to Undertaking No. 24e. Excel file - PUB/MH 1-70.	
MH-49	Response to Undertaking No. 25. Schedules C6 and C8 - basis for distribution and operating costs being refunctionalized from subtransmission to distribution	
MH-50	Response to Undertaking No. 26. Net regulated/intangible costs that are functionalized to distribution.	
MH-51	Response to Undertaking No. 27. Breakdown of underground cable plan investment between primary and secondary.	
MH-52	Response to Undertaking No. 28. GAC/MH l-21, table on page 3 of the response	
MH-53	Response to Undertaking No. 29. Line extension policies	

1 LIST OF EXHIBITS

2 EXHIBIT NO. DESCRIPTION PAGE NO.

3 MH-54 Response to Undertaking No. 30. Motor
4 vehicle rate base
5 MH-55 Response to Undertaking - transcript
6 page 254. GAC/MH 1-57 and GAC/MH 1-8.
7 MH-56 Response to Undertaking - transcript
8 page 255. GAC/MH 1-57 - common bus.
9 MH-57 Response to Undertaking - transcript
10 page 602. Top 50 hours (summer and
11 winter) at the common bus.
12 MH-58 Response to Undertaking - transcript
13 page 603. Monthly peak loads for
14 domestic load only, domestic loads and
15 dependable exports and domestic load
16 and dependable and opportunity exports.
17 MH-59 Response to Undertaking - transcript
18 page 791. C10 allocator
19 MH-60 MH to PUB cover letter re Undertaking
20 No. 19 dated May 31, 2016
21 MH-61 Undertaking No. 19. Calculation of
22 direct, indirect and incremental costs.
23 MH-62 MH to PUB cover letter re Undertaking
24 No. 5 dated June 8, 2016
25

1 LIST OF EXHIBITS

2 EXHIBIT NO. DESCRIPTION PAGE NO.

3 Coalition-1 Consumer Coalitions' response to PUB's
4 December 8, 2015 letter re Additional
5 minimum filing requirements dated
6 December 15, 2015
7 Coalition-2 Consumer Coalition - Intervenor
8 application.
9 Coalition-2-1 Consumer Coalition - preliminary issue
10 summary
11 Coalition-2-2 Consumer Coalition - Appendix B -
12 William Harper's COSS and rate design
13 qualifications.
14 Coalition-3 MH COSS review - evidence of William
15 Harper - March 16, 2006
16 Coalition-4 Consumer Coalition - written submission
17 in response to PUB's letter of January
18 22, 2016 - dated February 10, 2016
19 Coalition-5 Pre-hearing conference presentation -
20 February 12, 2016
21 Coalition-6 Consumer Coalition's presentation -
22 appendix 1 - COSS process and timelines
23 Coalition-7 Consumer Coalition letter to PUB re
24 model dated February 23, 2016
25

LIST OF EXHIBITS

Coalition-8	Consumer Coalition's budget estimates for Hydro cost of service proceeding dated March 1, 2016
Coalition-9	Proposed schedule dated March 1, 2016
Coalition-10	Coalition's preliminary comments with regard to the Hydro COS model - March 4, 2016 revised
Coalition-11	Consumers' Association of Canada (Manitoba) and Winnipeg Harvest (Coalition) to Manitoba Hydro - 1st round of information Requests. Proof of revenue calculations
Coalition-11-2	Consumers' Association of Canada (Manitoba) and Winnipeg Harvest (Coalition) to Manitoba Hydro - 1st round of information Requests. Financial forecast reconciliation - other revenue
Coalition-11-3	Consumers' Association of Canada (Manitoba) and Winnipeg Harvest (Coalition) to Manitoba Hydro - 1st round of information Requests. Financial forecast reconciliation - revenue - miscellaneous - non energy.

1 LIST OF EXHIBITS

2 EXHIBIT NO. DESCRIPTION PAGE NO.

3 Coalition-11-4 Consumers' Association of Canada
4 (Manitoba) and Winnipeg Harvest
5 (Coalition) to Manitoba Hydro - 1st
6 round of information Requests.
7 Financial forecast reconciliation -
8 revenue - late payment charges and
9 customer adjustment
10 Coalition-11-5 Consumers' Association of Canada
11 (Manitoba) and Winnipeg Harvest
12 (Coalition) to Manitoba Hydro - 1st
13 round of information Requests.
14 Financial forecast reconciliation - O&A
15 costs - assignment of cost centres
16 Coalition-11-6 Consumers' Association of Canada
17 (Manitoba) and Winnipeg Harvest
18 (Coalition) to Manitoba Hydro - 1st
19 round of information Requests.
20 Financial forecast reconciliation -
21 depreciation - capital contributions.
22
23
24
25

1 LIST OF EXHIBITS

2 EXHIBIT NO. DESCRIPTION PAGE NO.

3 Coalition-11-7 Consumers' Association of Canada
4 (Manitoba) and Winnipeg Harvest
5 (Coalition) to Manitoba Hydro - 1st
6 round of information Requests.
7 Financial forecast reconciliation -
8 depreciation - capital contributions.
9 Coalition-11-8 Consumers' Association of Canada
10 (Manitoba) and Winnipeg Harvest
11 (Coalition) to Manitoba Hydro - 1st
12 round of information Requests.
13 Financial forecast reconciliation -
14 depreciation - diesel contributions.
15 Coalition-11-9 Consumers' Association of Canada
16 (Manitoba) and Winnipeg Harvest
17 (Coalition) to Manitoba Hydro - 1st
18 round of information Requests.
19 Financial forecast reconciliation -
20 interest and reserve contributions -
21 capital tax.
22
23
24
25

1 LIST OF EXHIBITS

2 EXHIBIT NO. DESCRIPTION PAGE NO.

3 Coalition-11-10 Consumers' Association of Canada
4 (Manitoba) and Winnipeg Harvest
5 (Coalition) to Manitoba Hydro - 1st
6 round of information Requests.
7 Financial forecast reconciliation -
8 interest and reserve contributions -
9 corporate allocation.

10 Coalition-11-11 Consumers' Association of Canada
11 (Manitoba) and Winnipeg Harvest
12 (Coalition) to Manitoba Hydro - 1st
13 round of information Requests.
14 Financial forecast reconciliation -
15 interest and reserve contributions
16 and capital tax

17 Coalition-11-12 Consumers' Association of Canada
18 (Manitoba) and Winnipeg Harvest
19 (Coalition) to Manitoba Hydro - 1st
20 round of information Requests.
21 Financial forecast reconciliation -
22 rate base - COSS adjustments

23

24

25

1 LIST OF EXHIBITS

EXHIBIT NO.	DESCRIPTION	PAGE NO.
Coalition-11-13	Consumers' Association of Canada (Manitoba) and Winnipeg Harvest (Coalition) to Manitoba Hydro - 1st round of information Requests. Functionalization - fixed assets - assignment to asset classes.	
Coalition-11-14	Consumers' Association of Canada (Manitoba) and Winnipeg Harvest (Coalition) to Manitoba Hydro - 1st round of information Requests. Functionalization - rate base - regulated assets/intangibles.	
Coalition-11-15	Consumers' Association of Canada (Manitoba) and Winnipeg Harvest (Coalition) to Manitoba Hydro - 1st round of information Requests. Reconciliation of financial forecast - revenue requirement components - changes in values	

1 LIST OF EXHIBITS

EXHIBIT NO.	DESCRIPTION	PAGE NO.
Coalition-11-16	Consumers' Association of Canada (Manitoba) and Winnipeg Harvest (Coalition) to Manitoba Hydro - 1st round of information Requests. Direct assignment - generation exports - nature of directly assigned costs.	
Coalition-11-17	Consumers' Association of Canada (Manitoba) and Winnipeg Harvest (Coalition) to Manitoba Hydro - 1st round of information Requests. Direct assignment - generation exports - PCOSS14 - amended changes	
Coalition-11-18	Consumers' Association of Canada (Manitoba) and Winnipeg Harvest (Coalition) to Manitoba Hydro - 1st round of information Requests. Direct assignment - DSM - apportionment to customer classes	

1 LIST OF EXHIBITS

EXHIBIT NO.	DESCRIPTION	PAGE NO.
Coalition-11-19	Consumers' Association of Canada (Manitoba) and Winnipeg Harvest (Coalition) to Manitoba Hydro - 1st round of information Requests. Direct assignment - DSM - benefits of DSM	
Coalition-11-20	Consumers' Association of Canada (Manitoba) and Winnipeg Harvest (Coalition) to Manitoba Hydro - 1st round of information Requests. Direct assignment - SEP - basis for costs assigned.	
Coalition-11-21	Consumers' Association of Canada (Manitoba) and Winnipeg Harvest (Coalition) to Manitoba Hydro - 1st round of information Requests. Export class - dependable versus opportunity exports - basis for dependable/export split	

LIST OF EXHIBITS

EXHIBIT NO.	DESCRIPTION	PAGE NO.
Coalition-11-22	Consumers' Association of Canada (Manitoba) and Winnipeg Harvest (Coalition) to Manitoba Hydro - 1st round of information Requests. Export class - dependable versus opportunity exports - types of long term contracts	
Coalition-11-23	Consumers' Association of Canada (Manitoba) and Winnipeg Harvest (Coalition) to Manitoba Hydro - 1st round of information Requests. Export class - dependable versus opportunity exports - hybrid sales	
Coalition-11-24	Consumers' Association of Canada (Manitoba) and Winnipeg Harvest (Coalition) to Manitoba Hydro - 1st round of information Requests. Export class - dependable versus opportunity exports - transmission service requirements	

LIST OF EXHIBITS

EXHIBIT NO.	DESCRIPTION	PAGE NO.
Coalition-11-25	Consumers' Association of Canada (Manitoba) and Winnipeg Harvest (Coalition) to Manitoba Hydro - 1st round of information Requests. Export class - dependable versus opportunity exports - impacts on investment	
Coalition-11-26	Consumers' Association of Canada (Manitoba) and Winnipeg Harvest (Coalition) to Manitoba Hydro - 1st round of information Requests. Functionalization - operating costs - generation facilities and costs.	
Coalition-11-27	Consumers' Association of Canada (Manitoba) and Winnipeg Harvest (Coalition) to Manitoba Hydro - 1st round of information Requests. Functionalization - operating costs - transmission facilities and costs	

LIST OF EXHIBITS

EXHIBIT NO.	DESCRIPTION	PAGE NO.
Coalition-11-28	Consumers' Association of Canada (Manitoba) and Winnipeg Harvest (Coalition) to Manitoba Hydro - 1st round of information Requests. Functionalization - operating costs - communications and control systems	
Coalition-11-29	Consumers' Association of Canada (Manitoba) and Winnipeg Harvest (Coalition) to Manitoba Hydro - 1st round of information Requests. Functionalization - operating costs - treatment of specific facilities' costs	
Coalition-11-30	Consumers' Association of Canada (Manitoba) and Winnipeg Harvest (Coalition) to Manitoba Hydro - 1st round of information Requests. Functionalization - depreciation - generation facilities and costs	

LIST OF EXHIBITS

EXHIBIT NO.	DESCRIPTION	PAGE NO.
Coalition-11-31	Consumers' Association of Canada (Manitoba) and Winnipeg Harvest (Coalition) to Manitoba Hydro - 1st round of information Requests. Functionalization - depreciation - transmission facilities and costs	
Coalition-11-32	Consumers' Association of Canada (Manitoba) and Winnipeg Harvest (Coalition) to Manitoba Hydro - 1st round of information Requests. Functionalization - depreciation - communications and control systems	
Coalition-11-33	Consumers' Association of Canada (Manitoba) and Winnipeg Harvest (Coalition) to Manitoba Hydro - 1st round of information Requests. Functionalization - depreciation costs - treatment of specific facilities' costs	

1 LIST OF EXHIBITS

2 EXHIBIT NO. DESCRIPTION PAGE NO.

3 Coalition-11-34 Consumers' Association of Canada
4 (Manitoba) and Winnipeg Harvest
5 (Coalition) to Manitoba Hydro - 1st
6 round of information Requests.
7 Functionalization - assets and
8 investments - assignment to
9 functions - general

10 Coalition-11-35 Consumers' Association of Canada
11 (Manitoba) and Winnipeg Harvest
12 (Coalition) to Manitoba Hydro - 1st
13 round of information Requests.
14 Functionalization - assets and
15 investments - assignment to
16 functions - buildings, communication
17 and general equipment

18 Coalition-11-36 Consumers' Association of Canada
19 (Manitoba) and Winnipeg Harvest
20 (Coalition) to Manitoba Hydro - 1st
21 round of information Requests.
22 Functionalization - assets and
23 investments - assignment to
24 functions - buildings, communication
25 and general equipment.

LIST OF EXHIBITS

EXHIBIT NO.	DESCRIPTION	PAGE NO.
Coalition-11-37	Consumers' Association of Canada (Manitoba) and Winnipeg Harvest (Coalition) to Manitoba Hydro - 1st round of information Requests. Functionalization - non-tariffable transmission - MISO requirements	
Coalition-11-38	Consumers' Association of Canada (Manitoba) and Winnipeg Harvest (Coalition) to Manitoba Hydro - 1st round of information Requests. Functionalization - non-tariffable transmission - radial lines	
Coalition-11-39	Consumers' Association of Canada (Manitoba) and Winnipeg Harvest (Coalition) to Manitoba Hydro - 1st round of information Requests. Functionalization - non-tariffable transmission - radial lines	

1 LIST OF EXHIBITS

2 EXHIBIT NO. DESCRIPTION PAGE NO.

3 Coalition-11-40 Consumers' Association of Canada
4 (Manitoba) and Winnipeg Harvest
5 (Coalition) to Manitoba Hydro - 1st
6 round of information Requests.
7 Functionalization - northern
8 collector circuits.

9 Coalition-11-41 Consumers' Association of Canada
10 (Manitoba) and Winnipeg Harvest
11 (Coalition) to Manitoba Hydro - 1st
12 round of information Requests.
13 Functionalization - Bipole l and ll
14 - treatment as generation

15 Coalition-11-42 Consumers' Association of Canada
16 (Manitoba) and Winnipeg Harvest
17 (Coalition) to Manitoba Hydro - 1st
18 round of information Requests.
19 Functionalization - Bipole l and ll
20 - proposed treatment as generation

21 Coalition-11-43 Consumers' Association of Canada
22 (Manitoba) and Winnipeg Harvest
23 (Coalition) to Manitoba Hydro - 1st
24 round of information Requests.
25 Functionalization - Bipole lll -

LIST OF EXHIBITS

EXHIBIT NO.	DESCRIPTION	PAGE NO.
	transmission facilities - proposed future treatment as generation	
Coalition-11-44	Consumers' Association of Canada (Manitoba) and Winnipeg Harvest (Coalition) to Manitoba Hydro - 1st round of information Requests. Functionalization - Bipole lll - transmission facilities - proposed future treatment as generation	
Coalition-11-45	Consumers' Association of Canada (Manitoba) and Winnipeg Harvest (Coalition) to Manitoba Hydro - 1st round of information Requests. Functionalization - Dorsey - treatment as generation	
Coalition-11-46	Consumers' Association of Canada (Manitoba) and Winnipeg Harvest (Coalition) to Manitoba Hydro - 1st round of information Requests. Functionalization - Dorsey - treatment as generation	

1 LIST OF EXHIBITS

2 EXHIBIT NO. DESCRIPTION PAGE NO.

3 Coalition-11-47 Consumers' Association of Canada
4 (Manitoba) and Winnipeg Harvest
5 (Coalition) to Manitoba Hydro - 1st
6 round of information Requests.
7 Functionalization - Riel - treatment
8 as generation

9 Coalition-11-48 Consumers' Association of Canada
10 (Manitoba) and Winnipeg Harvest
11 (Coalition) to Manitoba Hydro - 1st
12 round of information Requests.
13 Functionalization - Riel - treatment
14 as generation

15 Coalition-11-49 Consumers' Association of Canada
16 (Manitoba) and Winnipeg Harvest
17 (Coalition) to Manitoba Hydro - 1st
18 round of information Requests.
19 Functionalization - Distribution -
20 sub functionalization of
21 distribution plant

22

23

24

25

1 LIST OF EXHIBITS

EXHIBIT NO.	DESCRIPTION	PAGE NO.
Coalition-11-50	Consumers' Association of Canada (Manitoba) and Winnipeg Harvest (Coalition) to Manitoba Hydro - 1st round of information Requests. Functionalization - Distribution - primary vs. secondary distribution	
Coalition-11-51	Consumers' Association of Canada (Manitoba) and Winnipeg Harvest (Coalition) to Manitoba Hydro - 1st round of information Requests. Functionalization - Distribution services - cost assignment to sub-functions	
Coalition-11-52	Consumers' Association of Canada (Manitoba) and Winnipeg Harvest (Coalition) to Manitoba Hydro - 1st round of information Requests. Classification/allocation - generation - Christensen Associates' 2012 recommendations	

LIST OF EXHIBITS

EXHIBIT NO.	DESCRIPTION	PAGE NO.
Coalition-11-53	Consumers' Association of Canada (Manitoba) and Winnipeg Harvest (Coalition) to Manitoba Hydro - 1st round of information Requests. Classification/Allocation - Generation - determination of marginal cost weightings.	
Coalition-11-54	Consumers' Association of Canada (Manitoba) and Winnipeg Harvest (Coalition) to Manitoba Hydro - 1st round of information Requests. Classification/Allocation - Generation - Christensen Associates' 2015 recommendations	
Coalition-11-55	Consumers' Association of Canada (Manitoba) and Winnipeg Harvest (Coalition) to Manitoba Hydro - 1st round of information Requests. Classification/Allocation - Generation - Christensen Associates' 2015 recommendations	

LIST OF EXHIBITS

EXHIBIT NO.	DESCRIPTION	PAGE NO.
Coalition-11-56	Consumers' Association of Canada (Manitoba) and Winnipeg Harvest (Coalition) to Manitoba Hydro - 1st round of information Requests. Classification/Allocation - Generation - Determination of marginal cost weightings.	
Coalition-11-57	Consumers' Association of Canada (Manitoba) and Winnipeg Harvest (Coalition) to Manitoba Hydro - 1st round of information Requests. Classification/Allocation - Generation - Determination of marginal cost weightings.	
Coalition-11-58	Consumers' Association of Canada (Manitoba) and Winnipeg Harvest (Coalition) to Manitoba Hydro - 1st round of information Requests. Classification/Allocation - Generation - Determination of marginal cost weightings.	

1 LIST OF EXHIBITS

2 Coalition-11-59 Consumers' Association of Canada
3 (Manitoba) and Winnipeg Harvest
4 (Coalition) to Manitoba Hydro - 1st
5 round of information Requests.
6 Classification/Allocation -
7 Generation - wind.
8 Coalition-11-60 Consumers' Association of Canada
9 (Manitoba) and Winnipeg Harvest
10 (Coalition) to Manitoba Hydro - 1st
11 round of information Requests.
12 Classification/Allocation -
13 Generation - purchased power
14 Coalition-11-61 Consumers' Association of Canada
15 (Manitoba) and Winnipeg Harvest
16 (Coalition) to Manitoba Hydro - 1st
17 round of information Requests.
18 Classification/Allocation -
19 Generation - purchased power
20 Coalition-11-62 Consumers' Association of Canada
21 (Manitoba) and Winnipeg Harvest
22 (Coalition) to Manitoba Hydro - 1st
23 round of information Requests.
24 Classification/Allocation -
25 Generation - thermal generation

1 LIST OF EXHIBITS

EXHIBIT NO.	DESCRIPTION	PAGE NO.
Coalition-11-63	Consumers' Association of Canada (Manitoba) and Winnipeg Harvest (Coalition) to Manitoba Hydro - 1st round of information Requests. Classification/Allocation - Generation - Coal fixed thermal generation	
Coalition-11-64	Consumers' Association of Canada (Manitoba) and Winnipeg Harvest (Coalition) to Manitoba Hydro - 1st round of information Requests. Classification/Allocation - Generation - Trading desks and MISO/MAPP fees	
Coalition-11-65	Consumers' Association of Canada (Manitoba) and Winnipeg Harvest (Coalition) to Manitoba Hydro - 1st round of information Requests. Classification/Allocation - Generation - domestic lines	

1 LIST OF EXHIBITS

2 EXHIBIT NO. DESCRIPTION PAGE NO.

3 Coalition-11-66 Consumers' Association of Canada
4 (Manitoba) and Winnipeg Harvest
5 (Coalition) to Manitoba Hydro - 1st
6 round of information Requests.
7 Classification/Allocation -
8 Transmission - determination of 2CP
9 allocator
10 Coalition-11-67 Consumers' Association of Canada
11 (Manitoba) and Winnipeg Harvest
12 (Coalition) to Manitoba Hydro - 1st
13 round of information Requests.
14 Classification/Allocation -
15 Transmission - interconnections -
16 definitions
17 Coalition-11-68 Consumers' Association of Canada
18 (Manitoba) and Winnipeg Harvest
19 (Coalition) to Manitoba Hydro - 1st
20 round of information Requests.
21 Classification/Allocation -
22 Transmission - interconnections -
23 definitions
24
25

1 LIST OF EXHIBITS

2 EXHIBIT NO. DESCRIPTION PAGE NO.

3 Coalition-11-69 Consumers' Association of Canada
4 (Manitoba) and Winnipeg Harvest
5 (Coalition) to Manitoba Hydro - 1st
6 round of information Requests.
7 Classification/Allocation -
8 Distribution plant - classification
9 of distribution facilities
10 Coalition-11-70 Consumers' Association of Canada
11 (Manitoba) and Winnipeg Harvest
12 (Coalition) to Manitoba Hydro - 1st
13 round of information Requests.
14 Classification/Allocation -
15 Distribution plant - classification
16 of distribution facilities
17 Coalition-11-71 Consumers' Association of Canada
18 (Manitoba) and Winnipeg Harvest
19 (Coalition) to Manitoba Hydro - 1st
20 round of information Requests.
21 Classification/Allocation -
22 Distribution plant - distribution
23 lines and poles - secondary
24 adjustment
25

LIST OF EXHIBITS

EXHIBIT NO.	DESCRIPTION	PAGE NO.
Coalition-11-72	Consumers' Association of Canada (Manitoba) and Winnipeg Harvest (Coalition) to Manitoba Hydro - 1st round of information Requests. Classification/Allocation - Distribution plant - treatment of GSL 0-30 kV rate class	
Coalition-11-73	Consumers' Association of Canada (Manitoba) and Winnipeg Harvest (Coalition) to Manitoba Hydro - 1st round of information Requests. Classification/Allocation - Distribution plant - treatment of ARL	
Coalition-11-74	Consumers' Association of Canada (Manitoba) and Winnipeg Harvest (Coalition) to Manitoba Hydro - 1st round of information Requests. Classification/Allocation - Distribution plant - weightings for services, meters and meter maintenance	

LIST OF EXHIBITS

EXHIBIT NO.	DESCRIPTION	PAGE NO.
Coalition-11-75	Consumers' Association of Canada (Manitoba) and Winnipeg Harvest (Coalition) to Manitoba Hydro - 1st round of information Requests. Classification/Allocation - Distribution plant - customer weighting factor	
Coalition-11-76	Consumers' Association of Canada (Manitoba) and Winnipeg Harvest (Coalition) to Manitoba Hydro - 1st round of information Requests. Net export revenue - allocation - determination of allocation factors	
Coalition-11-77	Consumers' Association of Canada (Manitoba) and Winnipeg Harvest (Coalition) to Manitoba Hydro - 1st round of information Requests. Terms and conditions of service - service agreement - payments required	

1 LIST OF EXHIBITS

2 EXHIBIT NO. DESCRIPTION PAGE NO.

3 Coalition-11-78 Consumers' Association of Canada
4 (Manitoba) and Winnipeg Harvest
5 (Coalition) to Manitoba Hydro - 1st
6 round of information Requests. Terms
7 and conditions of service - service
8 agreement - new versus existing
9 services
10 Coalition-11-79 Consumers' Association of Canada
11 (Manitoba) and Winnipeg Harvest
12 (Coalition) to Manitoba Hydro - 1st
13 round of information Requests. Terms
14 and conditions of service - service
15 agreement - payment and notice
16 periods
17 Coalition-11-80 Consumers' Association of Canada
18 (Manitoba) and Winnipeg Harvest
19 (Coalition) to Manitoba Hydro - 1st
20 round of information Requests.
21 Service extension policy - capital
22 contributions - residential service
23 customers.
24
25

1 LIST OF EXHIBITS

2 EXHIBIT NO. DESCRIPTION PAGE NO.

3 Coalition-11-81 Consumers' Association of Canada
4 (Manitoba) and Winnipeg Harvest
5 (Coalition) to Manitoba Hydro - 1st
6 round of information Requests.
7 Service extension policy - capital
8 contributions - general service
9 (small and medium) customers
10 Coalition-11-82 Consumers' Association of Canada
11 (Manitoba) and Winnipeg Harvest
12 (Coalition) to Manitoba Hydro - 1st
13 round of information Requests.
14 Service extension policy - capital
15 contributions - customers <30 kV
16 Coalition-11-83 Consumers' Association of Canada
17 (Manitoba) and Winnipeg Harvest
18 (Coalition) to Manitoba Hydro - 1st
19 round of information Requests.
20 Service extension policy - capital
21 contributions - customers <30 kV -
22 with customer owned transformation.
23
24
25

1 LIST OF EXHIBITS

EXHIBIT NO.	DESCRIPTION	PAGE NO.
Coalition-11-84	Consumers' Association of Canada (Manitoba) and Winnipeg Harvest (Coalition) to Manitoba Hydro - 1st round of information Requests. Service extension policy - capital contributions - customers <30 kV or > 5 MW	
Coalition-11-85	Consumers' Association of Canada (Manitoba) and Winnipeg Harvest (Coalition) to Manitoba Hydro - 1st round of information Requests. Cost of service study - PCOSS14 - amended - compliance with Board Directives (117/06 and 116/08)	
Coalition-11-86	Consumers' Association of Canada (Manitoba) and Winnipeg Harvest (Coalition) to Manitoba Hydro - 1st round of information Requests. Cost of service study - PCOSS14 - Amended - impact of compliance with Board directives.	

LIST OF EXHIBITS

EXHIBIT NO.	DESCRIPTION	PAGE NO.
Coalition-11-87	Consumers' Association of Canada (Manitoba) and Winnipeg Harvest (Coalition) to Manitoba Hydro - 1st round of information Requests. Allocation - transmission - Use of 2CP allocator	
Coalition-11-88	Consumers' Association of Canada (Manitoba) and Winnipeg Harvest (Coalition) to Manitoba Hydro - 1st round of information Requests. Reconciliation of financial forecast - O&A costs - DSM	
Coalition-11-89	Consumers' Association of Canada (Manitoba) and Winnipeg Harvest (Coalition) to Manitoba Hydro - 1st round of information Requests. Export class - dependable versus opportunity exports - basis for dependable/export split.	

1 LIST OF EXHIBITS

EXHIBIT NO.	DESCRIPTION	PAGE NO.
Coalition-11-90	Consumers' Association of Canada (Manitoba) and Winnipeg Harvest (Coalition) to Manitoba Hydro - 1st round of information Requests. Cost of service study - PCOSS14 - amended - comparative results	
Coalition-11-91	Consumers' Association of Canada (Manitoba) and Winnipeg Harvest (Coalition) to Manitoba Hydro - 1st round of information Requests. Functionization - export costs - treatment of transmission service costs	
Coalition-11-92	Consumers' Association of Canada (Manitoba) and Winnipeg Harvest (Coalition) to Manitoba Hydro - 1st round of information Requests. Classification/allocation - transmission - interconnections - costs.	

1 LIST OF EXHIBITS

2 EXHIBIT NO. DESCRIPTION PAGE NO.

3 Coalition-11-93 Consumers' Association of Canada
4 (Manitoba) and Winnipeg Harvest
5 (Coalition) to Manitoba Hydro - 1st
6 round of information Requests.
7 Allocation - GSS classes - customer
8 counts used

9 Coalition-11-94 Consumers' Association of Canada
10 (Manitoba) and Winnipeg Harvest
11 (Coalition) to Manitoba Hydro - 1st
12 round of information Requests.
13 Functionization - ancillary services
14 - generation and transmission assets
15 included

16 Coalition-11-95 Consumers' Association of Canada
17 (Manitoba) and Winnipeg Harvest
18 (Coalition) to Manitoba Hydro - 1st
19 round of information Requests. Cost
20 of service study - goals - approach
21 to cost causation

22

23

24

25

1 LIST OF EXHIBITS

2 Coalition-11-96 Consumers' Association of Canada
3 (Manitoba) and Winnipeg Harvest
4 (Coalition) to Manitoba Hydro - 1st
5 round of information Requests. Cost
6 of service study - goals - approach
7 to cost causation
8 Coalition-11-97 Consumers' Association of Canada
9 (Manitoba) and Winnipeg Harvest
10 (Coalition) to Manitoba Hydro - 1st
11 round of information Requests. Cost
12 of service study - use of results -
13 comparison of unit costs and rates.
14 Coalition-11-98 Consumers' Association of Canada
15 (Manitoba) and Winnipeg Harvest
16 (Coalition) to Manitoba Hydro - 1st
17 round of information Requests. Cost
18 of service study - transmission and
19 substations - reconciliation of data
20 Coalition-12 Coalition of priority questions -
21 May workshop
22 Coalition-13 Coalition letter to PUB re COSS
23 methodology workshop dated May 10,
24 2016
25

1 LIST OF EXHIBITS

2 Coalition-14	Coalition letter to PUB re COSS evidence dated June 10, 2016
4 Coalition-15	Manitoba Hydro Cost of Service methodology review - evidence prepared by William Harper of Econalysis Consulting Services for Consumers' Association of Canada (Manitoba Branch) and Winnipeg Harvest (The Consumers Coalition)
11 CoW-1	City of Winnipeg's response to PUB's December 8, 2015 letter regarding minimum filing requirements dated December 16, 2015
15 CoW-2	City of Winnipeg Intervenor application
16 CoW-3	Written argument of the City of Winnipeg for the pre-hearing conference - February 10, 2016
19 CoW-4	City of Winnipeg comments re COS model dated February 23, 2016
21 CoW-5	City of Winnipeg Intervenor budget estimate - March 1, 2016
23 CoW-6-1	City of Winnipeg (CoW) to Manitoba Hydro (MH) - 1st Round Information Requests. Direct Assignment - Lighting.

LIST OF EXHIBITS

CoW-6-2	City of Winnipeg (CoW) to Manitoba Hydro (MH) - 1st Round Information Requests. Allocation - customer service.
CoW-6-3	City of Winnipeg (CoW) to Manitoba Hydro (MH) - 1st Round Information Requests. Allocation - customer account - billings
CoW-6-4	City of Winnipeg (CoW) to Manitoba Hydro (MH) - 1st Round Information Requests. Allocation - Distribution plant - lines.
CoW-6-5	City of Winnipeg (CoW) to Manitoba Hydro (MH) - 1st Round Information Requests. Allocation - CP load factor
CoW-6-6	City of Winnipeg (CoW) to Manitoba Hydro (MH) - 1st Round Information Requests. Allocation - class coincident factor
CoW-6-7	City of Winnipeg (CoW) to Manitoba Hydro (MH) - 1st Round Information Requests. Allocation - Hour weighted average price and marginal cost weighting.

LIST OF EXHIBITS

EXHIBIT NO.	DESCRIPTION	PAGE NO.
CoW-6-8	City of Winnipeg (CoW) to Manitoba Hydro (MH) - 1st Round Information Requests. Allocation - energy consumption information	
CoW-6-9	City of Winnipeg (CoW) to Manitoba Hydro (MH) - 1st Round Information Requests. Allocation - Load forecast	
CoW-6-10	City of Winnipeg (CoW) to Manitoba Hydro (MH) - 1st Round Information Requests. Allocation - Load forecast - forecast total kWh	
CoW-7	Ratio of direct to classified costs table - May 13, 2016	
CoW-8	Proposed enhancements of Manitoba Hydro's prospective cost of service study (PCOSS) methodology - evidence prepared by John Todd, President of Elenchus Research Associated Inc. on behalf of the City of Winnipeg.	
GAC-1	Green Action Centre - Intervenor application form	

1 LIST OF EXHIBITS

EXHIBIT NO.	DESCRIPTION	PAGE NO.
GAC-2	2004 PUB testimony and exhibits of Jim Lazar on behalf of Time to Respect Earth's Ecosystems (TREE) and Resource Conservation Manitoba (RCM)	
GAC-3	2006 Evidence of Jim Lazar on behalf of Time to Respect Earth's Ecosystems (TREE) and Resource Conservation Manitoba (RCM) for the Manitoba Hydro Cost of Service Methodology Review - March 15, 2006	
GAC-4	2008 direct testimony of Paul Chernick on behalf of Resource Conservation Manitoba and Time to Respect Earth's Ecosystems - November 17, 2008 - Manitoba Hydro Energy Intensive Industrial Rate application	
GAC-5	2008 direct testimony of Paul Chernick on behalf of Resource Conservation Manitoba and Time to Respect Earth's Ecosystems - February 1, 2008 - Manitoba Hydro 2008/09 General Rate Application	

1 LIST OF EXHIBITS

2 GAC-6	2010 direct testimony of Paul Chernick on behalf of Resource Conservation Manitoba and Time to Respect Earth's Ecosystems - December 10, 2010 - 2010/11 and 2011/12 Manitoba Hydro General Rate Application
8 GAC-7	2012 direct testimony of Paul Chernick on behalf of Green Action Centre - November 16, 2012 - Manitoba Hydro 2011/12 and 2012/13 General Rate Application
13 GAC-8	Green Action Centre - written submission in response to PUB's letter of January 22, 2016 - dated February 10, 2016
17 GAC-9	GAC pre-hearing conference presentation
18 GAC-10	GAC letter to PUB re model dated February 23, 2016
20 GAC-11	GAC proposed budget for COSS - March 1, 2016
22 GAC-12-1	Green Action Centre (GAC) to Manitoba Hydro (MH) - 1st Round Information Requests. Map of MH's transmission system.

LIST OF EXHIBITS

GAC-12-2	Green Action Centre (GAC) to Manitoba Hydro (MH) - 1st Round Information Requests. Split of transmission costs into US interconnections and non-energy related transmission
GAC-12-3	Green Action Centre (GAC) to Manitoba Hydro (MH) - 1st Round Information Requests. Functionalization of the Dorsey converter station
GAC-12-4	Green Action Centre (GAC) to Manitoba Hydro (MH) - 1st Round Information Requests. Transmission - sub-functionalization and allocation of transmission.
GAC-12-5	Green Action Centre (GAC) to Manitoba Hydro (MH) - 1st Round Information Requests. Transmission - sub-functionalization and allocation of transmission.
GAC-12-6	Green Action Centre (GAC) to Manitoba Hydro (MH) - 1st Round Information Requests. Transmission - sub-functionalization and allocation of transmission.

LIST OF EXHIBITS

EXHIBIT NO.	DESCRIPTION	PAGE NO.
GAC-12-7	Green Action Centre (GAC) to Manitoba Hydro (MH) - 1st Round Information Requests. Allocation of transmission.	
GAC-12-8	Green Action Centre (GAC) to Manitoba Hydro (MH) - 1st Round Information Requests. Allocation of transmission.	
GAC-12-9	Green Action Centre (GAC) to Manitoba Hydro (MH) - 1st Round Information Requests. Subtransmission - Allocation of transmission stations.	
GAC-12-10	Green Action Centre (GAC) to Manitoba Hydro (MH) - 1st Round Information Requests. Subtransmission - Allocation of transmission stations.	
GAC-12-11	Green Action Centre (GAC) to Manitoba Hydro (MH) - 1st Round Information Requests. Functionalization of transmission, subtransmission and distribution.	
GAC-12-12	Green Action Centre (GAC) to Manitoba Hydro (MH) - 1st Round Information Requests. Functionalization of Subtransmission.	

LIST OF EXHIBITS

EXHIBIT NO.	DESCRIPTION	PAGE NO.
GAC-12-13	Green Action Centre (GAC) to Manitoba Hydro (MH) - 1st Round Information Requests. Substations - Allocation of substations.	
GAC-12-14	Green Action Centre (GAC) to Manitoba Hydro (MH) - 1st Round Information Requests. Distribution of substations.	
GAC-12-15	Green Action Centre (GAC) to Manitoba Hydro (MH) - 1st Round Information Requests. Allocation of distribution substations.	
GAC-12-16	Green Action Centre (GAC) to Manitoba Hydro (MH) - 1st Round Information Requests. Classification and allocation of distribution lines.	
GAC-12-17	Green Action Centre (GAC) to Manitoba Hydro (MH) - 1st Round Information Requests. Breakdown of distribution plant cost components.	
GAC-12-18	Green Action Centre (GAC) to Manitoba Hydro (MH) - 1st Round Information Requests. Functionalization of distribution	

1 LIST OF EXHIBITS

EXHIBIT NO.	DESCRIPTION	PAGE NO.
GAC-12-19	Green Action Centre (GAC) to Manitoba Hydro (MH) - 1st Round Information Requests. Functionalization and allocation of distribution	
GAC-12-20	Green Action Centre (GAC) to Manitoba Hydro (MH) - 1st Round Information Requests. Allocation of customer costs	
GAC-12-21	Green Action Centre (GAC) to Manitoba Hydro (MH) - 1st Round Information Requests. Weight customer allocators	
GAC-12-22	Green Action Centre (GAC) to Manitoba Hydro (MH) - 1st Round Information Requests. Distribution	
GAC-12-23	Green Action Centre (GAC) to Manitoba Hydro (MH) - 1st Round Information Requests. Classification of distribution.	
GAC-12-24	Green Action Centre (GAC) to Manitoba Hydro (MH) - 1st Round Information Requests. Classification of a portion of distribution as customer-related	

LIST OF EXHIBITS

GAC-12-25	Green Action Centre (GAC) to Manitoba Hydro (MH) - 1st Round Information Requests. Classification of a portion of distribution as customer-related.
GAC-12-26	Green Action Centre (GAC) to Manitoba Hydro (MH) - 1st Round Information Requests. Classification of a portion of distribution as customer-related.
GAC-12-27	Green Action Centre (GAC) to Manitoba Hydro (MH) - 1st Round Information Requests. Classification of a portion of distribution as customer-related.
GAC-12-28	Green Action Centre (GAC) to Manitoba Hydro (MH) - 1st Round Information Requests. Classification of a portion of distribution as customer-related.
GAC-12-29	Green Action Centre (GAC) to Manitoba Hydro (MH) - 1st Round Information Requests. Classification of a portion of distribution as customer-related.
GAC-12-30	Green Action Centre (GAC) to Manitoba Hydro (MH) - 1st Round Information Requests. Classification of a portion of distribution as customer-related.

LIST OF EXHIBITS

GAC-12-31	Green Action Centre (GAC) to Manitoba Hydro (MH) - 1st Round Information Requests. Distribution equipment - serialized equipment.
GAC-12-32	Green Action Centre (GAC) to Manitoba Hydro (MH) - 1st Round Information Requests. Allocation of distribution - appropriateness of 30 percent discount to GSL 0-30 kV class.
GAC-12-33	Green Action Centre (GAC) to Manitoba Hydro (MH) - 1st Round Information Requests. Allocation of distribution - appropriateness of 30 percent discount to GSL 0-30 kV class.
GAC-12-34	Green Action Centre (GAC) to Manitoba Hydro (MH) - 1st Round Information Requests. Allocation of distribution - appropriateness of 30 percent discount to GSL 0-30 kV class.
GAC-12-35	Green Action Centre (GAC) to Manitoba Hydro (MH) - 1st Round Information Requests. Allocation of distribution - appropriateness of 30 percent discount to GSL 0-30 kV class.

LIST OF EXHIBITS

EXHIBIT NO.	DESCRIPTION	PAGE NO.
GAC-12-36	Green Action Centre (GAC) to Manitoba Hydro (MH) - 1st Round Information Requests. Allocation of distribution - appropriateness of 30 percent discount to GSL 0-30 kV class.	
GAC-12-37	Green Action Centre (GAC) to Manitoba Hydro (MH) - 1st Round Information Requests. Classification and allocation of distribution.	
GAC-12-38	Green Action Centre (GAC) to Manitoba Hydro (MH) - 1st Round Information Requests. Distribution functionalization, classification and allocation	
GAC-12-39	Green Action Centre (GAC) to Manitoba Hydro (MH) - 1st Round Information Requests. Circuit maps for all MH distribution circuits.	
GAC-12-40	Green Action Centre (GAC) to Manitoba Hydro (MH) - 1st Round Information Requests. Distribution, classification and allocation	

LIST OF EXHIBITS

GAC-12-41	Green Action Centre (GAC) to Manitoba Hydro (MH) - 1st Round Information Requests. Distribution, classification and allocation
GAC-12-42	Green Action Centre (GAC) to Manitoba Hydro (MH) - 1st Round Information Requests. Distribution, classification and allocation
GAC-12-43	Green Action Centre (GAC) to Manitoba Hydro (MH) - 1st Round Information Requests. Distribution, classification and allocation
GAC-12-44	Green Action Centre (GAC) to Manitoba Hydro (MH) - 1st Round Information Requests. Allocation of line transformers
GAC-12-45	Green Action Centre (GAC) to Manitoba Hydro (MH) - 1st Round Information Requests. Diversity of load on line transformers
GAC-12-46	Green Action Centre (GAC) to Manitoba Hydro (MH) - 1st Round Information Requests. Diversity of load on line transformers

LIST OF EXHIBITS

GAC-12-47	Green Action Centre (GAC) to Manitoba Hydro (MH) - 1st Round Information Requests. Weighted customer allocators for services.
GAC-12-48	Green Action Centre (GAC) to Manitoba Hydro (MH) - 1st Round Information Requests. Weighted customer allocators for services.
GAC-12-49	Green Action Centre (GAC) to Manitoba Hydro (MH) - 1st Round Information Requests. Weighted customer allocators for services.
GAC-12-50	Green Action Centre (GAC) to Manitoba Hydro (MH) - 1st Round Information Requests. Weighted customer allocators for services.
GAC-12-51	Green Action Centre (GAC) to Manitoba Hydro (MH) - 1st Round Information Requests. Weighted customer allocators for services.
GAC-12-52	Green Action Centre (GAC) to Manitoba Hydro (MH) - 1st Round Information Requests. Weighted customer allocators for services.

LIST OF EXHIBITS

EXHIBIT NO.	DESCRIPTION	PAGE NO.
GAC-12-53	Green Action Centre (GAC) to Manitoba Hydro (MH) - 1st Round Information Requests. Weighted energy allocator.	
GAC-12-54	Green Action Centre (GAC) to Manitoba Hydro (MH) - 1st Round Information Requests. Weighted energy allocator.	
GAC-12-55	Green Action Centre (GAC) to Manitoba Hydro (MH) - 1st Round Information Requests. Weighted energy allocator.	
GAC-12-56	Green Action Centre (GAC) to Manitoba Hydro (MH) - 1st Round Information Requests. Weighted energy allocator.	
GAC-12-57	Green Action Centre (GAC) to Manitoba Hydro (MH) - 1st Round Information Requests. Development of class loads.	
GAC-12-58	Green Action Centre (GAC) to Manitoba Hydro (MH) - 1st Round Information Requests. Development of class loads.	
GAC-12-59	Green Action Centre (GAC) to Manitoba Hydro (MH) - 1st Round Information Requests. Development of class loads.	

1 LIST OF EXHIBITS

EXHIBIT NO.	DESCRIPTION	PAGE NO.
GAC-12-60	Green Action Centre (GAC) to Manitoba Hydro (MH) - 1st Round Information Requests. Development of NCP allocator.	
GAC-12-61	Green Action Centre (GAC) to Manitoba Hydro (MH) - 1st Round Information Requests. Development of NCP allocator.	
GAC-13	Evidence of Paul Chernick of Resource Insight Inc. on behalf of the Green Action Centre - June 10, 2016	
GSS/GSM-1	Intervenor request form	
GSS/GSM-2	GSS/GSM budget estimate - March 1, 2016	
GSS/GSM-3	GSS/GSM to PUB re pre-asks dated May 9, 2016	
GSS/GSM-4-1	GSS/GSM Pre-Ask 1. Treatment of exports and net export revenues.	
GSS/GSM-4-2	GSS/GSM Pre-Ask 2. Revenue cost coverage - zone of reasonableness	
GSS/GSM-4-3	GSS/GSM Pre-Ask 3. Cost allocation amendments - export and general service cost allocation	
GSS/GSM-4-4	GSS/GSM Pre-Ask 4. Cost allocation - appropriateness of cost coverage considering MH's load forecast	

1 LIST OF EXHIBITS

2 EXHIBIT NO. DESCRIPTION PAGE NO.

3 GSS/GSM-4-5 GSS/GSM Pre-Ask 5. Hourly load profile

4 GSS/GSM-4-6 GSS/GSM Pre-Ask 6. Generation - hourly

5 load profile.

6 GSS/GSM-4-7 GSS/GSM Pre-Ask 7. Generalization -

7 functionalization

8 GSS/GSM-4-8 GSS/GSM Pre-Ask 8. Exports -

9 historical and forecast breakdown of

10 exports.

11 GSS/GSM-4-9 GSS/GSM Pre-Ask 9. Exports -

12 opportunity export trading desk and

13 MISO membership costs

14 GSS/GSM-4-10 GSS/GSM Pre-Ask 10. Treatment of

15 exports and net export revenues -

16 opportunity export costs.

17 GSS/GSM-4-11 GSS/GSM Pre-Ask 11. Distribution and

18 any other issues.

19 GSS/GSM-5 GSS/GSM letter to PUB re Cost of

20 Service methodology workshop - May 10,

21 2016

22 GSS/GSM-6 GSS/GSM letter to PUB re Intervenor

23 evidence dated June 10, 2016

24

25

1 LIST OF EXHIBITS

2 EXHIBIT NO. DESCRIPTION PAGE NO.

3 MIPUG-1 MIPUG to PUB letter dated December 16,
4 2015 re minium filing requirements for
5 Cost of Service Review
6 MIPUG-2 MIPUG Intervenor application
7 MIPUG-3 MIPUG's previous COSS evidence - cover
8 letter dated February 5, 2016
9 MIPUG-4 Pre-filed testimony of P. Bowman and A.
10 McLaren on behalf of MIPUG in regard to
11 Manitoba Hydro 2006 Cost-of-Service
12 Application.
13 MIPUG-5 Pre-filed testimony of P. Bowman and A.
14 McLaren on behalf of MIPUG in regard to
15 Manitoba Hydro 2008 Cost-of-Service
16 Application.
17 MIPUG-6 Pre-filed testimony of P. Bowman and A.
18 McLaren on behalf of MIPUG in regard to
19 Manitoba Hydro 2010/11 and 2011/12
20 General Rate Application.
21 MIPUG-7 MIPUG's written submission in response
22 to PUB's letter of January 22, 2016 -
23 dated February 10, 2016
24 MIPUG-8 MIPUG comments on MH COS model - dated
25 February 23, 2016

LIST OF EXHIBITS

MIPUG-9	MIPUG's budget estimates for COSS
MIPUG-10-1	Manitoba Industrial Power Users Group (MIPUG) to Manitoba Hydro (MH) - 1st Round of Information Requests. Order 116/08 methodology
MIPUG-10-2	Manitoba Industrial Power Users Group (MIPUG) to Manitoba Hydro (MH) - 1st Round of Information Requests. US interface Cost allocation - transmission cost allocation.
MIPUG-10-3	Manitoba Industrial Power Users Group (MIPUG) to Manitoba Hydro (MH) - 1st Round of Information Requests. 2CP (coincident peak) allocator - D14
MIPUG-10-4	Manitoba Industrial Power Users Group (MIPUG) to Manitoba Hydro (MH) - 1st Round of Information Requests. Allocator C10 - Customer Service general
MIPUG-10-5	Manitoba Industrial Power Users Group (MIPUG) to Manitoba Hydro (MH) - 1st Round of Information Requests. Tabular progression for prospective cost of service study 2006 to 2014

LIST OF EXHIBITS

EXHIBIT NO.	DESCRIPTION	PAGE NO.
MIPUG-10-6	Manitoba Industrial Power Users Group (MIPUG) to Manitoba Hydro (MH) - 1st Round of Information Requests. Export NER	
MIPUG-10-7	Manitoba Industrial Power Users Group (MIPUG) to Manitoba Hydro (MH) - 1st Round of Information Requests. Calculation of top 50 hourly peaks	
MIPUG-10-8	Manitoba Industrial Power Users Group (MIPUG) to Manitoba Hydro (MH) - 1st Round of Information Requests. Electronic models for MIPUT MFRs.	
MIPUG-10-9	Manitoba Industrial Power Users Group (MIPUG) to Manitoba Hydro (MH) - 1st Round of Information Requests. Generation and Transmission costs - scope of costs included in each allocator.	
MIPUG-10-10	Manitoba Industrial Power Users Group (MIPUG) to Manitoba Hydro (MH) - 1st Round of Information Requests. Allocation of some costs of generation to peak useage.	

LIST OF EXHIBITS

EXHIBIT NO.	DESCRIPTION	PAGE NO.
MIPUG-10-11	Manitoba Industrial Power Users Group (MIPUG) to Manitoba Hydro (MH) - 1st Round of Information Requests. Uniform rates.	
MIPUG-10-12	Manitoba Industrial Power Users Group (MIPUG) to Manitoba Hydro (MH) - 1st Round of Information Requests. High customers weightings to industrial customers.	
MIPUG-10-13	Manitoba Industrial Power Users Group (MIPUG) to Manitoba Hydro (MH) - 1st Round of Information Requests. System extension - charges to industrial customer expansions	
MIPUG-10-14	Manitoba Industrial Power Users Group (MIPUG) to Manitoba Hydro (MH) - 1st Round of Information Requests. PCOSS 13	
MIPUG-10-15	Manitoba Industrial Power Users Group (MIPUG) to Manitoba Hydro (MH) - 1st Round of Information Requests. Christensen Report 2012	

LIST OF EXHIBITS

EXHIBIT NO.	DESCRIPTION	PAGE NO.
MIPUG-10-16	Manitoba Industrial Power Users Group (MIPUG) to Manitoba Hydro (MH) - 1st Round of Information Requests. Curtailable service program costs - DSM and demand allocators.	
MIPUG-10-17	Manitoba Industrial Power Users Group (MIPUG) to Manitoba Hydro (MH) - 1st Round of Information Requests. 2012 load research at generation peak for PCOSS14 model.	
MIPUG-10-18	Manitoba Industrial Power Users Group (MIPUG) to Manitoba Hydro (MH) - 1st Round of Information Requests. Derivation of energy weights for PCOSS14	
MIPUG-11	Prefiled testimony of Patrick Bowman in regard to Manitoba Hydro 2016 Cost of Service application submitted on behalf of Manitoba Industrial Power Users Group.	
MKO-1	MKO Intervenor application	
MKO-2	MKO comments on COS model dated February 23, 2016	

1 LIST OF EXHIBITS

	EXHIBIT NO.	DESCRIPTION	PAGE NO.
3	MKO-3	MKO budget for COSS - March 1, 2016	
4	MMF-1	Intervenor request form	
5	MMF-2	COSS MMF budget - March 1, 2016	
6	MIPUG-12	Email dated June 10, 2016, sent at	
7		11:00 a.m.	89
8	MIPUG-13	Patrick Bowman's presentation	91
9	COALITION-16:	ACRONYM LIST	343
10	COALITION-17:	Mr. Harper's presentation	344

11
12
13
14
15
16
17
18
19
20
21
22
23
24
25

1 LIST OF UNDERTAKINGS

NO.	DESCRIPTION	PAGE NO.
31	MIPUG to provide the graph from chapter 13 of the NFAT business case, and comment on it	183
32	MIPUG to explain what the options are for dealing with a negative net export revenue either through the revenue requirement or through a draw down of the surplus account	287
33	MIPUG to provide list of Manitoba Hydro changes in methodology from previous Cost of Service Studies, and indicate where MIPUG agrees or disagrees	372

1 --- Upon commencing at 9:01 a.m.

2

3 THE FACILITATOR: Good morning,

4 everyone. My name's Bill Grant, for anyone who wasn't

5 at the last set of workshops. We have a few opening

6 issues to deal with, and the -- first of all is to

7 turn it over to the -- the Chairperson of the Board.

8 BOARD MEMBER GOSSELIN: Bonjour.

9 Before we get started, you'll note a new person in the

10 -- in the member -- the panel member session. When

11 Manitoba Hydro initially filed its cost-of-service

12 materials, the Board designated a four (4) person

13 panel to hear the matter.

14 The panel consisted of myself, Board

15 member Marilyn Kapitany at the end, Hugh Grant, and

16 the -- the fourth person was Rick Bell. Mr. Bell was

17 previously involved in the NFAT review, as some of you

18 will recall, as well as the last Manitoba Hydro

19 General Rate Application.

20 He unfortunately is no longer a member

21 of the Public Utilities Board. However, the

22 provincial government recently appointed three (3) new

23 members to the Board. It is the Board's intention

24 that the cost of -- that one (1) of the new

25 appointees, Mr. Larry Ring beside me, fill Mr. Bell's

1 role in the cost-of-service review.

2 The Board canvassed all the parties

3 involved in the hearing, including Manitoba Hydro, and

4 everyone has consented to his -- to this replacement.

5 So welcome to the panel. Welcome, Larry. Hope you

6 enjoy the process.

7 With that, I would like to welcome you

8 to the cost-of-service panel, and we'll turn the

9 microphone over to Bill to facilitate today's

10 workshop. Thanks, Bill.

11 THE FACILITATOR: All right. Thank

12 you, Reg.

13 Next in the -- the sort of preliminary

14 items was Antoine. I believe that you wanted to enter

15 an exhibit?

16 MR. ANTOINE HACAULT: That can be done

17 when we start the evidence or just before, Mr. Grant.

18 That's up to you.

19 THE FACILITATOR: All right. Last of

20 all, before we turn back to that, then, I guess, will

21 be one that -- that Sean has berated me already for

22 the poor effort I did in the last rounds of making

23 sure that, when people are asking undertakings, that

24 they identify it as an undertaking and explain it

25 clearly.

1 As I understand it, the typists that
2 are pre -- preparing the transcript will then identify
3 it as an undertaking and highlight it that way. So
4 that should be helpful to us as we get going.
5 Are there any other preliminary items
6 from anyone before we move forward? Yes?
7 MR. BILL GANGE: Mr. Grant, beside me
8 is David Cordingley. David is a lawyer at my law
9 firm. I will not be able to be here tomorrow, and so
10 Mr. Cordingley will be here in my place during Mr.
11 Chernick's testimony. And so Mr. Cordingley will be
12 taking over for -- for tomorrow.
13 THE FACILITATOR: Sounds great.
14 Anything else?
15
16 (BRIEF PAUSE)
17
18 THE FACILITATOR: No? If not, then
19 over to you, Antoine and Patrick. I look forward to
20 the presentation.
21 MR. ANTOINE HACAULT: Thank you very
22 much, Mr. Grant. And I'd like to start this morning
23 by welcoming Mr. Larry Ring on behalf of the
24 Industrial Consumers on behalf of Intergroup, the
25 consultants who will be presenting this morning. To

1 my left is Patrick Bowman, and behind me is Melissa
2 Davis. She also has somebody new with her.
3 Mr. Grant, you had circulated, and we
4 thank you for that, a draft agenda with a request on
5 commentary with respect to the presentations. And it
6 included a number of things, in -- including
7 identification of issues where there was agreement or
8 disagreement between the parties. And that prompted
9 an email from myself and some thought as to what we
10 were initially asked to try and achieve through these
11 workshops.
12 And I've provided a copy of the email
13 that I had circulated to all counsel. It was an email
14 dated June 10, 2016, sent at 11:00 a.m. And with the
15 permission of all parties, we'd have that marked as
16 MIPUG-12.
17
18 --- EXHIBIT NO. MIPUG-12: Email dated June 10, 2016,
19 sent at 11:00 a.m.
20
21 MR. ANTOINE HACAULT: The reason for
22 providing that, and I may have been totally off base,
23 but it appeared to me in observing some of the Board
24 members during the last process that there was some
25 look in the faces that, well, what's happening here

1 and -- and why aren't we hearing more about, you know,
2 the different positions and things like this?
3 And my understanding of this new
4 process was that the series of workshops were intended
5 essentially to take over the role of a discovery, and
6 the chance to ask questions in a written form. And
7 unfortunately, that process is sometimes pretty
8 disconnected as to really communicating in an
9 efficient and proper way the different positions of
10 the parties, because you have limited time to ask
11 questions on specific issues.
12 So I -- we had been preparing our case
13 on the basis that it was a discovery process, as
14 ordered by the Board. And we apologize if it's turned
15 into something that the Board sees a little bit less
16 useful than it expected, but we're trying to do the
17 best we can with the new process. And I've finished
18 the end of the email by saying that we look forward to
19 completing the process, and making sure that the Board
20 gets the information in a way that it wants to get it.
21 Everybody has had the chance now to
22 file their written evidence. So I think the positions
23 are starting to crystalize, and we'll maybe see a bit
24 more of that as the crystallization and understanding
25 the issues, but I thank you very much, and this is why

1 I had raised the issues in my email, and that's why
2 I'm marking it.
3 The next document which I'd like to
4 have marked as an exhibit would be the presentation
5 which Mr. Bowman will be making this morning, and my
6 understanding would be that this would be entered as
7 MIPUG-13.
8
9 --- EXHIBIT NO. MIPUG-13: Patrick Bowman's
10 presentation
11
12 MR. ANTOINE HACAULT: It -- it's not
13 my intention, although there was the CV of Mr. Bowman
14 attached to his evidence, to go through the
15 qualification process. I understood that that wasn't
16 part of what we would be doing this morning.
17 Mr. Bowman will do his best to give a
18 high-level overview of his written evidence, and then
19 he'll receive any questions that may be asked of other
20 parties to clarify his evidence, or as -- as we said,
21 to take over the -- the role of interrogatories which
22 would have occurred in a written format.
23 With that general introduction, I would
24 ask if Mr. Bowman can now start his presentation.
25 THE FACILITATOR: Patrick, I

1 understand you get the opportunity to be sworn in now.
2
3 MIPUB PANEL:
4 PATRICK BOWMAN, Sworn
5
6 PRESENTATION BY MIPUG:
7 MR. PATRICK BOWMAN: Good morning.
8 Thank you. This morning, I'll be speaking to the
9 exhibit that is on the screen which has been marked at
10 MIPUG-13. This is a summary presentation of the pre-
11 filed testimony which is marked as MIPUG-11.
12 It only focusses on the high level
13 conclusions. I believe it addresses the primary items
14 that were in the scope for today with possibly the
15 exception of doing an itemized list about where this
16 evidence or -- or the -- the positions I've taken
17 agree with Hydro on -- on all of the different
18 proposals they have made as compared to past PUB
19 orders. And I'm happy to go through that. I have
20 that on the side. I just haven't included it.
21 Turning to the second page of this --
22 in this cost of service review, much like when we
23 would do this assignment for -- in -- in any
24 jurisdiction, we have looked at the Cost of Service
25 Study, focussed on cost causation principles, focussed

1 on issues of typical concern to industrials. That
2 means that you won't see any comments in here about
3 normal matters of distribution, for example. That's
4 not an -- an item where the industrials ask us to
5 focus our attention.
6 The majority of the items relate to the
7 -- the bulk power system as well as the principles
8 should underline a -- a cost of service study. And at
9 a high level comment, in -- in general, Hydro's Cost
10 of Service Study methods are -- largely are industry
11 standard and reasonably represent the system that
12 Hydro has in place.
13 In some areas, through, Hydro is
14 outside the norm, if not well outside the norm, and is
15 proposing methods that aren't necessarily consistent,
16 in my view, with the underlying system economics and
17 with the past PUB determinations. And as a result of
18 that, there ends up being ten (10) recommendations.
19 And on the next slide, I focus on the
20 fact that, in terms of cost causation, these are words
21 that are very commonly used for a cost of service
22 study. It is the underlying principle. In -- in most
23 cases, just the -- the definition or the term 'cost
24 causation' gives one enough guidance to be able to
25 make some determinations.

1 In Hydro's case, there are some
2 complexities that mean that the -- the evidence you'll
3 find spends some additional time compared to normal on
4 the underlying principles behind cost causation in
5 order to try to get to the -- the root of how to apply
6 this -- these concepts.
7 I highlight here that there are at
8 least three (3) items that really stand out in terms
9 of Hydro's Cost of Service Study that are not
10 necessarily huge factors in a lot of utilities. And I
11 think that this underlines why they're -- they -- they
12 need to go to first principles in -- in looking at
13 cost causation.
14 One (1) of them is in -- why were
15 specific assets built. And we'll hear very different
16 stories from different parties about Hydro's -- a lot
17 of Hydro's major investment, the issues of the export
18 business cases, how the exports fit into the decision
19 to built an asset, or the decision of which asset to
20 choose.
21 That is not necessarily common in
22 jurisdictions that have regulated cost of service cost
23 based rates applied to generation and transmission, so
24 that is one (1) that is a -- a reason why, looking to
25 cost causation principles, requires a -- a bit more of

1 the academic-y, if I can call it that, side of -- of
2 understanding what -- what 'cost causation' means.
3 The second is the Hydro's system in a -
4 - the test year runs a cost of service study with one
5 (1) series of numbers representing one (1) way that
6 the system could look. But we know that the water
7 flows could be materially different than that. If the
8 water flows are different, the system assets will be
9 used in a different way, and so the question of use in
10 the Cost of Service Study becomes important.
11 Am I supposed to be looking at the use
12 of the assets as they're used in the year that we're
13 modelling, or am I supposed to be looking at the use
14 of the assets over all the different years, or, you
15 know. So that -- that's another reason why the -- the
16 Cost of Service Study is a little bit more complicated
17 than many utilities.
18 And the third is that Hydro sets out
19 its objectives for the Cost of Service Study, which
20 are in -- in my experience and my opinion, overly
21 broad. They include a number of -- a -- a number of
22 objectives which are appropriately addressed in other
23 steps of the rate-setting process, not in the Cost of
24 Service Study, and so it ends up burdening the study
25 with trying to -- trying to meet too many competing

1 objectives rather than just trying to get down to the
2 meat of measuring what does it cost to produce that
3 kilowatt hour, or that peak demand, or that -- serve
4 that customer.
5 So for those three (3) reasons, the
6 cost causation that's a well-established practice
7 needs to be thought about in a little more detail to
8 get through Hydro.
9
10 (BRIEF PAUSE)
11
12 MR. PATRICK BOWMAN: So I emphasize in
13 this slide that in preparing the pre-filed testimony,
14 I saw a need to elaborate on the core principles
15 behind just the term 'cost causation'. This is all
16 done in Section 2 of the -- of the pre-filed
17 testimony, which is not very long, but it is -- it
18 goes through a number of the -- the principles.
19 In general, though, just saying the
20 words 'cost causation' and trying to think about it at
21 a -- at a basic level can lead to some confusion over
22 such matters as what was an asset built for versus is
23 was it used for. Sometimes those two (2) things are
24 different. Which one are we supposed to be trying to
25 capture?

We -- I -- I ended up trying to drag to a concept that I've used the term 'economic identity' of an asset. It's the closest I could come to representing the idea that each -- each asset on the system has a role.

That role could be dependent on -- on different factors of how it fits in and -- and getting at the root of -- of that mixture of what it was built for, why it's maintained, what drives costs, what type of uses drive the cost, and -- and what is it used for. Somehow in that bundle, how does one capture this concept of the -- the economic identity of the cost.

And there's some examples in Section 2. You'll find where I go through of -- good cost of service practice from other places, sometimes from Hydro study which, for example, sometimes one (1) would look at an asset of what it's built for and -- and it -- specifically ignore what it's used for in terms of coming up with the proper cost of service method.

In other cases you'd ignore what it's built for and look at what it's used for. And it really comes down to getting behind this -- this simple snapshot of -- of one (1) given year.

1 And a danger that I see arising that is
2 probably a bigger deal for Manitoba Hydro than a lot
3 is that the operational realities of the system, the
4 ope -- the day-to-day decision-making, the -- the
5 function from millisecond to millisecond can become a
6 -- a tempting thing to jump to.
7 We had some comments about things like
8 transmission systems that react instantly. And I
9 think that is a -- it's -- it's tempting, but it can
10 lead to incorrect answers about looking at what is the
11 -- what is the economic nature of that investment.
12 I'm trying to move a little bit quickly
13 here. We don't have a tonne of time. Yeah. So we're
14 now into slide 5, where I'm noting there are ten (10)
15 recommendations as I had set out. I only intend to go
16 through five (5) of those in any detail today.
17 The other five (5) are listed there in
18 the blue section of this slide. Very briefly, the --
19 they're -- one (1) of the ones I won't go through is
20 the US interconnections. I think it's a fairly
21 straightforward item. Another one I won't go through
22 is the customer service costs. This one, we have a
23 concern about that there hasn't been enough evidence
24 to persuade us. We intend to pursue it further.
25 Two (2) rounds of questioning have led

1 to a bit of a -- a circular description of, these are
2 customer services and they're a substantial amount of
3 money in -- in the -- in -- tied up in them and -- and
4 the justification isn't there. So I don't have a -- I
5 don't intend to spend a lot of time on that one today
6 unless people want to ask questions.
7 A third one (1) I -- I didn't intend to
8 spend a lot of time on is DSM costs for energy
9 programs. This is a item that Hydro has proposed a
10 method that we agree with. It's a method that we
11 agree with in past evidence when Hydro has -- has
12 discussed it before and it's -- there's a fair bit of
13 discussion in the -- in our submission in -- in my
14 pre-filed testimony on that.
15 The number 8 there, Curtail Rate
16 Program, I -- I think it's a simple issue. It's a
17 mismatch in the Cost of Service Study. I don't think
18 there's a -- a lot of benefit in going through that
19 further this morning.
20 And the last is the policy-related
21 adjustments which are relatively clear issues with
22 some different positions. And that's a question of
23 whether, if you have leftover export dollars, do you
24 first allocate them to certain policy items that have
25 no linkage to the -- the cost?

1 It's nothing about serving exports, but
2 it's -- it's items that have been assigned against --
3 against exports in the past. And in my view, if
4 you're going to have a defensible Cost of Service
5 Study that's trying to measure the costs, you don't
6 get into throwing in these odd policy recommendations.
7 And that applies to uniform rates. It
8 applies somewhat to the Affordable Energy Fund,
9 although there's a bit of a different story on that
10 one. But those are the five (5) that I didn't inspend
11 -- intend to spend time on.
12 So into the recommendations.
13 Recommendation 1 is not a method, per se. It is an
14 overall principle, and it is -- as -- as I addressed,
15 it's impor -- it's necessary in this Cost of Service
16 Study to produce a defensible result that's useful for
17 -- for rate setting, and that's useful for
18 understanding where different customer classes fit in
19 terms of the costs that they're paying to have a Cost
20 of Service Study that is principled, that isn't tied
21 up with these different policy items, that is
22 focussing on cost causation principles.
23 Those other items can be dealt with in
24 rate design if they're needed. And Section 2 of the
25 evidence goes through that one in -- in a fair bit of

1 detail.

2 The second item is that, in terms of

3 generation costs, you'll recall that in a cost of

4 service study, we will classically go through three

5 (3) steps, one (1) that's called functionalization to

6 figure out for our cost -- what -- what function does

7 it play on the -- on the grid. Is a generation asset,

8 is it a transmission asset?

9 The second step is a -- a

10 classification step where you look at that cost and

11 you say, What type of -- of uses should be -- that --

12 that cost be allocated to? And the -- the -- a

13 classic breakdown for generation is either a use of

14 energy or a use of peak capacity.

15 And -- and most generation has a role

16 in -- in supporting both of those things, energy and

17 capacity being different uses of the system and having

18 different distribution among the customer classes.

19 Manitoba Hydro is -- is very unique.

20 As a matter of fact, they may be one (1) of the only

21 examples out there where they classify 100 percent of

22 generation costs to energy.

23 Now, Hydro's case is that, having

24 classified 100 percent of the generation costs to

25 energy, they then go through a step in the subsequent

1 step of cost of service, the -- the allocation step,
2 to allocate it in a way that -- that sort of creeps
3 back in the concept of capacity.
4 And -- and that's something I disagree
5 with. I think the way that they treat energy in the
6 allocation step is an appropriate way to treat energy
7 -- that is, recognizing that energy -- a kilowatt hour
8 used at different times throughout the year has a
9 different importance to the system.
10 They weight that by marginal cost to
11 come up with those weightings. That is reasonable to
12 me. To -- the marginal cost approach that they use is
13 directionally appropriate. It may not be perfect, but
14 it's reasonable and it's -- it's easily implemented
15 compared to alternatives.
16 And that marginal cost approach is
17 appropriate for assets like wind, for example, which
18 have no capacity whatsoever. You can't guarantee
19 they're going to generate peak. Hydro doesn't ascribe
20 them any capacity in its planning. That -- the
21 marginal cost-weighted energy, 100 percent energy, is
22 an appropriate way to consider wind.
23 Everything else on Hydro's system other
24 than wind has both an energy and a capacity component
25 to it. And if you look in Hydro's planning tables,

1 you'll find both energy and capacity tracked. Hydro
2 will plan its system so that it can meet both of
3 those. It will incur costs to meet both of those, and
4 as a result, capacity should be explicitly recognized
5 in the generation classification.
6 And as I said, probably 99.9 percent of
7 utilities do that, and -- and some in -- in much more
8 substantial ways than -- than even I would be
9 suggesting here. For many thermal utilities, all of
10 their investment in plants, like coal plants and --
11 and gas plants, can end up as -- as capacity demand
12 classified costs.
13 So in Hydro's case, this current
14 Application starts with classified 100 percent energy.
15 It then takes that energy and assign -- allocates it
16 based on a marginal cost weighted -- a twelve (12)
17 period weighting. Hydro has adjusted those marginal
18 cost weightings in this hearing to try to pick up what
19 it considers to be a bit more of a capacity signal.
20 The way they've done that is -- is
21 ineffective. A capacity signal is about the highest
22 hours of the year. The absolute peaks, the -- the
23 most critical times on the system when everything has
24 to be working right and the system really has to be
25 performing its peak, the Hydro tries to weight those

1 hours it effectively says two thousand (2,000) hours
2 of the year are equally important, and we absolutely
3 know that's not the case.
4 So this -- the weighting that they've
5 put in that's a quarter of the year, two thousand
6 (2,000) hours of the eight thousand seven hundred and
7 sixty (8,760). The weightings that they've put in
8 just as a tool are -- are excessively -- excessively
9 blunt.
10 They're -- they're not moving in the
11 right direction and includes things like, you know,
12 middle of the day in spring when loads are low. It
13 considers those at hours that get extra capacity
14 weighting which is not consistent with COSS drivers.
15 Even if you were to focus only on the
16 winter peak period of the weighting, that still picks
17 up six hundred and sixty-one (661) hours of the year,
18 which is much too coarse. This can be easily solved
19 by taking your generation costs and splitting it the
20 way that most peop -- most utilities to into a portion
21 that assigned based on peak or capacity and a portion
22 assigned based on energy.
23 I go through some options in my
24 evidence for how that could be done. I say that --
25 the -- Hydro hasn't done a lot of assessment of

1 options. I -- I haven't taken the time with the data
2 to try to do a major assessment of that, but based on
3 a number of different approaches you're probably
4 talking about a capacity weighting in the range of 21
5 to 23 percent.
6 I think for the purposes of this --
7 this hearing, concluding that it should be in that
8 range and having Hydro be sent off to do some more
9 work on refining that is -- is reasonable. And the
10 remaining generation, which is the remaining almost 80
11 percent, can continue to be done on the marginal cost
12 weighted energy.
13 I wouldn't bother with the extra
14 capacity adder they put in. As I said, it's -- it's
15 way to coarse a signal. I'm not sure it captures very
16 much of anything.
17
18 (BRIEF PAUSE)
19
20 MR. PATRICK BOWMAN: For the portion
21 that is classified to demand, it should be focused on
22 winter demand. That is the one (1) that Hydro models
23 in its -- in its system planning tables. Winter is
24 when the domestic system peaks at its highest. That's
25 when everything that's to be work -- working at its --

1 at its best on the generation side.

2 And I -- I quote it as 1 CP but you

3 have to remember that Hydro's definition of 1 CP is a

4 little bit different than much of the industry.

5 Hydro's definition of 1 CP in its cost of service is

6 actually more like -- more like fifty (50) hours -- an

7 average across fifty (50) peak hours spread across

8 about three (3) months.

9 Most people who spread their peak that

10 they're averaging across three (3) months would call

11 it more like 3 CP, not 1 CP, but nonetheless the point

12 being the winter -- the winter peak hours.

13 BOARD MEMBER GOSSELIN: Mr. Bowman, I

14 have a question. I'm sorry, could you go back to

15 number one (1)?

16 MR. PATRICK BOWMAN: Yeah.

17 BOARD MEMBER GOSSELIN: And could you

18 -- could you focus on economic identity of each cost

19 item, please?

20 MR. PATRICK BOWMAN: Yes. I give some

21 examples in Section 2 of the -- of the pre-filed

22 testimony but when you get down to given assets you --

23 one might look at it and say, you know, what -- what

24 is it planned for and what is it used for? What

25 drives the costs of the investment in the first place,

1 and what kilowatt hours -- who is using the kilowatt
2 hours that it -- it produces?
3 And those are -- are two (2) classic
4 cost of service methods. There are -- there are
5 actually some others that -- that people look at in
6 terms of coming up with this concept of cost
7 causation. But in the -- in the pre-filed testimony
8 at -- at Section 2.3 I go through some examples of --
9 of different assets, both here and elsewhere, that
10 capture the idea that you -- you won't always look at
11 use, or you won't always look at the basis for
12 investment in -- in the first place to come up with
13 the -- the appropriate way to treat an asset in -- in
14 a cost of service study.
15 So one (1) example I go through there
16 is -- is an asset in -- in Yukon territory. And in
17 Yukon there is an older hydro plant from the '50s on
18 the Yukon River. This is in section 2.3 at the bottom
19 of page 13 if someone wanted to track.
20 So there's an older hydro plant on the
21 Yukon River. In Yukon, the period of time that
22 matters for peak, for capacity, is -- is wintertime.
23 Of course they have electric heating. Their -- their
24 winter loads are much higher. They're not
25 interconnected. And in the wintertime, the river

1 flows are quite a bit lower.

2 So they had three (3) hydro units

3 installed in the river. It could use all of the water

4 in winter, but it couldn't use the water in the

5 summer. There's more water in the summer than those

6 three (3) units could use.

7 And so in about the 1980s they

8 installed a fourth unit. The economic rationale for

9 that fourth unit was capturing that summer flow,

10 right? And so the benefit that fourth unit brought

11 was extra energy in the summer. It didn't do anything

12 about helping meet the winter peak.

13 So the basis for investment is not

14 about peak demand, it's only about energy. And as a

15 result, the cost of study in Yukon classifies that

16 asset a hundred percent to energy. If you actually go

17 to look at how Yukon Energy operates its system in any

18 given year, that fourth wheel might be running at peak

19 time. It's often dispatched through much of the

20 winter.

21 Even though it wasn't designed to say I

22 need it for the winter, Units 1, 2, and 3 could have

23 done the job. But the fourth wheel is -- it's

24 available to the operators and they'll dispatch the

25 system however makes sense from hour to hour. But the

1 -- that use -- the fact that it happens to be used in
2 winter -- in winter hours do -- misses the point that
3 the -- the whole basis for investment, the only reason
4 it was built was about summer energy, not about winter
5 peak.
6 So the -- the Utility Board in that
7 example has recognized that that's -- that's an
8 energy-related asset even though it happened to be
9 used at peak.
10 BOARD MEMBER GOSSELIN: So draw --
11 draw a parallel to that example in Manitoba Hydro's
12 case, please.
13 MR. PATRICK BOWMAN: Like, if I want
14 to draw a Manitoba Hydro parallel it might be
15 something like Bipole III, where the existing system
16 has northern generation, It has the bipoles to bring
17 that northern generation down. And we know that those
18 bipoles only exist because of the northern generation
19 and the northern generation only exists because of the
20 bipoles. They're -- they're part and parcel of a plan
21 to draw up the north.
22 They were assessed in a combined way
23 when the -- the project was -- was first brought --
24 brought forward, LWRCRD. They were considered in --
25 as an economic bundle. It required Canada to come in

1 and participate on helping to build and finance the
2 bipoles. Manitoba Hydro couldn't actually get over
3 that hurdle, it was too expensive at the time, and --
4 and that entire complex was built.
5 Along comes Bipole III -- or -- or
6 along -- that system then operated for decades in that
7 -- in that fashion, including adding Long Spruce and
8 Limestone over the years, and Bipoles I and II did the
9 job.
10 Eventually, Manitoba Hydro's load grew.
11 And the load growth, particularly the winter growth,
12 of the domestic customers finally caused the need for
13 Bipole III. And we looked at a graph the last time we
14 were here that showed that if -- if we were still at
15 the loads from the mid-'90s, long after Bipole I and
16 II were in service and long after Long Spruce and that
17 were generating power, we would be fine with Bipole I
18 and II. You only get to the need for a Bipole III
19 because the domestic grew.
20 So if you want to look at -- and -- and
21 by 'domestic load,' mean winter load. The summer
22 load's much lower. If you want -- so if you want to
23 get to the -- the rationale for Bipole III and if you
24 read through the Need and Alternative document for the
25 Clean Environment Commission, the rationale is based

1 on the fact that in -- in winter our peaks have grown
2 and Bipole III was concluded by Hydro to be the best
3 way of suppling that -- that power.
4 It wasn't part of the Keeyask business
5 case. It didn't come here to NFAT. It didn't justify
6 it as an -- as an outlet line for Keeyask. There were
7 outlet lines for Keeyask that were assessed as part of
8 the business case, you'll recall, the Keeyask
9 transmission. This wasn't part of it. This was taken
10 out.
11 And so what is the economic identity of
12 Bipole III? If you get caught up too much in -- well,
13 at any given hour, Hydro will load all three (3)
14 lines, so it'll be used all throughout the year.
15 That's true, just like the White -- unit in
16 Whitehorse, it could be used in any hour of the year.
17 But the driver for the investment was growth in the
18 winter loads in -- in Manitoba. That's why we
19 eventually needed the asset. And it goes to the core
20 of -- of the economic rationale for that asset. So
21 that's a parallel to that -- that example from the
22 Yukon.
23 I had an example -- another example
24 that goes the other for other reasons, which is where
25 you have a focus on what assets are used for and not

1 planned for or -- or neither of the above, like --
2 like Brandon coal, which is on the -- the next page of
3 that document. Brandon coal is effectively not being
4 used in the cost of service study because the cost of
5 service study's based on an average water year. The
6 coal plant is only there pretty much to back up
7 extreme droughts.
8 It's not being used for what it was
9 built for in the '50s. That was an entirely system,
10 what it was built for. It has some different economic
11 identity now on the system. And that different
12 economic identity is basically the insurance. And
13 it's insurance for only domestic customers. It does
14 nothing for exports. We can't export the power. We
15 have a law that says we can't export the power, even
16 though again at a use level you can't say which
17 kilowatt hour went where.
18 The only time you'd be allowed to turn
19 that on and be able to use it consistent with that --
20 that legislation is if there was a severe drought in
21 Manitoba, and as a result only domestic customers
22 should be paying for the Brandon Coal Plant. It
23 shouldn't be allocated to the export class. And
24 that's one (1) of the recommendations in our -- in our
25 -- in the -- the submissions.

1 So, you know, for -- in that case you
2 can't just look to the -- the -- any role that it had
3 a long time ago. You have to look at why it's being
4 maintained. Does that -- does that help?
5 BOARD MEMBER GOSSELIN: It does help.
6 It does help it. I'm -- I'm trying to -- I'm kind of
7 seeing a -- bipole is -- the -- the use of bipole is
8 shifting, but you're saying look at the economic
9 identity when it was first planned, or the decision
10 was made to -- to build it. And yet now you're saying
11 with the Brandon coal plant, over time you're using it
12 for a different use, but you should use the economic
13 identity today as opposed to when it was truly built?
14 MR. PATRICK BOWMAN: Well, in -- in a
15 way, yes. Bipole is -- is just coming into service.
16 It's not even PCOSS14, of course. It's just coming
17 into service early on. You know, twenty (20) years
18 from now if the domestic load has grown to a
19 significant extent and -- and one (1) was to look at
20 the -- the system load across all the seasons and say,
21 you know, But for Bipole III, we couldn't -- we
22 couldn't supply the domestic customers on -- on warm
23 summer evenings, then it might be an asset where you'd
24 say, Yeah, it's got a role that it's playing all year.
25 But I'm -- I'm reasonably certain that

1 over that period Manitoba's load will continue to show
2 a winter peaking shape. That's probably going to be
3 here forever. It's inh -- probably inherent to the
4 way Manitobans use power.
5 There -- that -- that will continue to
6 mean that you have to design the system for its -- its
7 biggest investment and its most robust ability to
8 perform to -- to suit win -- those winter loads and
9 what they drive on the system. And as a result, a
10 subset of costs such as Bipole III should really be
11 targeted towards the winter.
12 Now, I'm not -- you'll -- you'll notice
13 as I go through he I say, Bipole III on that rationale
14 and on -- should probably be a winter -- allocated
15 based on the winter peak -- or classified based on the
16 winter peak, but I've actually accepted that its role
17 is not only about being available in the highest hour
18 of the year.
19 It actually has a role through most of
20 the winter peak and shoulder hours -- peak hours and
21 shoulder hours. Like it's not one (1) hour of winter
22 we needed, it's -- it's six hundred (600) hours of
23 winter we needed if you look at the -- the data Hydro
24 has produced.
25 And so you could look at something

1 broader than just the -- the one (1) peak or the fifty
2 (50) hours. You might go to something like the six
3 hundred (600) or twelve hundred (1,200) hours. But
4 it's really about those winter hours.
5 It's not -- not anything like the --
6 the summer hours that are driving it and -- and it
7 probably never will be.
8
9 (BRIEF PAUSE)
10
11 MR. PATRICK BOWMAN: I think that
12 finishes the -- both 1 and 2. The 3rd comment there
13 is about this concept of what they call generalation -
14 - generation-related transmission, GRTA is a -- a
15 definition sometimes used in -- in some jurisdictions
16 like -- like British Columbia.
17 And as I mentioned somewhat in the
18 discussion we just had, there are -- there are times
19 like the Keeyask plant where Keeyask has got to be
20 built where it's got to be built at the set of rapids
21 on the Nelson River. As a result, it requires
22 transmission to get to -- or req -- requires wires to
23 get to the -- the substation on the grid.
24 Those wires are integral to the Keeyask
25 plant. They'd never have been built with Keeyask.

1 Keeyask never would have been built without the wires.
2 They're part of the business case with Keeyask. And
3 the -- a -- a normal cost of service methodology would
4 say, you can treat those transmission wires, or those
5 wires as a generation asset, because they're, to use
6 the term I've sometimes heard, they're more like a --
7 a driveway than a -- than a highway, if you like.
8 They're the -- the driveway to the
9 plant. So the -- this is -- this is not unheard of.
10 Not everyone uses the concept, but it's not unheard of
11 to use this generation related transmission concept.
12 But it's really should be pretty limited and -- and
13 they're referenced in the -- in the NARUC manuals,
14 there's even references in -- in Christensen's report
15 about this being a -- a fairly limited type of
16 category.
17 To give you an idea, when BC Hydro uses
18 the category, they only use it for some transmission
19 that's north of Williston or east of Nicola which, if
20 you know BC, it's -- it's getting very close to the
21 generating stations. And it ends up being about 5
22 percent of their costs that would otherwise be
23 transmission that gets treated as generation.
24 If you go with the methods Manitoba
25 Hydro is talking about, by the time Bipole III comes

1 in, Manitoba Hydro will have 80 percent of its
2 investment in -- in wires and substations considered
3 to be generation related. It's so far outside the
4 norm, going from five (5) to eighty (80), as an
5 example, that it -- it makes one question overuse of
6 this category.
7 I have some other examples from
8 Newfoundland, too, where they -- where it's about 15
9 percent to energy -- to energy in their case.
10 In order to look at this, the -- the
11 key is that all transmission moves energy. All
12 transmission operates in all hours, effectively all
13 hours. The point is: Why is -- why is the asset
14 built, and is it -- is its identity completely linked
15 to the -- to the generating station?
16 As a result of that -- that test, I say
17 that Bipole III, as I just went through, should --
18 should not be a GRTA. Bipoles I and II meet the test,
19 continue to meet the test as a -- as a generation-
20 related transmission.
21 Probably Hydro's missing a few if it
22 goes through its list like the small outlet lines from
23 Wuskwatim, about 3 million, 3.4 million rate base,
24 should probably be generation-related transmission.
25 The Dorsey converter is one that has --

1 has not been transmit -- treated as generation-related
2 transmission. In this case, Hydro's suggesting it
3 should be. We didn't see the case for it, and that's
4 set out in the evidence.
5 And the last item I intend to spend any
6 time on is on slide 8 -- or the last -- the last two
7 (2) items.
8 BOARD MEMBER GOSSELIN: I'm sorry,
9 could you --
10 MR. PATRICK BOWMAN: Yeah.
11 BOARD MEMBER GOSSELIN: -- could I ask
12 you to go back to -- because --
13 MR. PATRICK BOWMAN: Yes.
14 BOARD MEMBER GOSSELIN: -- the major
15 point of contention here is the Dorsey converter.
16 Could you -- could you give me the Cole's Notes
17 version of why you think this should be treated as a
18 non-GRTA versus Hydro's position?
19 MR. PATRICK BOWMAN: Yes. I'll say,
20 in -- in my opinion, the -- Bipoles I and II pass the
21 test, but the Dorsey converter side is not a slam dunk
22 either way. It's -- it's got reasons why one might
23 want to think about it being related to generation.
24 It's got reasons why one might think about it not
25 being related to generation.

1 And -- and Christensen comes to the
2 same conclusion and actually goes through trying to
3 figure out how much should be each. I -- but I mainly
4 have two (2) reasons why, in that -- against that set
5 of -- of facts, one would not consider it generation
6 related.
7 One is because this is -- should be a
8 limited category. Normally, transmission is
9 transmission. It's only -- it should be a limited
10 category where you have slam dunks being part of
11 generation. If Dorsey's got that much of a debate
12 about it, probably it shouldn't pass the test at a
13 really simple level.
14 And secondly, the -- the more detailed
15 side is what one would really need to look at. And --
16 and I -- I saw Christensen propose some analysis. I
17 would propose a little bit of a different analysis,
18 but the -- the crux of -- of the Dorsey converter
19 issue goes back.
20 Hydro explained it well in about 2001
21 when they adopted it as the Dorsey converter
22 transmission, and they proposed that and the Board
23 accepted it. It goes to the fact that the nature of
24 the DC transmission means that you can make a lot less
25 investment in the AC system and still have it work.

1 So this -- this asset, although it's
2 converting DC to AC, in the process it's saving you
3 significant investment on the AC transmission side of
4 different type of equipment that would be required.
5 And that's -- like I said, Hydro came
6 up with that rationale in 2001/2002, in the hearing
7 that we had here. And we supported it then, and --
8 and they continue with that through 2006 and 2008, and
9 for the same reasons.
10 Now, there's one (1) small detail that
11 I don't think it turns on, but there is some
12 conflicting evidence as to whether the Dorsey
13 converter is included in Hydro's transmission tariff,
14 the one that they are -- use to charge people who use
15 Hydro's transmission system, third parties.
16 We know that in 2001/2002, it was cited
17 that Dorsey converted is included in the transmission
18 tariff. In other words, if you're someone in Ontario
19 trying to move power to Saskatchewan, Hydro has
20 concluded that you should pay something towards the
21 Dorsey converter because of the benefits it gives the
22 ac system. So it treated it as transmission, and
23 included it in the -- in the transmission tariff.
24 When we look at the numbers, it would
25 still appear that it's included in the transmission

1 tariff. In other places, Hydro has said that it's no
2 longer included in the transmission tariff, and we
3 haven't gotten that whole story. That's something
4 we'd -- we'd like to explore as we get closer to the
5 hearing.
6 But I don't think it's determinative
7 but it's a -- it's a good example of -- of how
8 somebody would say, well, this thing is kind of
9 neither fish nor fowl. It clearly has a -- a
10 transmission support role that at least at one (1)
11 time Hydro was willing to use to justify charging
12 third parties for -- for using the ac system.
13 BOARD MEMBER GOSSELIN: Okay. So
14 let's -- let's parse that a little bit. So the dc --
15 you know, the dc conversion was added to boost the ac,
16 is what you said. Now, why -- why would ac make any
17 difference? I mean, it -- it's -- and I can't
18 understand that. What -- why is that so significant?
19 MR. PATRICK BOWMAN: Why is it so
20 significant that the --
21 BOARD MEMBER GOSSELIN: Yeah --
22 MR. PATRICK BOWMAN: -- dc converter --
23 BOARD MEMBER GOSSELIN: -- from my --
24 MR. PATRICK BOWMAN: -- plays a role
25 in supporting the ac system?

1 BOARD MEMBER GOSSELIN: -- ac it
2 should be treated as a transmission as opposed to the
3 -- the point that Manitoba Hydro has made, which is
4 that it's just really getting power down south.
5 MR. PATRICK BOWMAN: Well, I'll go
6 through the rationale but I think it's important to
7 note that -- that whether I -- with the time available
8 that -- that was the method that was proposed by Hydro
9 and used for, you know, over a decade. So there --
10 there is some -- some thought behind it.
11 But the essence of it is if you're
12 going to look to the ac system, and what investment is
13 required to keep that ac system operating, if you
14 don't assign the dc converter, the Dorsey converter to
15 the -- the ac transmission system, you're effectively
16 given someone like the transmission tariff customers
17 or the cost of service a much -- much lower cost
18 transmission system than they would otherwise require.
19 You're effectively giving them the
20 benefit of this expensive asset, which plays a huge
21 role in supporting the ac system and -- and
22 "supporting" I don't just mean delivering power. I
23 mean in terms of power quality.
24 It plays a huge role in supporting the
25 ac system that -- that if it weren't there major other

1 equipment would need to be invested, and you're
2 practically -- you're not assigning any of that cost
3 to the users of the transmission system. And -- and I
4 -- I can try to do that somewhat more elegantly if --
5 with -- with a bit more time if we did but...
6
7 (BRIEF PAUSE)
8
9 MR. PATRICK BOWMAN: On the last two
10 (2) points, number 5 is one (1) that -- that Hydro has
11 -- Hydro has proposed that -- in terms of exports
12 there be something that they call two (2) export
13 classes. Dependable exports should be assigned a
14 share of all of the assets, include -- all of the
15 asset costs including fixed costs. Opportunity
16 exports, those that they can't guarantee they can
17 supply in a drought year, should only be assigned a
18 very low variable cost level.
19 This is the fourth time, I think, Hydro
20 has proposed that thought. Three (3) have been
21 rejected by the PUB. I think that if you get to the
22 core of -- of the argument it really comes down to
23 what are you trying to do with an export class. What
24 you're trying -- in my view, you're not using export
25 class to set rates for exports. You're not trying to

1 use it to adjust the profitability of exports.
2 You're doing it to try to ensure that
3 when Hydro builds things like Keeyask that the exports
4 make their reasonable contribution towards that asset
5 before you go trying to collect the rest of the cost
6 of that asset back from everybody else who lives here.
7 So the question is how much of the
8 export revenue should be attributed back, or -- or
9 allocated -- how -- how much should recognize the
10 investment in -- in those assets. And the -- the
11 Board has consistently recognized, and I think it's --
12 it's sensible and it's sound that you need to allocate
13 both dependable and opportunity revenues to help pay
14 for the Keeyask asset.
15 They were integral to the business
16 plan, to the decision to pursue Keeyask. If those
17 opportunity revenues had been deleted from the Keeyask
18 business case, it never would have passed the -- the
19 test. Never would have been built. We would be
20 talking about gas here, or one (1) of the other plans.
21 And so you can't now come along and say
22 I want to take these opportunities, revenues, and
23 assign them only a smidgen of cost and consider the
24 rest, you know, found money, or -- or profits that I
25 can use for something else, or assign in a different

1 way. No, you have to use them to pay for the bricks
2 and mortar, and that's the essence of -- of the -- of
3 the export 1 versus 2 class as far as -- as we've --
4 we've seen it.
5 And I -- it's particularly surprising
6 when Hydro says, well, one of the reasons for this is
7 that exports are temporary. They're not part of the -
8 - the fundamental nature of that plant going forward.
9 And even if that were a reasonable
10 rationale, it's -- the -- the part that is temporary
11 is the dependable exports. The opportunity exports
12 are here forever because the plant will always have --
13 have water that isn't used by Manitobans. We don't
14 really make use of that oppor -- or that -- that non-
15 firm, varies by year to year energy.
16 We make use of the stuff that's here
17 even during droughts. So the opportunities are the
18 permanent part of the plant. And if you look down the
19 economic scenarios, the eighty-five (85) year
20 scenarios that were run for NFAT towards the bottom of
21 the page and you look at those export revenues, those
22 are all our opportunity revenues because the
23 dependable has long since been used up by the -- the
24 domestic load.
25 So the -- the whole rationale of the

1 temporary argument, to me, if anything, goes -- cuts
2 the exact opposite way. It doesn't support assigning
3 no bricks and mortar to opportunity. If anything, it
4 supports more fully assigning bricks and mortared
5 opportunity because they're the ones that are going to
6 be here forever and justify building the bricks and
7 mortar in the first place.
8 THE FACILITATOR: Patrick, a bit more
9 cryptic to get on to the questions from others.
10 MR. PATRICK BOWMAN: Oh, yeah. Do --
11 I -- I can touch on the last one (1). The next export
12 revenue is the la -- I think everything else I've
13 already done. So the next export revenue as number 10
14 is -- this is the export revenue that's leftover after
15 being assigned a full share of costs.
16 Christensen had some -- a good way of
17 characterizing it, that this is no longer linked to
18 cost. It has no principle basis to be allocated in a
19 cost of service study. Hydro does allocate it back to
20 classes in the cost of service study sometimes as a
21 revenue, sometimes as an offset to cost. And I don't
22 see how it has any -- any reason to be included. If
23 you're going to measure the cost to the customer,
24 measure the cost to the customer, not with some offset
25 from net export revenue.

1 Over time, you might even move to
2 saying this net export revenue, if it's indeed an
3 above cost recovery from exports, could be used for
4 something else other than subsidizing the rates in any
5 given year. It could be used for -- for building up
6 reserves and -- and the like to benefit ratepayers in
7 other ways, like more stable rates.
8 And -- and that -- I -- I put some
9 quotes in the testimony that match our, mine and Mr.
10 McLaren's earlier evidence with some of the quotes
11 from Christensen's report that are almost exactly
12 parallel on that.
13 And that's the last -- the last of the
14 main recommendations. The other -- the ninth slide
15 has the five (5) that I said I wouldn't talk about.
16 And the tenth slide just had some general comments
17 about -- implicit in the testimony about how Hydro
18 runs its cost of service study in some steps that --
19 that should be considered, but that isn't where I
20 understand we need to spend our time today.
21 THE FACILITATOR: Thank you. Over to
22 Bill, I think, for questioning. And hopefully we can
23 make up a little bit of time as we move along.
24
25 CROSS-EXAMINATION BY MR. WILLIAM HARPER:

1 MR. WILLIAM HARPER: Good morning,
2 Patrick.
3 MR. PATRICK BOWMAN: Good morning.
4 MR. WILLIAM HARPER: Can we go to --
5 and, actually, when I was developing these questions I
6 -- I focused on your evidence because I didn't have
7 the be -- benefits of the last slides, but there's
8 probably a lot of overlap here. But, sort of, I'll be
9 referring more -- more to the evidence when -- when
10 we're going through this.
11 Can we go to page 12 of your evidence?
12
13 (BRIEF PAUSE)
14
15 MR. WILLIAM HARPER: And I guess in --
16 in the first sentence here you state that:
17 "The relative levels of rates
18 charged to various customer classes
19 are to be billed based on principles
20 of cost of service."
21 I think. And then -- and then if we
22 flip over to page 17, you outline what you state are
23 some appropriate and standard costs -- cost of service
24 measures, namely rever -- recovery of the revenue
25 requirement, fairness in equity, and simplicity.

1 Are these the cost of service
2 principles that you're talking about that we should be
3 following? I -- I just want -- just want to identify
4 when you make this reference on page 12 to principles
5 of cost of service, what those principles are and
6 whether they're the three (3) items you listed on page
7 17.
8 MR. PATRICK BOWMAN: No, the items on
9 17 were an attempt to categorize Hydro's list of its
10 goals into those that are appropriate for cost of
11 service and those that, in my opinion, are distracting
12 to cost of service, that they -- they should be a part
13 of other steps. And trying to embed them in the cost
14 of service really muddies up its -- its clarity and
15 its accuracy.
16 MR. WILLIAM HARPER: So it would be
17 fair to say then but -- that you would agree with the
18 fact you -- in your view, the three (3) that you have
19 outlined on page 17, recovery of revenue requirement,
20 fairness in equity and simplicity, you -- you agree
21 that those are appropriate cost of service principles?
22 MR. PATRICK BOWMAN: Yes.
23 MR. WILLIAM HARPER: And I guess are
24 there any other ones? You said you were trying to
25 parse the Manitoba Hydro principles. So, I guess, are

1 there any other principles that sort of weren't in the
2 Manitoba list that you would consider as being
3 appropriate sort of with respect to the reference you
4 make on page 12 as to principles for cost of service?
5 MR. PATRICK BOWMAN: Well, this is
6 under a section called Other Considerations. I think
7 everything about cost causation in Sections 2.2 and
8 2.3 of the evidence would be caught there.
9 MR. WILLIAM HARPER: Okay.
10 MR. PATRICK BOWMAN: And to the extent
11 fairness and equity doesn't already pick that up.
12 MR. WILLIAM HARPER: Really I guess
13 what -- to some extent, chapter 2 in your -- in your
14 evidence is really expanding on your view of how
15 fairness and equity should be interpreted.
16 Is that -- is that a fair statement?
17 MR. PATRICK BOWMAN: Well, all of it,
18 recovery of the revenue requirement, fairness and
19 equity and simplicity are all reasonable. They're
20 relatively comprehensive. It doesn't use the word
21 "cost causation" which most people would as a cost-of-
22 service principle, but they're -- you know, they're
23 fine.
24 MR. WILLIAM HARPER: I guess -- I
25 noticed on page 17, I guess, when you were parsing

1 Manitoba Hydro's list, you explicit -- explicitly
2 excluded rate stability and gradualism.
3 So I take it, in your view, they're not
4 to be considerations from a principle perspective in
5 looking at ser -- a cost-of-service methodology?
6 MR. PATRICK BOWMAN: Well, listen, if
7 -- if a cost of service study in -- in one GRA says a
8 customer costs four (4) cents to serve, and the -- the
9 next GRA you run the Cost of Service Study and you --
10 you put in all the facts and all the costs and it
11 comes out that that customer costs six (6) cents to
12 serve, you've got two (2) accurate data points.
13 How you design rates now to deal with
14 the fact that that customer went from being four (4)
15 cents to six (6) cents should deal with things like
16 stability and -- and a bunch of other consideration.
17 But you don't -- to me, you don't
18 undermine the methods of the -- of the Cost of Service
19 Study to achieve -- to achieve that. You don't hide
20 the fact that the cost is six (6), or you don't -- you
21 don't somehow monkey up the four (4) to try to get
22 closer to where you think the next one's going to be.
23 MR. WILLIAM HARPER: So, I mean, I
24 think you made some statements in your sort of
25 presentation about the fact that Manitoba Hydro uses

1 the fifty (50) highest hours in the winter and the
2 fifty (50) highest hours in the summer as opposed to
3 just the one (1) coincident peak hour.
4 And I think we heard sort of -- sort of
5 -- I won't say, "testimony," but information from
6 Manitoba Hydro when they were here in May about how
7 one (1) of the reasons for doing that was because the
8 peak tends to move around in terms of where it is and
9 what customers or classes are going to contribute to
10 it.
11 And part of their rationale for using
12 the fifty (50) hours was to try and introduce some
13 stability into the cost-of-service methodology. And
14 in your view, that's -- using fifty (50) isn't -- is
15 inappropriate in your view? We should be using the
16 most recent number for the most recent year we've got
17 available every time and running our Cost of Service
18 Study just on that?
19 MR. PATRICK BOWMAN: No, because I --
20 I disagree with that because your Cost of Service
21 Study is prospective. And on a prospective basis, we
22 don't assume that we're going to be able to forecast
23 every hour of the year at every customer's load in
24 every hour of the year precisely.
25 If you don't use the fifty (50) hours,

1 what you end up with is something like a one (1) hour
2 peak where you would say, If that peak hour happens to
3 be at -- at dinnertime on a holiday, your -- your
4 small business would use -- are using almost no peak,
5 whereas if it happened to be on a Thursday at 4:00
6 p.m., small businesses may be using a lot of peak.
7 And we don't know in advance which one
8 it's going to be. So our -- our best estimate of the
9 contribution is -- is an average of -- of those
10 things. It's -- so it's not -- it's not meant to just
11 achieve stability. It's meant to represent our -- our
12 best attempt to do a forecast of what's appropriate in
13 that year.
14 MR. WILLIAM HARPER: Okay. Thanks.
15 The other thing I was trying to understand, and I
16 think you just referenced it a bit in your -- in your
17 comments, is that, you know, if you do one (1) cost of
18 service study and it says a class's average cents per
19 kilowatt hour would be four (4) cents, and you do one
20 the next year and it comes out at six (6) cents, you -
21 - you can address that through rate design I think was
22 the comment you -- you made, or you should be able to
23 address that through rate design.
24 And I guess -- I guess I'm struggling a
25 little bit. When you say, "rate -- rate design," does

1 -- does that include the fact that you may actually
2 design the rates so that they don't actually recover
3 the six (6) cents that the Cost of Service Study says
4 -- says is the appropriate cost at that point in time?
5 Or is there some way you can design the
6 rates so that, even though the average rate's going up
7 by 50 percent, people -- customers aren't going to
8 have any rate shock?
9 MR. PATRICK BOWMAN: Well, I guess it
10 depends on what's happening to our revenue requirement
11 because you first have to solve that problem. I've
12 dealt with situations where utilities have 50 percent
13 jumps in their -- in their average rates because of,
14 you know, the buying in Yukon closes, or fuel prices
15 double in the Northwest Territories or something. And
16 -- and then you don't have a choice. You have to
17 impose those -- those rate shocks.
18 But I only know of one (1) example of
19 any utility who aims to have a revenue-cost coverage
20 ratio of 100.00 percent every time they run the Cost
21 of Service Study, which would be the equivalent of
22 saying, in that first example, I charge four (4)
23 cents, in my second, I charge six (6) cents, and --
24 and, dammit, that's the rate.
25 The -- the norm is that you say, No,

1 no, I run the four (4) cent one. The next time, I run
2 six (6) cents. If someone else has gone down or I
3 don't need a big rate increase, it's just some
4 shifting between the classes, then that -- that one
5 (1) customer class will show an RCC ratio that will be
6 well below a hundred (100).
7 And so they should receive above-
8 average rate increase, but it doesn't mean necessarily
9 sharp shock to them to get them all the way up to
10 ninety-five (95) or to a hundred in one (1) fell
11 swoop. You -- you have -- have time to deal with that
12 within -- within rate design and -- and the Bonbright
13 principles which include graduals.
14 MR. WILLIAM HARPER: That will be
15 fine. No, thanks. I think that -- that helps. Can -
16 - can we go to page 20 of your evidence?
17
18 (BRIEF PAUSE)
19
20 MR. WILLIAM HARPER: In here you're
21 discussing the weighted energy allocation. I think
22 you alluded to that somewhat in your -- in your
23 presentation. You -- would I -- would I be correct in
24 saying, if I read this section here, that you're
25 correct -- your concern is that the -- I won't use an

1 acronym, the surplus energy program prices used in the
2 weighted don't include any recognition of the cost of
3 capacity, and only pick up variations in timing the
4 cost of energy.
5 Is -- is that your fundamental concern
6 with -- with what Manitoba Hydro is using in their
7 weighted energy?
8 MR. PATRICK BOWMAN: I think it -- I
9 think it's broader than that. The surplus energy
10 prices are a mix of complex factors in the export
11 market, as -- as well as -- as some concerns at the
12 border and the like. So in the first instance, we
13 have to be careful about taking a cost of service
14 study and making it too much about reflecting what
15 export prices are.
16 The -- the point of this is not to
17 price exports or to let export markets drive our --
18 our system costs. Our system costs are what they are.
19 Our loads are what they are. The point of this is
20 just to introduce in some -- in some directional way
21 the idea that energy in some periods matters more than
22 energy in other periods.
23 SEP prices are directionally
24 appropriate. They're -- they're suitable for that
25 purpose when you're weighting energy. But in terms of

capacity, first, no, I -- I don't see that SEP prices would necessarily include a capacity component in any material way.

Second is even if they did, I'm not sure that an export capacity price signal is what you're really trying to get at. You're trying to get at like cost of capacity that has been linked to Hydro's investment, not what -- what a gas turbine in Minnesota is -- is building for right now.

And -- and third, even if you were able to -- to try -- or were -- were trying to infer export capacity prices, you wouldn't do them across an average of six hundred (600) winter peak hours, and -- and six hundred (600) summer peak hours. You would do them on a much, much finer level than that.

But -- so for all those reasons this -- this does a terrible job of trying to -- to pick up the concept of -- of capacity cost drives and capacity investment in Hydro's generation system.

MR. WILLIAM HARPER: I mean -- I mean, we could -- we could refine the -- I mean, even at the time that it -- the weighting factor -- weighted energy factor was introduced there was a discussion about how many time periods we -- we use and, you know, there was originally four (4). Then it went to

1 twelve (12). There was some discussion about whether
2 it should be great -- greater than that.
3 And I think Manitoba Hydro indicated
4 that they didn't feel there was much there -- much
5 more to gain from that, I guess. Would you agree one
6 could explore -- try to introduce a more finely --
7 finely differentiate the -- the time -- the time
8 periods if you're doing a weighted energy allocation?
9 MR. PATRICK BOWMAN: You could. I
10 even heard rumour that Bonneville Power does it for
11 eight thousand seven hundred and sixty (8,760)
12 periods. I don't recommend that. I see some wide
13 eyes behind you.
14 MR. WILLIAM HARPER: Wide eyes, or
15 white eyes?
16 MR. PATRICK BOWMAN: Yeah. But even
17 then it wouldn't resolve the other issues I have
18 mentioned, which is you're trying to capture capacity
19 linked to -- you know, capacity costs -- go ahead and,
20 you know, review the NARUC manual, capacity costs are
21 about bricks and mortar. They're about fixed
22 investment.
23 What -- what the export market happens
24 to be pricing capacity at is not necessarily your --
25 your key consideration when you're trying to run a

1 cost of service study. And -- and even if it were, it
2 -- you know, it -- it may not be embedded in --
3 sufficiently embedded in th SEP prices given that
4 they're linked to a short-term type of market.
5 MR. WILLIAM HARPER: I guess the final
6 question I had on this particular topic was that I
7 think we -- we've had some discussion about the fact
8 that -- that there probably is some -- you've
9 acknowledged there probably is some capacity
10 considerations in the actual SEP prices as -- as we
11 see them.
12 And so I guess the question is with
13 respect to your proposal, which would be to use
14 something like the peak credit method and then
15 allocate the energy portion of the cost to customers
16 in -- you know, using -- using Manitoba Hydro's
17 weighted energy without the capacity adder, it seems
18 to me we still have some capacity considerations in --
19 in that weighting that -- that you've acknowledged,
20 and therefore we're going to double counting in some
21 extent as to capacity costs and the overall approach.
22 And wouldn't we have to ensure if we're
23 using your approach that the energy weightings we're
24 using are reflected just of variations and energy
25 costs and don't include any capacity considerations in

1 -- in them when we apply them?

2 MR. PATRICK BOWMAN: No, and there's

3 three (3) reasons for that. One (1) is I don't

4 necessarily acknowledge that twelve (12) period

5 marginal cost weighted energy has any significant

6 capacity signal in it whatsoever.

7 Even if the SEP underlying prices did,

8 by the time you average them across six hundred (600)

9 hours they don't -- they no longer have that. And the

10 -- the second reason is as -- as I go through in the

11 testimony, even if you look at something like a wind

12 resource, which has no capacity, so Hydro assigns it

13 zero capacity value in its entire system.

14 If I go to Manitoba Hydro and say I've

15 got a -- a wind turbine, I'll -- I'll -- I'd like to

16 sell you the power and they go to do an economic

17 evaluation, if my wind turbine is in a place where it

18 only blows on -- on warm spring evenings, I'm going to

19 get a very different price offer from Manitoba Hydro

20 than if I have one (1) that blows at -- across the

21 cold days of winter, even across many cold days of

22 winter.

23 And that's because energy is worth

24 different amounts in different periods regardless as

25 to whether it's -- it's considered firm capacity or --

1 or a contribution to those very high peak hours. And
2 that's -- that's why I think it's appropriate to use
3 the weighting for -- for the -- a wind, to use a
4 weight energy.
5 MR. WILLIAM HARPER: Okay. Thanks.
6 Can we turn. Can we have page 23 of your evidence?
7 And this is where you're talking about the equivalent
8 peaker method and the 23 -- and the 23 percent of that
9 coming out as to -- to demand related costs?
10 MR. PATRICK BOWMAN: Yes.
11 MR. WILLIAM HARPER: I guess -- if I
12 understand -- if I recall correctly, this was the
13 estimate that was provided during the 2014 workshop
14 and was based on the cost of the peaker plant relative
15 to the cost of -- of Wuskwatim, if I'm not mistaken?
16 MR. PATRICK BOWMAN: That's correct.
17 MR. WILLIAM HARPER: Okay. And,
18 however, you know, I -- you don't -- you -- you can
19 turn it up if you want to or not. If -- if we were to
20 look at Appendix 4 -- page 8 of Appendix 4 of Manitoba
21 Hydro's filing, we -- we see there that Manitoba Hydro
22 -- in that appendix you used a somewhat different
23 approach.
24 And the estimate of demand related cost
25 they came up with was 15 percent as opposed 23

1 percent. Are -- are you familiar with -- with that
2 evidence?
3 MR. PATRICK BOWMAN: I recall reading
4 that and I recall reading some estimates developed by
5 Mr. Chernick and I -- I'm trying to remember which
6 method -- which one (1) uses which method. But my
7 concern with one (1) of them, if not both of them, was
8 that they were focusing only on the installed cost of
9 the capacity, not the levelized cost.
10 Which of course if you're talking about
11 a hydro plant is a much longer life and so you -- as -
12 - as well as costs are built into the -- the levelized
13 amount. So the -- the -- to me, the -- of the -- of
14 the examples available, the Wuskwatim one (1) was --
15 was probably the -- the most reasonable in evidence
16 available to use without someone trying to create a
17 method on the fly.
18 MR. WILLIAM HARPER: And I guess, but
19 even -- I mean, we go back to your earlier comments
20 about how you're trying to look at the cost of what's
21 on -- you know, what -- what Hydro's built and what's
22 on the system, the bricks and mortar.
23 And if I'm talking about a method
24 that's comparing a peaker plant to Wuskwatim, that's
25 just one (1) of the plants that Manitoba Hydro's got

1 on its books and actually it's the most recent plant.
2 And so I guess to some ext -- and we
3 all know that what happened to the costs of Wuskwatim
4 to be quite honest with you. So I guess the question
5 is, I'm struggling with, you know, why that would be
6 the best approach?
7 And maybe at this point in time maybe
8 our best point of agreement is, can we agree there are
9 a number of ways the peaker credit method -- or the
10 equivalent peaker method can be applied? There's a
11 number of different approaches to applying it. And
12 there's probably debates over which approach is the
13 best one (1).
14 MR. PATRICK BOWMAN: Sure, I accept
15 that. And -- and I think if -- if somebody came back
16 with the concept that you'd use -- use 15 percent
17 today and stick with the recommendation I have there
18 that Hydro should go look at the alternatives and --
19 and come back with a proposal where they've done the
20 work to -- to see which method is best.
21 I haven't said 21 -- 23 percent is a
22 fixed number or that it should be based on that
23 methodology forever. Just at this time if you're
24 trying to do something that reasonably represents the
25 cost of the system, a -- a capacity value in that

1 range would be not surprising to me and -- and fairly
2 consistent with what's -- what's in the evidence.
3 MR. WILLIAM HARPER: Okay. And I
4 think -- would you say it's consistent with the
5 evidence of what we've seen from Manitoba Hydro, is
6 that if you were to use something like 15 percent the
7 resulting revenue to cost coverage ratios you'd get
8 applying that method in 15 percent probably wouldn't
9 be that much different than -- than the method they're
10 using right now?
11 MR. PATRICK BOWMAN: No, because when
12 Hydro's run the fifteens (15s) and the twenties (20s)
13 and the thirties (30s) it -- it always takes the
14 energy side and turns it to unweighted energy. And as
15 I've already said, the -- the weighted energy part is
16 fine.
17 The weighted energy part is exactly how
18 you should treat the energy, because energy has a -- a
19 varying value in different periods. Capacity is
20 something different. And so as long as you come up
21 with a ratio here that's -- that's reasonable for
22 today for the purposes of estimating some -- some
23 PCOSS results, do some more homework on inflation
24 adjusting the old plants to come up with a value as --
25 as a lot of people who use this method do.

1 Or -- or if Hydro wanted to come up
2 with a different method, then I think people could
3 usefully debate that. But that's not a reason to
4 abandon the idea that -- that energy is worth
5 different amounts in different periods.
6 MR. WILLIAM HARPER: Okay. We can say
7 different amounts in different periods without any
8 capacity considerations.
9 Would you agree to that qualifier?
10 MR. PATRICK BOWMAN: Even without
11 capacity considerations, energy is worth different
12 amounts in different periods.
13 MR. WILLIAM HARPER: And I guess the
14 weighted allocator. But would you then agree the
15 weighted allocated we -- we would use would have to be
16 one that did not include any capacity considerations?
17 MR. PATRICK BOWMAN: Yeah. I think
18 the -- the -- Hydro's attempt to take the old, long-
19 standing, twelve (12) period weighted method and
20 introducing to it the curtailable service credit,
21 which only shows up in PCOSS14, is -- is not doing
22 what was intended.
23 And I -- I don't think it -- I don't
24 think it achieves the end result, and I wouldn't -- I
25 wouldn't recommend using it considering the

1 alternative of -- of explicit recog -- recognizing
2 capacity.
3 MR. WILLIAM HARPER: I was curious
4 because your -- you -- you recommend using this PCOSS
5 credit method, but they recommended taking wind and
6 pulling it out and treating all as energy.
7 So if we were to use the 15 percent
8 example, once you pulled wind out and treated it all
9 as energy, we'd end up with an overall demand energy
10 split where the demand portion was something less than
11 15 percent again, would it not be, if you look at the
12 treatment of generation overall?
13 MR. PATRICK BOWMAN: Right. And I did
14 have a comment in the presentation I glossed over on
15 this, but one (1) of the unique aspects of Hydro's
16 system is that we rarely go through and look at plant
17 by plant what function do they play. We sort of talk
18 about this conglomerate of -- of generating assets.
19 Occasionally something like wind will
20 get talked about different, and -- and by wind, we
21 actually mean purchase power. But occasionally wind
22 will -- will get talked about differently.
23 Occasionally a coal might be talked about differently.
24 But otherwise, we kind of say, Well, all these plants
25 do the same thing.

1 In -- in, you know, a norm of cost of
2 service experiences I've been through is one would
3 actually look at -- pierce that veil and get into
4 plant by plant and say, No, no, Grande Rapids actually
5 plays a very different role in the system than -- than
6 Kettle does. And so let's look at -- at how to treat
7 all of those.
8 But as I was discussing with the -- the
9 chairman earlier, one (1) of the natures of Hydro's
10 system is that that role is not only different for
11 every plant, it's different for every waterflow for
12 every plant.
13 And by the time all is said and done,
14 if ever there were a utility that you could take
15 almost all of the plant and say, That functions as one
16 (1) block, and I'm not going to try to pierce that
17 veil and figure out what everything's doing, it's
18 probably Manitoba Hydro because droughts look
19 different than floods look different than average with
20 different -- you know.
21 MR. WILLIAM HARPER: The analogy I had
22 a boss use to me a long time ago is if I have a -- I
23 have a sweater. And it looks very nice except for
24 this one (1) little piece that's sticking out. And as
25 I try to pull out that one (1) little piece, all of a

1 sudden the sweater starts -- you know, by the time I'm
2 finished, my sweater looks a lot worse than it was as
3 I try -- as I -- as I try to fix it.
4 And so I think this is sort of the
5 analogy. And sometimes if you try to unravel things,
6 sometimes they're worse than they were -- you end up
7 with something that's worse than you started with sort
8 of thing.
9 MR. PATRICK BOWMAN: Well, and -- and
10 just to emphasize that, it hasn't been talked about
11 here a lot, but Hydro's PCOSS14 over -- overhauls,
12 throws out a lot of previous PUB recommended methods.
13 And some of them are -- are very substantial changes,
14 but they tended to get into the unravelling of the
15 sweater.
16 And -- and we supported on almost all
17 of those even though, if you want to look through the
18 RCCs, they go significantly against the industrial
19 class. But previously, the -- you know, at one point,
20 wind and power purchases were assigned directly to
21 exports because we never would have built the wind
22 without exports.
23 And -- and DSM was assigned directly to
24 exports and coal was assigned 50 percent to exports
25 here but 100 percent there, and natural gas and -- and

1 all these pieces carved up and assigned out. And --
2 and if you sit and look at that, you worry that you've
3 got a pile of -- of wool rather than something that
4 works as a whole.
5 And so, you know, in -- in terms of
6 Hydro's -- I -- I have the list. Hydro ran MIPUG MFR-
7 5 where they listed eight (8) things that the PUB had
8 previously directed them in one direction, and they
9 were proposing to go in another direction here.
10 At least six (6) of those we agree
11 with. One (1) we stick with the PUB on, which is the
12 two (2) -- or the one (1) export class versus two (2),
13 and one (1) of them I'm not really sure. It's a very
14 -- it's a very small item, but it's something about
15 actual exports or imports, and it's --
16 MR. WILLIAM HARPER: I'd like to
17 finish my conversation about the sweater, about
18 talking about Brandon, your recommendation on that.
19 And I think you recommended that -- which is part of -
20 - you know, it's probably an example from rambling in
21 terms of taking Brandon out and allocating it just to
22 the domestic class I think was -- was your
23 recommendation.
24 And I guess the question I was
25 struggling with there was: If I take Brandon out and

1 allocate it just to the domestic class, and recognize
2 that Brandon is providing energy and capacity just to
3 the domestic class, does that mean I have to somehow
4 adjust the allocators I'm using for everything else?
5 The "everything else" is what I'm
6 allocating between exports and domestic. But since
7 I've already assigned some -- domestic some -- some --
8 you know, some energy costs and capacity costs through
9 -- through the out -- through the assignment of
10 Brandon, do I have to somehow adjust my allocation for
11 the balance of the cost and -- and if so, what I've
12 been struggling with, how the heck would I do that, to
13 be quite honest wi -- with you, Patrick?
14 And I guess I was wondering with
15 whether you accept the point in principle that this is
16 part of the sweater that, if I take Brandon out, I
17 have -- mainly have to do something different with --
18 with the balance of the generation costs when I look
19 at the allocation between domestic and exports?
20 MR. PATRICK BOWMAN: I think there may
21 be merit in your comment. To stick with the sweater
22 analogy, I'm not sure Brandon's a string as much as a
23 -- as a pill one could take off of the -- the sweater
24 because it so uniquely identified in terms of its
25 role, in terms of the legislation, in terms of the

1 situations, would it be used if ever.
2 I -- I think there's -- if -- if ever
3 there were ability to carve one (1) out, that would be
4 it. Would that then mean that domestics have --
5 domestic customers have sort of claimed some energy.
6 Now that you've been assigned the cost of Brandon
7 you've claimed some energy, so your pool energy is now
8 down a bit and we got to do -- and -- and as a result,
9 the exports may get a little bit bigger percentage of
10 what remains.
11 I -- I suspect you'd be into eight (8)
12 decimal points of rounding -- or of -- if -- if you
13 were trying to make that change, I -- I think the cha
14 -- I think it would be absolutely insignificant.
15 Now, if somebody comes along and says,
16 no, no, I want to do that with -- with the -- the
17 purchased power, like, the wind, or I want to do that
18 with Wuskwatim, that -- that -- yeah, that -- that is
19 -- that is a string in the sweater.
20 MR. WILLIAM HARPER: No, thanks. I
21 think that's -- and I'll leave... Like, I -- I -- you
22 know, I guess I had a question here about -- and I was
23 curious about your -- the final thing I was curious in
24 this area was you're talking about allocating the
25 generation costs basically to domestic plus all of

1 exports, the fixed cost, the both -- both opportunity
2 exports and -- and dependable exports.
3 And I was curious within that paradigm
4 why you would still be recommending using 1 CP just
5 winter -- just winter peak loads even though you're
6 trying to appor -- you know, the view of this is to
7 try to apportion costs between the exports and the
8 domestic load. And when you -- and, you know, as
9 we've seen in the tables, once you include all exports
10 in those loads the summer doesn't look that much
11 different tha -- than the winter.
12 MR. PATRICK BOWMAN: And -- and that's
13 why for 80 or 85 percent of the costs I say you can do
14 them on marginal cost energy, which would weight the
15 summer a lot like the winter. It's only that small
16 amount that I would say would go to peak that you
17 would look at -- at the peak driver. And the main
18 reason for using -- I say, 1 CP, but remember it's
19 more like 3 CP. The main reason you use that is that
20 the -- the fundamental planning tables that Hydro runs
21 and -- and the -- the drivers for assessing capacity
22 investment focus on winter peak, they don't -- they
23 don't focus on the summer peak. And they're --
24 they're in the power resource plan they produce every
25 year.

1 MR. WILLIAM HARPER: Okay. You -- you
2 talked a little bit about the role of export revenues
3 in sort of the NFAT process and the sort of decision
4 to advance Keeyask. And I don't -- and I --
5 personally, I -- I don't -- I don't have any issue
6 with -- with your -- with your claim that both
7 dependable experts and -- and opportunity experts
8 contribute to the overall economics that -- that sort
9 of lead the decision that it was going to be
10 beneficial advance Keeyask.
11 What -- what I was struggling with is,
12 do you recall that in the NFAT there was some
13 uncertainty about the WPS contract and whether or not
14 Manitoba Hydro is actually going -- you know, during
15 the hearing there -- some uncertainty developed as to
16 whether that contract was actually going to come --
17 come about or not and whether they -- they could rely
18 on that contract for purposes of -- of doing their
19 economic evaluation or do -- or can -- can you
20 remember back that far at this point in time?
21 MR. PATRICK BOWMAN: Other than the
22 PTSD, Mr. Harper, yes, I recall that.
23 MR. WILLIAM HARPER: And I guess would
24 you also recall there were cases run with the
25 preferred plan with and without the WPS contract and

1 when you took out the WPS contract and sort of, you
2 know, didn't treat them as dependable sales, the --
3 sort of basically the net present value of -- of the
4 preferred plan went down?
5 MR. PATRICK BOWMAN: I can't recall
6 that scenarios that were run without the WPS contract
7 would have taken that same energy and considered it
8 opportunity. I -- I seem to recall testimony that
9 when the WPS contract wasn't in, that was instead
10 turned into some other notional dependable contract.
11 I could be wrong.
12 But either way, the economics went
13 down. I'm not sure whether it was necessarily saying
14 all this great dependable energy will just dump at
15 opportunity or whether it's saying, no, no, we'll turn
16 -- turn to someone else who's not quite as good as
17 Wisconsin but who -- who's still going to give us a
18 dependable sale.
19 MR. WILLIAM HARPER: Well, maybe on a
20 more generic level, would it be fair to say that sort
21 of dependable exports -- if -- if we're doing such an
22 evaluation, looking at sort of the economics of
23 advancing a -- a generating station, dependable export
24 sale on a per kilowatt hour basis has -- sort of give
25 us more leverage for that business case in the sense

1 of 1) They're much more assured. We're probably
2 getting a higher price for them than -- than we are
3 for -- for all over opportunity exports on a kilowatt
4 hour basis?
5 They -- you know, they probably
6 strengthen the -- the economic case more -- more than
7 opportunity exports are. Can -- would you agree with
8 me on that?
9 MR. PATRICK BOWMAN: Well, you run
10 into competing factors, there. So on the one (1)
11 hand, I would agree that dependable exports underpin
12 the development more than opportunity in the near term
13 because they tend to have a greater value, but they're
14 also more temporary.
15 So if you look at the -- the long-term
16 scenario, opportunity exports will be there forever
17 because they produce a type of -- of surplus energy we
18 don't use and will always take to market, whereas
19 dependable will -- will disappear as domestic load
20 grows. And, of course, you have a -- a discounting
21 factor that the further out you get, the less it's
22 worth, and so there's these two (2) competing things.
23 It -- probably there's way more
24 opportunity to export kilowatt hours in the mix. Is
25 it worth more to the -- to the economic scenario? I -

1 - it -- it may be, but I -- I think it might be a
2 wash.
3 MR. WILLIAM HARPER: Well, I guess the
4 -- my problem with that response is, is if we're just
5 looking at advancing a station as we talked with
6 Keeyask, it really -- it was an -- it was an
7 advancement station with Wuskwatim's advancement
8 station.
9 Those opportunity sales are going to be
10 there whether we advance or not, because once this --
11 under even the alternative option, which was just
12 build it when we need it, the station will be there
13 and the opportunity sales will be -- take -- will be
14 taking place over -- over the long term.
15 So in both -- both scenarios, when I --
16 when I get out ten (10) -- ten (10) years, I probably
17 got the same level of opportunity sales in both cases,
18 because the plant's in place and, from an economic
19 benefit perspective, there is no difference between
20 the two (2).
21 So I guess I -- I'm struggling with
22 this view that opportunity exports contributed a lot
23 more to the types of business cases we've been looking
24 at than dependable exports. When -- when I be -- get
25 out beyond the advancement period that I'm talking

1 about, it's the same level of opportunity exports in
2 both cases.
3 MR. PATRICK BOWMAN: So the -- there's
4 no doubt that dependable sales are integral to the
5 decision to advance. I accept that. But opportunity
6 sales are integral to the decision in the first
7 instance to have a Keeyask at all. But for
8 opportunity sales, we wouldn't even be talking about
9 hydro plants. We'd be talking about the gas or
10 thermal plants down south.
11 It's only because you can take -- you
12 know, Keeyask numbers -- I just was looking for it --
13 Keeyask has about 3,000 gigawatt hours of dependable
14 energy, and another 1,400 gigawatt hours of -- of
15 opportunity energy that's always going to be there.
16 It's -- on average. In -- in flood years, it'll be
17 higher, in drought years it may be -- in -- in theory,
18 it might go down to zero in one (1) -- one (1) year
19 out of a hundred.
20 But on average, that fourteen hundred
21 (1,400), that's -- that's a third of the -- of the
22 energy output through -- through its entire life. If
23 -- if you couldn't get that value for that opportunity
24 somewhere, you -- you never would get over the hurdle
25 of having those type of plants.

1 And that's why if you look at anywhere
2 that is not interconnected, like -- like Newfoundland,
3 I'm -- I'm told, their supply mix on the island is
4 designed to be about -- I don't know, a mix of hydro
5 maybe 60 percent, maybe -- maybe they get up to sixty-
6 five (65), and the remaining is thermal, because you -
7 - you just can't justify adding -- adding more hydro
8 plants at that point, where we're -- we're trying to
9 get to ninety-nine (99), right.
10 MR. WILLIAM HARPER: I -- I know.
11 It's Bill. I'm -- I'm a little bit over my time, and
12 I -- I'm not sure even when I started, sort of thing,
13 so...
14
15 (BRIEF PAUSE)
16
17 THE FACILITATOR: Thanks, Ron. I
18 marked it down, Bill. How about if we go till 10:35
19 for you?
20 MR. WILLIAM HARPER: Okay. No, I just
21 wanted to make sure I -- I wasn't sort of the -- take
22 -- taking up more than my allotment of the time.
23 Can we -- can we go to page 42 of your
24 evidence?
25

1 (BRIEF PAUSE)

2

3 MR. WILLIAM HARPER: Okay. Here --

4 here you identify -- here you talk about the fact

5 there are a number of benefits to customers

6 participating in energy efficiency programs received

7 over and above the -- the lower bills that we

8 typically think about. And that, you know, these are

9 all other good -- other good benefits that customers

10 get when -- when they participate in -- in DSM

11 programs.

12 MR. PATRICK BOWMAN: Yes.

13 MR. WILLIAM HARPER: I guess -- I

14 guess -- I mean, have -- having said -- said that,

15 would you agree that Manitoba Hydro's DSM programs

16 focus on -- on encouraging customers, and sometimes

17 stakeholders who -- who aren't customers, maybe

18 landlords, people like that, to undertake efficiency

19 initiatives that left -- left to their own devices or

20 decision making they wouldn't otherwise unde --

21 undertake?

22 MR. PATRICK BOWMAN: I think that's

23 the objective. I -- I don't know how much effort has

24 been put into -- in -- in -- necessarily proving

25 that's the case and -- and doing a -- a significant

1 measurement of -- of free riders. It's not -- it's
2 not an area that I spend a whole lot of time assessing
3 Manitoba Hydro's experience with.
4 But -- but, no, I -- I accept that
5 that's -- that's the intent of what they're trying to
6 do.
7 MR. WILLIAM HARPER: And so that
8 despite all these other purported benefits that might
9 be coming to it, they -- you know, customers aren't
10 undertaking these initiatives unless, to a large
11 extent, you know, we can argue about free riders and
12 to the extent they're taking account into program
13 design, but -- in the level of incentives, and the
14 economics, but in general, the view is is that
15 customers won't be participating in these programs
16 unless Manitoba Hydro encourages it to do so and
17 typically does so through some financial incentive?
18 MR. PATRICK BOWMAN: Yeah, I think
19 that's the design. Financial incentive is -- we have
20 to be careful about, because there is one (1) of the
21 biggest DSM areas is Codes and Standards, which isn't
22 necessarily a financial incentive, it's -- it's Hydro
23 paying for their staff to fly off to national meetings
24 where they impose new dishwasher energy efficiency
25 standards, which Hydro claims is a -- a DSM benefit,

1 right, because now everyone has to buy a more
2 efficient dishwasher.
3 MR. WILLIAM HARPER: Yes.
4 MR. PATRICK BOWMAN: But -- so it's
5 not always financial.
6 MR. WILLIAM HARPER: Then page -- line
7 16, and this was the one that was particularly curious
8 to me. At line 16, you say:
9 "Under Hydro's approach, if a
10 program is run to benefit a
11 particular class, but is not
12 economic -- economic as a source of
13 adding grid supply, the other
14 classes need not pursue as
15 aggressively the weaker economics of
16 this program."
17 Is -- is it your assertion that
18 Manitoba Hydro actually sort of offers such programs
19 that aren't economic from -- from a system benefit
20 perspective, that are there basically just -- you
21 know, the economics of it is just based on the
22 participating class and the participating customers?
23 Which -- which is what you seem to be suggesting here.
24 MR. PATRICK BOWMAN: Well, listen,
25 there's a -- we -- we went through an exhibit at NFAT

1 that -- that explained DSM economics. And the essence
2 of it is I -- I sat through a meeting not that long
3 ago with -- with some executives at Hydro who were
4 explaining that one (1) of the important parts about
5 doing -- doing DSM right now is that -- is that we're
6 -- we're already into 2016, and if we don't get DSM
7 going, we might be forced to build Conawapa in the
8 late 2030s, where otherwise, we could have deferred
9 that if only we had our DSM ramped up, which got a lot
10 of puzzled looks about how much is this DSM achieving
11 that we're doing today to lower your load in 2030?
12 And -- and they were sort of calculating back.
13 Well, if it -- if it's needed for the
14 late 2030s, you'd have to make your -- your commitment
15 to it in sort of the -- the early 2030s, maybe late
16 2020s you'd be planning. And -- and that only gives
17 us, you know, twelve (12) or thirteen (13) years to
18 prove our DSM is really working before we can even
19 start to effect that -- that planning cycle, which got
20 a -- a few more puzzled looks.
21 I think the essence of it is if -- if
22 you want to spend a bunch of money on DSM right now,
23 you need to figure out what it's doing to rates today
24 and what it's doing to rates over the long term --
25 over the long term. The essence of what Hydro's DSM

is -- is moving towards and is being discussed as is the fact that it can defer the need for Conawapa from the late 2030s to some later date.

Over the short-term, what it's doing is freeing up energy that can go to export markets at a very low price. And so if you're going to spend some money on DSM, looking at the kilowatt hours, you've actually achieved, not the free rider kilowatt hours, looking at the lost revenue that arises from doing that DSM, which it does -- does go into the overall mix of rate increases Hydro is seeking, and compare that to the gained revenue on an export market in the near term and probably for the next decade or two (2), DSM programs are -- are raising people's rates.

That's -- and there's no surprise. If you look -- read Hydro's GRA, it'll say one (1) of the reasons we need rate increases is because we're do so much DSM. So it's the backdrop of that. You say, Well, maybe we shouldn't be doing so much DSM. And -- and customers can be raised by -- questions can be raised by customers about whether this is -- Hydro is overdoing on DSM.

One (1) thing that will calm a lot of those questions is to say, Don't worry, because the classes that are participating and getting the

1 benefits are being assigned the costs. So you don't
2 have to get revved up because we're in Costco handing
3 out LED lightbulb coupons to people, where those LED
4 lightbulbs will be long since disposed of before
5 Conawapa ever gets here, because you'll -- those won't
6 be allocated to you.
7 Those will be allocated to that class
8 and that class can go ahead and assess whether they
9 want that or not, but probably they will, because
10 their -- their overall -- of -- have a balance of --
11 of some benefits like improved lighting quality and
12 changing a lightbulb less often, and -- and less
13 waste, and all the things that go along with it.
14 So I think that -- that's the essence
15 of it is -- and it's a very challenging framework for
16 doing DSM where Hydro's in right now when the horizons
17 are so long and the -- the export markets are --
18 especially the opportunity ones are so low, that you
19 don't want to set up a system where every customer
20 class is feeling significantly skeptical and adverse
21 to Hydro's DSM efforts because Hydro's over-
22 participating in the other class.
23 And -- and that can go both ways. That
24 can go industrials versus -- versus residentials or
25 residentials versus industrials.

1 So having said all of that, I'm -- I --
2 I don't think this makes much of a difference in the
3 dollars at the end of the day anyway, because the --
4 the DSM costs allocated via generation versus the CSM
5 class directly assigned will still tend to reflect the
6 size of the class and the amount of DSM they get.
7 But that's -- that's the rationale that
8 I was trying to set out in that sentence.
9 MR. WILLIAM HARPER: Well, I think at
10 this point, I'll -- I'll conclude and will help us get
11 back on our schedule again.
12 THE FACILITATOR: Thank you very much,
13 Bill. Let's take a fifteen (15) minute break until
14 quarter to 11:00.
15
16 --- Upon recessing at 10:30 a.m.
17 --- Upon resuming at 10:47 a.m.
18
19 THE FACILITATOR: So over to Green
20 Action for questions. Thank you.
21
22 (BRIEF PAUSE)
23
24 CROSS-EXAMINATION BY MR. PAUL CHERNICK:
25 MR. PAUL CHERNICK: Sorry, we have a

1 tangling of cords here, transmission-distribution
2 issue. Okay. Is that a little better on the sound?
3 I -- I'm going to be skipping around a
4 little bit trying to fill in holes left behind by My
5 Friend from the Coalition and dealing with some things
6 that came up in the -- in the back and forth. So my
7 apologies if -- if this isn't as smooth as it might
8 have been.
9 But first, I want to start with your
10 idea of economic identity. And -- and first, I'd like
11 to get clear, is that something that you -- that --
12 that you came up with, or is that a standard term from
13 some other branch of economics that you've adopted
14 here?
15 MR. PATRICK BOWMAN: It's not a
16 standard term at all. It was just an attempt to -- to
17 take cost causation to a more refined first-principles
18 level because of the specifics of Manitoba Hydro that
19 I referenced.
20 MR. PAUL CHERNICK: Okay. Now, could
21 you just help clarify for me what the idea of economic
22 identity adds to the idea of cost causation?
23 MR. PATRICK BOWMAN: Well, you could
24 go through Section 2. The idea is simply to say that
25 if you listened to the last workshop, if you hear

1 different people involved in Manitoba Hydro's
2 operations versus planning, if you go to different
3 utilities, the -- "cost causation" is a term that is
4 used broadly, but not always consistently deeply.
5 To an operator, one (1) thing causes a
6 cost. To a planner, other things cause costs. To a -
7 - a historian, other things cause costs. And all of
8 them sound tempting and appealing, but only some of
9 them are right.
10 And so it was a way to try to take --
11 just -- just take -- peel -- peel back a bit of the --
12 of the -- the moniker, if you like.
13 MR. PAUL CHERNICK: Okay. I -- I've
14 been reading over your -- your testimony. It seemed
15 to me that any place where you talk about economic
16 identity, you could talk -- you could have replaced
17 that with 'cost causation'.
18 And maybe what you just told me was
19 that you think cost causation is used a little bit too
20 loosely, and so you wanted to come up with a word that
21 meant Patrick Bowman's more specific categorization
22 of cost causation.
23 Is that sort of what economic identity
24 is trying to get at?
25 MR. PATRICK BOWMAN: Well, more

1 specific categorization. For example, when -- when
2 Hydro says, Exports didn't cause Keeyask. Okay.
3 Exports -- there -- that's based on a premise that
4 someday we'll need Keeyask anyway and exports give the
5 opportunity to do it sooner, but -- but it's not
6 causing it, darn it. Domestic customers cause
7 Keeyask.
8 And I'm looking at this evidence and
9 saying, As far as I can see, domestic load will
10 eventually, if you accept the load forecast, require
11 some form of generation. The fact that that
12 generation is Keeyask is because of exports. But for
13 exports, that generation would not be Keeyask. It
14 would be something else, like -- like natural gas down
15 south or -- or any number of other alternatives.
16 So exports -- someone could say exports
17 didn't cause Keeyask, and I can say, Well, but in my
18 mind, exports did cause Keeyask, because if it weren't
19 for exports, there wouldn't be Keeyask. So did it
20 cause it or didn't it cause it? Well, all of a
21 sudden, cause didn't give us -- it didn't -- it didn't
22 resolve the debate, because both people are claiming
23 the -- the ground of cause.
24 And I was just trying to say, Okay, so
25 then can we get beyond that a bit and say, well --

1 pierce this veil and say, But what's really going on?
2 What is inherent in the decision to build Keeyask,
3 build it when we did, build it the size we did, build
4 it as opposed to alternatives. Let's get though the -
5 - the meat of that and -- and try to track something
6 about what is the -- the overall justification.
7 MR. PAUL CHERNICK: Okay. But I -- I
8 think you've -- you've answered my question, that
9 economic identify is your way of -- of -- your term
10 for focussing on underlying cost causation. And that
11 -- that it -- it -- and every time you talk about
12 economic identity, you wind up talking about, Well,
13 what caused this cost? How did -- how did this come
14 to be? How -- why are we still doing it? How is it
15 being used now? Is that relevant to this particular
16 item?
17 MR. PATRICK BOWMAN: Right. It's not
18 trying to refute the cause of a cost causation. It's
19 just trying to put some -- some meat on the bones, or
20 something behind it. It's still about what causes the
21 cost, but as I said, if you don't -- if you don't get
22 a bit more meat on the bones, you know, two (2) sides
23 end up -- end up shouting at each other about, Did
24 exports cause Keeyask? And -- and both of them are
25 right. They're just using cause as -- to mean

1 different things.

2 MR. PAUL CHERNICK: Right. Okay.

3 Yes, I -- I und -- I understand that part. So did you

4 imply -- mean to imply a hierarchy among the various

5 cost causation concepts that could underline your

6 economic identity? I mean, is it first you look at

7 the original justification, and only where that

8 somehow is no longer relevant, then you look at how

9 the asset or cost is being used today?

10 MR. PATRICK BOWMAN: If there is a --

11 a hierarchy, it probably has at least three (3) steps.

12 The -- the first would be: What is the rationale for

13 continuing to incur the cost today? For something

14 like Brandon -- Brandon coal, the rationale for

15 continuing to incur the cost is to backup droughts.

16 Sometimes that may not be determinative.

17 What was the reason it was originally

18 planned or was integral to the business case would --

19 would be a -- a second piece. That can help us

20 understand things like generation-weighted

21 transmission.

22 And somewhere way on down the line,

23 usually better suited to determining which classes

24 will be allocated an asset than -- than which way to

25 functionalize, classify, and allocate the asset would

1 be things like how is it used in the -- in the given
2 scenario that's in the Cost of Service Study.
3 So, yeah, I think that's a -- that's a
4 -- I -- I hadn't designed it with that -- necessarily
5 writing it down as that hierarchy, but I think that's
6 probably a fair description of it.
7 MR. PAUL CHERNICK: Okay. In response
8 to one (1) of Mr. Harper's questions, you referred to
9 using a cost of service study to determine that a
10 class costs four (4) cents a kilowatt hour to serve
11 one (1) year, and six (6) cents a kilowatt hour the
12 next year, and then what are the -- the implications
13 of that for revenue allocation, or rate design?
14 And just a little while ago, you -- you
15 referred to one (1) allocation as right as opposed to
16 all the other ways you could view cost causation. And
17 -- and I guess this is a two (2) part question. When
18 you say a class costs a certain amount, does that
19 really mean would equitably be allocated that amount
20 or -- I mean, isn't it the case that -- that what a
21 class costs now as is true for cost causation is a
22 matter of how you look at it?
23 If this were the only class, if this
24 were -- if this class disappeared, how much would we
25 save. There are a lot of ways of looking at cost.

1 And what we're really trying to do in this process is
2 figuring out what's a fair way of splitting up a pot
3 of costs that have to be covered.
4 MR. PATRICK BOWMAN: That's a long
5 question.
6 MR. PAUL CHERNICK: It is. And I know
7 that you like to give short answers.
8 MR. PATRICK BOWMAN: Yeah. Maybe.
9 No, sorry. So the purpose is to find a fair way to
10 carve up the costs. The fair way should be linked to
11 cause, cost causation. As I said, we're not throwing
12 that out the window by any stretch of the imagination.
13 Given uses cause certain costs and, as
14 a result, the -- the costs associated with that use
15 over time, that -- that planning scenario, should be
16 allocated to those classes. And there was one (1)
17 other piece of your question.
18 MR. PAUL CHERNICK: My real -- my real
19 question was: Is it -- is it really appropriate to
20 say the Cost of Service Study tells us how much it
21 costs to service a class, or does it just tell us what
22 will be a fair way of splitting up costs, many of
23 which have all kinds of entanglements between classes,
24 and over time, and are not specifically being caused
25 by this class today or this class maybe ever?

1 MR. PATRICK BOWMAN: Well, I -- I
2 think they're the same thing. What -- what it costs
3 to serve a class is -- is -- comes out of an activity-
4 based analysis like the Cost of Service Study. I -- I
5 -- you know, do -- what does it cost to serve the
6 class is a fair apportionment of the costs that exist
7 today. That -- that links to costs that are incurred
8 and -- and embedded in the system.
9 That's different than something like an
10 incremental cost. You give the example of a cost
11 class going away. Well, if -- if, for some reason,
12 the entire small business sector of Manitoba shut down
13 and jumped off the system, there would be an
14 incremental change in costs as a result of them
15 jumping off, but it would be fairly small compared to
16 the overall system. It would shock the heck out of
17 everyone else.
18 That doesn't mean that they're not
19 causing -- it doesn't cost a lot to serve them. It
20 just means the incremental change as a result of that
21 occurring over a -- a short period is different than -
22 - than the overall cost to -- to serve them.
23 But that -- you know, we dealt with
24 that in -- for example, in Yukon when the big mine
25 closed, and we had a 40 percent drop in load, so tho -

1 - those things happen. But incremental is different
2 than average or -- or embedded.
3 MR. PAUL CHERNICK: Okay. But in --
4 in that case in the Yukon, where suddenly rates went
5 up to all the remaining customers, it wouldn't have
6 been appropriate to say, well, this is what it costs
7 to serve the residential class, or the -- the
8 remaining mining load or whatever, because it's not
9 really that they're imposing those costs, it's that we
10 have a -- a pile of costs that need to be split up
11 somehow, and this would be a fair way to do it, given
12 that we now have this problem?
13 MR. PATRICK BOWMAN: Well, and but --
14 well, we -- Mr. Harper and I went through the -- the
15 principles part where I was going through what Hydro
16 lists as its goals. And it's consistent with what I
17 have experienced as goals, and is -- is in NARUC
18 manuals and Bonbrights, which, step 1 is you got to
19 recover the revenue requirement.
20 So when the mine dropped off, the
21 revenue requirement went down, but not -- not as much
22 as -- as some people in Yukon might have liked, so you
23 have to recover that revenue requirement. Given that
24 revenue requirement, how much of that cause is -- is
25 appropriately part of -- of a given -- of a given

1 class's allegation? That's where the fairness and the
2 -- the equity components come in.
3 And -- but you got to be -- also be
4 really careful about -- about mixing this embedded and
5 incremental type of analysis, or else you start to get
6 into things like we did with the energy intensive
7 rate, where -- where people concluded that -- that it
8 -- it wasn't -- it eventually rejected that, but that
9 -- that if you had a -- a load growth by one (1)
10 class, the new customer was causing the -- the
11 generation. The new customer's causing the loss of
12 exports.
13 All the existing customers are fine.
14 They're been here forever. So, you know, that -- you
15 know, Elmwood (phonetic) is using Pointe du Bois.
16 It's -- it's Linden Woods that's using -- using Long
17 Spruce or some -- some sort of long vintaging things
18 that -- that just don't have any place in this type of
19 -- in this type of model.
20 MR. PAUL CHERNICK: Okay. Moving on
21 to another point. You -- you look at what you say
22 would be the cost of peaking capacity if that had been
23 built in lieu of -- of Wuskwatim, and, you know, if
24 only peak demand needed to be met.
25 But are there specific generation costs

1 that were incurred to meet peak demand but were not
2 needed for energy that you can identify in -- in
3 Manitoba?
4 MR. PATRICK BOWMAN: Well, this is
5 where Mr. Harper and I went through the sweater
6 example, that Manitoba Hydro's system functions in
7 different ways depending on the water flow.
8 And so can you point to one (1)
9 individual asset? You said, If it weren't for peak
10 demand, we never would have built that one (1) thing.
11 I can't.
12 I think there may be some examples of -
13 - of things like system supply enhancements where a --
14 a turbine -- another turbine was added or a turbine
15 swapped out that gave you more capacity or -- or --
16 and so you can get to sort of a -- a pure benefit.
17 But it's -- it's rare that you'll find
18 something that is all about one or all about the
19 other. That's why I said you -- you should be looking
20 at a mix.
21 MR. PAUL CHERNICK: Okay. But you've
22 -- I mean, you -- you've agreed that if all you were
23 concerned about was meeting one (1) or twelve (12) or
24 sixty (60) hours a year, the hydro plants wouldn't
25 have been built, at least not the recent ones, and

1 Manitoba Hydro would have added some gas turbines or
2 something to meet those loads.
3 So you can in that case say a bunch of
4 costs were due to energy that we would never have --
5 have invested in if our only concern were peak
6 demands.
7 And I'm just asking whether you can
8 turn around and say the converse, that there are
9 actually generation costs that were incurred to meet
10 peak demand that weren't necessary for meeting the
11 energy requirements?
12 MR. PATRICK BOWMAN: Well, I'm -- I'm
13 talking about the fact that the generation system
14 produces two (2) products. It does both. Both --
15 MR. PAUL CHERNICK: All right.
16 MR. PATRICK BOWMAN: -- almost every
17 component of it does both. Wind is an exception.
18 Wind only does energy, but almost every other
19 component does both.
20 And people get into the debate about,
21 No, no, I want to see an absolutely pure capacity
22 product and everything else is energy. Or somebody
23 says, I want to see the absolutely pure energy product
24 and everything else is capacity.
25 Well, the absolutely pure energy

1 product is 1 kilowatt hour delivered whenever during
2 the year I want to deliver it. It doesn't matter.
3 You don't get to specify a time on it, or -- that --
4 that's some -- some absolutely crystal clear, pure
5 energy product.
6 The absolutely crystal-clear demand
7 product is just that kilowatt employed at peak hours,
8 and eight thousand seven hundred and -- and fifty-nine
9 (8,759) hours a year I don't care. And those are --
10 those are very much a mug's game analysis because it's
11 a mixed product type of system. It does both.
12 MR. PAUL CHERNICK: Okay. But the
13 classic -- it's a joint product. You -- you build a
14 dam, you get capacity, you get energy.
15 MR. PATRICK BOWMAN: Right.
16 MR. PAUL CHERNICK: The classic
17 example of a joint product is meat and leather from
18 steers. And in some markets, the meat is very
19 valuable and you're raising steers for the meat. The
20 skins are basically a byproduct. There's a glut on
21 the market, you sell them basically at the cost of --
22 of getting them off your hands.
23 And -- and at other times, conceivably,
24 the leather could be driving it. If -- if instead of
25 steers you're raising alligators, the leather's very

1 valuable. The meat is much less so. Maybe you're
2 selling the meat basically to cover your costs of --
3 of otherwise having to dispose of it, and the -- and
4 the leather is really driving how many alligators you
5 raise.
6 And the real question here is: What
7 part of the cost of the -- I think is: What part of
8 the cost of Hydro's generation system is due to having
9 to meet peak demand, and how much is due to having to
10 produce the energy?
11 THE FACILITATOR: I hate to interrupt,
12 but our theme for this one is -- is wool. So perhaps
13 sheep and wool would have been the joint product.
14 MR. PAUL CHERNICK: Okay. So remove
15 all references to -- to leather and make it wool and -
16 - and -- but the meat remains the same, right? Okay.
17 Anyway. Maybe we should move on.
18 Just a bit of clarification about your
19 example. You -- you said that the peaker would cost a
20 hundred and thirty dollars ($130) a kilowatt year and
21 Wuskwatim costs five hundred and sixty (560). And you
22 said one (1) of the reasons for that difference is
23 that the peaker has a shorter life.
24 Do you know what life was used in that
25 calculation?

1 MR. PATRICK BOWMAN: No. It may be on
2 the slide. Hydro ran those numbers, not me.
3 MR. PAUL CHERNICK: Yeah.
4 MR. PATRICK BOWMAN: Their -- it's in
5 their presentation. But the -- the key is that it --
6 it should be a levelized cost, not a -- not comparing
7 --
8 MR. PAUL CHERNICK: Okay.
9 MR. PATRICK BOWMAN: -- capacity.
10 MR. PAUL CHERNICK: Okay. And are you
11 aware of how old the -- well, how long the peakers
12 that have -- that were built in the 1970s, for
13 example, how long they've lasted?
14 MR. PATRICK BOWMAN: No. Like I said,
15 I didn't get into the life piece. I -- I did look at
16 the levelized cost. And there was -- there was one
17 (1) place where Hydro quotes the cost of peakers in
18 the presentations from the workshop. There's another
19 where they quote it in the IRs, where they seem to
20 update it for NFAT values. And they're not exactly
21 the same, but -- but I have no reason to think that
22 they were, at the end of the day, much different.
23 So the essence being, you know, this --
24 one (1) peak cost will not change the world in terms
25 of how things are done adopting a method. It says

1 we're going to put a fairly limited portion of demand.
2 We have some estimates about that limited portion
3 being in the range of -- of, I say, twenty-one (21) to
4 twenty-three (23), Mr. Harper cites fifteen (15),
5 adopting something like that today, but -- but then
6 sending people off to actually do the -- do the
7 homework on it and come back with something that can
8 be substantively debated.
9 That -- that's why we went that
10 direction in the -- in the pre-filed testimony.
11 MR. PAUL CHERNICK: Okay. On page 22
12 you interpret a position in Hydro's NFAT business case
13 for Keeyask and Conawapa. And your interpretation
14 seems to be that those plants were selected over gas
15 because of -- they provided higher reliability.
16 Is that what you're saying there?
17 MR. PATRICK BOWMAN: Well, it's in
18 Chapter 13 of the NFAT business case --
19 MR. PAUL CHERNICK: Yeah.
20 MR. PATRICK BOWMAN: -- which means
21 it's part of what's -- what's called the -- the social
22 account, I believe, or something. And Hydro -- and
23 Hydro never included these benefits in the economics
24 because they were not part of the utility economics.
25 But what they're effectively saying is,

1 if they built Keeyask and Conawapa, Hydro has a
2 reliability standard, a generation reliability
3 standard they try to meet. If they built Keeyask and
4 Conawapa together and it's part of the preferred
5 development plan, they would put way more megawatts on
6 the system than the standard.
7 And, as a result, they would pro --
8 deliver improved reliability compared to the standard
9 they were trying to meet and that improved reliability
10 had a value to customers. So they went through an
11 exercise to try to input a value that's associated --
12 a customer value associated with that which is not --
13 would never show up in Hydro's books. It's just a --
14 it's just a -- it looks at the cost of outages to
15 customers and things and they come up with a not
16 insignificant NPV associated with that.
17 MR. PAUL CHERNICK: Now, doesn't the -
18 - the discussion that you're citing there actually say
19 that it's the interconnections with the US that add to
20 the -- the reliability? I could read to you the
21 section if you -- you need me to.
22 MR. PATRICK BOWMAN: You can. I -- I
23 know the interconnection with the US does -- improves
24 reliability. But there was -- the -- the graph I'm
25 referring to, I can picture in my head, bring it up if

1 you like, it had distinctly two (2) steps as each
2 generating station came in that -- that jumped it up
3 ahead of the -- of the line for -- of standard.
4 MR. PAUL CHERNICK: Well --
5 MR. PATRICK BOWMAN: If you want to
6 find it, it's Chapter 13 of the NFAT business case.
7 But I don't -- I don't think...
8 MR. PAUL CHERNICK: Okay.
9 MR. PATRICK BOWMAN: I don't know
10 whether you -- you'd have that.
11 MR. PAUL CHERNICK: Well, perhaps for
12 the clarity of the -- the record, maybe -- could we
13 make an undertaking to -- to put that graph into the -
14 - the record?
15 MR. PATRICK BOWMAN: Okay, so the dam
16 has broken. I have to take an undertaking.
17 MR. PAUL CHERNICK: It's -- it's a
18 real simple one --
19 MR. PATRICK BOWMAN: Yes, but it will
20 be about the -- I'll put in the graph, but I'll also
21 review for the text you talked about --
22 MR. PAUL CHERNICK: Or -- or -- and
23 you can - - you can put in whatever pages around it
24 that are relevant.
25 MR. PATRICK BOWMAN: Sure. Thank you.

1 --- UNDERTAKING NO. 31: MIPUG to provide the graph
2 from chapter 13 of the
3 NFAT business case, and
4 comment on it
5
6 MR. PAUL CHERNICK: It's my reading of
7 it, just to -- to let you know, that Keeyask plu --
8 plus gas does not provide the -- the same level of
9 reliability as Keeyask plus the inter-tie. And the
10 text emphasizes the interconnection as being critical
11 on page 26.
12 MR. PATRICK BOWMAN: Yeah.
13 MR. PAUL CHERNICK: Boy, somebody is
14 fast here.
15 MR. PATRICK BOWMAN: I think if you --
16 yeah, there's a graph further down.
17 MR. PAUL CHERNICK: It's -- yeah, the
18 dis -- the discussion is on page 26 --
19 MR. PATRICK BOWMAN: Oh, sorry.
20 MR. PAUL CHERNICK: -- the bottom of
21 page 26, yeah, a smaller interconnection. And Keeyask
22 has greater load-serving capability than the
23 alternatives without a new interconnection. And one
24 (1) of those has Keeyask in it but not the
25 interconnection?

1 MR. PATRICK BOWMAN: The
2 interconnection combined with the additional hydro
3 resources contributes to much higher liability. If --
4 there's a graph. I think it's probably page --
5 MR. PAUL CHERNICK: The graph is on
6 the next page, yes.
7 MR. PATRICK BOWMAN: So purp -- this
8 is the -- the black line is the Manitoba Hydro load
9 that one (1) would need to have the carrying
10 capability and the -- the capability of each of the
11 plans is shown there in relation to the black line.
12 And that's what I was talking about.
13 Some -- some of the plans offered a lot more load
14 carrying capability as compared to the Manitoba Hydro
15 load than -- than like an all gas, which is being
16 driven. You'll see the blue line.
17 All it's trying to do is follow the
18 black line. That -- that's how you decide when to
19 build more gas. Whereas if you build the Keeyask and
20 Conawapa you get that purple line and it gets one (1)
21 bump for Keeyask and the interconnection, which
22 admittedly is larger, and second bump for Conawapa,
23 which is somewhat smaller, because it doesn't come
24 with new -- new interties, but --
25 MR. PAUL CHERNICK: Right, and --

1 MR. PATRICK BOWMAN: -- but that's the
2 -- that's the essence of what I was talking about.
3 MR. PAUL CHERNICK: And the case with
4 Conawapa in -- in 2022 does have one (1) small bump,
5 but then basically just follows the -- the line. It's
6 the Conawapa plus the 250 megawatt interconnection
7 that gives us the green line which has the much higher
8 reliability?
9 MR. PATRICK BOWMAN: The green line is
10 Keeyask in 2019, gas in 2024, and the smaller
11 intertie. So if you look at the green versus the
12 purple --
13 MR. PAUL CHERNICK: M-hm.
14 MR. PATRICK BOWMAN: -- the -- the
15 bump up in the green in 2019 would be adding Keeyask.
16 The extra bump up in the purple would be bringing the
17 -- the intertie. And then the subsequent purple bump
18 up that -- that doesn't really come in the green one
19 (1) is -- is adding Conawapa.
20 I'm not sure why the green one (1) adds
21 something in -- oh, gas in 2024. It adds a gas unit
22 then. And I can't recall why that gas unit is needed.
23 But nonetheless, a gas unit is added in 2024 that --
24 that does raise the green line a bit, but you see how
25 that compares to the Conawapa.

1 So it's -- I -- I would say, you know,
2 there's some transmission component. Probably more of
3 it's generation than transmission, but both are
4 relevant.
5 MR. PAUL CHERNICK: Okay. But you're
6 not saying that this analysis was the basis for
7 deciding -- well, it certainly wasn't the basis for
8 deciding to build Conawapa, because Conawapa wasn't
9 built, and it wasn't the -- the basis for building
10 Keeyask?
11 MR. PATRICK BOWMAN: No, no, no. Not
12 at all. Nothing -- because it's in Chapter 13 it was
13 more about the -- the sort of other benefits part. It
14 wasn't even in the core business case.
15 MR. PAUL CHERNICK: Okay. So it's a
16 spillover. It's a -- it's a joint product. If you
17 build these plants for the energy you also get the
18 capacity. Yeah, okay.
19 MR. PATRICK BOWMAN: I -- I -- if you
20 build -- yeah, if you build the -- the plants you get
21 both products, yes.
22 THE FACILITATOR: And does this answer
23 the undertaking?
24 MR. PAUL CHERNICK: Well, would it be
25 useful to have this figure in the record?

1 MR. PATRICK BOWMAN: I'll -- I'll do
2 the undertaking. I'll put this -- this -- I'll put
3 the -- the pages and the -- the figure and I can deal
4 with the -- the comments and text we didn't get to go
5 through since then.
6 THE FACILITATOR: Thank you.
7 MR. PAUL CHERNICK: I'd like to move
8 onto your discussion of Bipole III. And isn't the
9 reason that Bipole III was ever considered the fact
10 that you have these big generators way up north? And
11 you put them way up north because that's where the low
12 cost energy of the hydro resource is?
13 MR. PATRICK BOWMAN: Yes.
14 MR. PAUL CHERNICK: Okay. So Bipole
15 III is required by the decision to build Hydro in the
16 far north for energy saving purposes? If instead of
17 building those plants there you'd built gas combine
18 cycles in the Winnipeg area you wouldn't be talking
19 about Bipole III?
20 MR. PATRICK BOWMAN: Well, generally
21 Bipole III only arises because you have an overall
22 northern development complex an a southern load
23 complex.
24 MR. PAUL CHERNICK: Right.
25 MR. PATRICK BOWMAN: That -- yeah,

that -- that's true. That's -- that's how transmission works.

MR. PAUL CHERNICK: Okay. Now, you provided a graph of the -- of the shortage -- capacity shortage for -- without Bipole III potential and I'm just trying to find that now.

MR. PATRICK BOWMAN: Page 31.

MR. PAUL CHERNICK: Thank you.

(BRIEF PAUSE)

MR. PATRICK BOWMAN: I'll just remind people this is a graph from the Manitoba Hydro's Clean Environment Commission filing for Bipole III, the Need and Alternatives component and it's focusing on the blue part being the load that can be carried by Manitoba Hydro if Bipole I and II or -- were -- were knocked out.

And the green line focuses on the -- the load that exists in the -- southern Manitoba that's -- that benefits from the bipoles.

MR. PAUL CHERNICK: Okay. Now, looking at this it -- it looks to me like going all the way back to 1985 there was a capacity -- a peak deficit without Bipole I and II.

1 MR. PATRICK BOWMAN: Yeah, at that
2 time there was a peak deficit. Correct.
3 MR. PAUL CHERNICK: And that rose up
4 into, you know, about 1990 and then it's -- it's
5 bounced around and it's grown -- but there was a
6 deficit right from the beginning?
7 MR. PATRICK BOWMAN: Right. And if
8 you look you'll see that other things have been done
9 other than Bipole III to bring up the blue line, which
10 -- some of which improve the -- the load capability
11 absent Bipole I and II. But there was -- yeah, there
12 was a deficit.
13 Remember, the green line is the -- is
14 the -- like the peak hour of the year. So there was a
15 deficit but it -- you know, it -- of a couple hundred
16 megawatts for some -- you know, some fairly short
17 period.
18 MR. PAUL CHERNICK: Okay. But by 1989
19 that had gone up to -- each of those little squares is
20 200 megawatts, so we're looking at 1,000 megawatts,
21 1,200 megawatts by 1989.
22 MR. PATRICK BOWMAN: Right, but right
23 -- right there --
24 MR. PAUL CHERNICK: And a similar
25 amount in -- in the -- the late '90s before the

1 peakers were put in.

2 MR. PATRICK BOWMAN: Sure, but

3 ratepayers weren't -- aren't today in this cost of

4 service study paying for a system that existed in

5 1989. They're paying for the system that exist in --

6 in 2015. So we have a system that's capability,

7 absent Bipole I and II, is around 4,400 megawatts. If

8 you draw the 4,400 megawatt line across there, you'll

9 see that it -- absent load growth that -- that was --

10 was doing the job pretty much, other than a few hours

11 a year.

12 And even then, eighty-five (85) is --

13 you know, it's -- we're talking a decade after the

14 lines came into service.

15 MR. PAUL CHERNICK: Is -- you say it's

16 forty-four hundred (4,400) --

17 MR. PATRICK BOWMAN: I'm -- I'm -- oh,

18 thirty-four hundred (3,400), I'm sorry. Did I say

19 forty-four (44)? Thirty-four hundred (3,400). I'm --

20 I'm inferring the -- the bluey-purple line at it's --

21 at it's highest out -- out -- you know, around 2015,

22 around -- or '16, around now.

23 MR. PAUL CHERNICK: So my

24 interpretation of this graph is that when -- and --

25 and you -- you pointed out earlier that -- that Hydro

1 was somewhat cash constrained and needed some federal
2 help to get Bipoles I and II built, that right from
3 the beginning they built a system that lacked a
4 certain robustness.
5 If something somehow could happen to
6 Bipole I and II simultaneously, they couldn't serve
7 peak load. And that got worse over the first several
8 years of the -- the life of the northern system. And
9 now Hydro has decided it's time to do something about
10 it. The Board agreed. It was exempted from the NFAT.
11 It's -- and they're actually doing it.
12 But the -- this was a built-in problem
13 that goes back to the beginning of the northern
14 system, isn't it?
15 MR. PATRICK BOWMAN: Well, it's a
16 question of what is the standard you're trying to
17 meet, and -- and did you need this line in order to
18 bother to have the generation up north? And I'll --
19 I'll address that in two (2) -- two (2) pieces.
20 One (1) is did you need this line in
21 order to have the generation? Obviously not. We've
22 had the generation for decades without this line. The
23 question is, does this line because of its nature
24 become integral to the generation now that we've built
25 it -- or now that we're committing to build it?

1 And it works as an integral part of the
2 generation. It's part of how you operate the system.
3 But the driver for this is not average energy across
4 the year. It is -- it is these -- these winter peak
5 loads, or winter -- winter even shoulder loads now
6 that -- that derive the need for -- for Bipole III.
7 We saw that in the -- in the other
8 graphs that aren't -- aren't here but that we went
9 through at the last workshop where other parts of the
10 year were looked at. And in -- in January absent
11 Bipole III if you lost Bipole I and II you'd -- you'd
12 been able to sort of load a fair number of hours but
13 in -- in other months of the year it's -- it doesn't
14 look anything like that.
15 And that's why at the end of the day
16 this isn't just a debate about is it like generation,
17 or is it not? It's where is it going to end up
18 allocated. And if -- if you go down the road of
19 saying it's like generation, allocate it like the
20 generation, bipoles costs end up being allocated to
21 summer peak as -- almost -- basically as much as
22 winter peak. And they'd be -- get allocated to summer
23 peak more than they get allocated to winter shoulder.
24 Well, the summer peak is not what's
25 driving this. Winter peak controls are what are

1 driving this. So the -- the math -- just it -- it --
2 the allocation just doesn't reflect the -- the value
3 or the -- the reason for the line.
4 MR. PAUL CHERNICK: Okay. So what I
5 get from what you just said is that, yes, this line
6 really was -- is a part of the northern development.
7 And it could have been built back when the northern
8 development was first undertaken.
9 And even if it had been built back
10 then, you would have said, Okay, it's generation
11 related, but it should be -- it's generation related
12 with a peak justification, not a -- a purely energy
13 justification.
14 Is that --
15 MR. PATRICK BOWMAN: It's --
16 MR. PAUL CHERNICK: -- consistent with
17 what you -- you were saying?
18 MR. PATRICK BOWMAN: -- it -- could it
19 have been built back then? I suppose, if somebody had
20 found a bunch more money, they could have built it. I
21 don't know why they would have. They didn't need it.
22 MR. PAUL CHERNICK: Well, they did
23 need if they wanted to be able to serve load all the
24 time.
25 MR. PATRICK BOWMAN: Well --

1 MR. PAUL CHERNICK: Because in -- in
2 1985, the graph shows that you're a couple of hundred
3 megawatts, 400 megawatts, short, and by '89, you're
4 1,000 megawatts short.
5 MR. PATRICK BOWMAN: They're a couple
6 of hundred megawatts short a couple of hours of the
7 year. You don't build a $3 billion line to solve a
8 couple of hundred megawatts for a couple of hours a
9 year. That -- it doesn't even -- doesn't even fit the
10 -- the bill for that type of load.
11 It wasn't -- Bipole didn't get --
12 didn't get historically to become a big deal until
13 people started talking about sell -- building Conawapa
14 and selling power to Ontario for -- in 1990, a review
15 before this Board.
16 That's when Bipole came up, and then it
17 was part of the Conawapa complex, and it was on the
18 east side of the lake, and all the other stories that
19 -- that people are aware of now.
20 But if you get right down to it, the --
21 the question is: Are you going to end up focusing on
22 some -- some word games linked around the concept of
23 causation or part of a complex that somehow whisk this
24 asset through this allocation system that says, Summer
25 peak really matters and summer shoulder really

1 matters, and -- and winter and winter shoulder are no
2 more important, when we know that's not the -- the
3 premise for the line?
4 MR. PAUL CHERNICK: Okay. I
5 understand.
6 THE FACILITATOR: Paul -- Paul, about
7 three (3) minutes --
8 MR. PAUL CHERNICK: Okay.
9 THE FACILITATOR: -- if you had a more
10 important one.
11 MR. PAUL CHERNICK: I have -- no
12 editorial comments we can call it, right? Okay. On
13 page 28, you talk about including Wuskwatim
14 transmission lines 1, 2, and 3 as being part of the
15 generation-related transmission.
16 And are those the lines from Wuskwatim
17 to the switching station?
18 MR. PATRICK BOWMAN: That -- that's my
19 understanding. I was looking at a list of assets in a
20 -- in an Excel file that I -- there's a reference to
21 the Excel file name in the footnote.
22 MR. PAUL CHERNICK: But those lines
23 wouldn't have done any good if Hydro didn't also build
24 lines from Wuskwatim to Birch Tree, Herblet Lake, and
25 Rawles Island (phonetic), right? Because Wuskwatim --

1 Wuskwatim sits -- switching station just sits out in -
2 - or would have sat out in the middle of noplace until
3 the plant was built.
4 MR. PATRICK BOWMAN: Absent
5 transmission, every substation sits out in the middle
6 of noplace. So trans -- that's what transmission
7 does.
8 MR. PAUL CHERNICK: No. Some of them
9 sit on transmission lines that were already there, or
10 right next to them. But Wuskwatim is out by itself,
11 and four (4) transmission lines were built to tie
12 Wuskwatim to the system. These three (3) lines that
13 you picked out would be completely useless and
14 Wuskwatim would be completely useless if at least some
15 of these transmission lines from Wuskwatim to other
16 places on the transmission system hadn't been built.
17 Isn't that correct?
18 MR. PATRICK BOWMAN: Yeah. I think
19 every generating station is completely useless if it
20 doesn't have transmission. That's -- that's the whole
21 premise of transmission moving -- moving bulk power,
22 and it's -- as referenced in the -- in the -- the NERC
23 manual.
24 I even put a quote in there about how
25 defines transmission, and it's basically moving power,

1 right?

2 MR. PAUL CHERNICK: As distinct from

3 distribution which just spreads it out. That's --

4 that's a useful distinction.

5 MR. PATRICK BOWMAN: Well, and that's

6 the essence of the -- of the NERC (sic) seven (7)

7 factor test. It's to distinguish between transmission

8 and -- and distribution.

9 MR. PAUL CHERNICK: You're talking

10 about the -- the FERC seven (7) factor test --

11 MR. PATRICK BOWMAN: FERC, yeah.

12 MR. PAUL CHERNICK: -- for the --

13 MR. PATRICK BOWMAN: That's it, that's

14 it.

15 MR. PAUL CHERNICK: -- that's for the

16 distinctions between transmission and distribution,

17 not just between generation and transmission.

18 MR. PATRICK BOWMAN: That's right. We

19 --

20 MR. PAUL CHERNICK: But those -- those

21 --

22 MR. PATRICK BOWMAN: -- distribution --

23 MR. PAUL CHERNICK: Right. Those

24 transmission lines would not have been built from

25 Wuskwatim to the -- the other parts of the

1 transmission system had Wuskwatim not -- not been
2 built.
3 MR. PATRICK BOWMAN: Well, I -- I
4 can't tell you that. What I can tell you is
5 Wuskwatim's transmission was its own project. It was
6 tracked as its own project, got its own environmental
7 licence, and it was clearly designed to not just take
8 Wuskwatim's energy down a -- down a driveway, to use
9 your earlier example. It was designed to add some --
10 some highway to the system that -- that among other
11 things delivers Wuskwatim's power.
12 But it's not just a matter of a -- of a
13 straight shot to the nearest substation where you can
14 connect it. It is a -- it is in addition to the
15 overall transmission complex.
16 THE FACILITATOR: Why don't we return
17 to this? If -- if we get done this section before
18 three o'clock, then we'll return first off to this
19 question.
20 MR. PAUL CHERNICK: Can I ask just one
21 (1) more question?
22 THE FACILITATOR: Okay.
23 MR. PAUL CHERNICK: With respect to
24 DSM, you talked about the conflict that can occur
25 between classes, or among classes if classes think

1 they're paying for the costs of other classes' DSM,
2 and they aren't getting commensurate benefits. And
3 you and I agree that, that can be a problem, and I
4 talk -- talk about that in my testimony.
5 I identify the converse issue where a
6 class is doing DSM at Hydro's behest because it's less
7 expensive than the avoided cost. It's good for the
8 system as a whole. But it may increase costs to that
9 class if the costs are directly assigned to them.
10 Do you see that as being a possibility
11 and, if so, do -- would that be a -- the similar kind
12 of conflict where you're asking a class to do
13 something that's good for the system but bad for the
14 class?
15 MR. PATRICK BOWMAN: So within the
16 context of the cost of service study and the revenue
17 requirements over the next fairly large number of
18 years, I think much of the DSM at the end of the day
19 is going to end up resulting in higher rates overall.
20 It's why DSM is showing up in Hydro's IFF as an upward
21 rate driver.
22 The only question is if DSM is -- is
23 resulting in rates being higher, what -- what do you
24 do about -- about tracking that higher cost or those
25 higher rates to -- against the benefits? And if a

1 program is run that -- that benefits a residential
2 class for example, or an industrial class, you have --
3 have a lot -- a lot better logic and a lot easier time
4 saying let's -- let's take that cost and -- and
5 allocate against the class that's getting those --
6 those other notional benefits so that the -- so that
7 the two (2) track.
8 If there's -- if it's supposed to be
9 overall bill savings, then -- then there should be no
10 issue with that. If it's -- if it's not generating
11 those bill savings, then at least you're trying to get
12 the -- the costs into the area where the benefits do
13 arise.
14 MR. PAUL CHERNICK: So are you saying
15 that the -- the converse that I laid out where the DSM
16 can be cost effective for the system but if you charge
17 it all to the participating class which only gets some
18 of the system benefits, it could actually be worse
19 off.
20 Are you saying that that's sort of
21 logically impossible? That you don't think it applies
22 for Manitoba Hydro? Or is it --
23 MR. PATRICK BOWMAN: No. In fact, I
24 actually say in the evidence that that kind of
25 situation arises in Newfoundland or, for example, if

1 you look at -- at BC where they have near term supply
2 constraints or they -- they did when they -- when they
3 imposed a standard that says we need to have -- be
4 able to export large amounts of assurance energy while
5 retiring Burrard and planning our system for drought
6 flows.
7 BC adopted a very high standard. They
8 were short resources. Absent the DSM they would have
9 had to build really expensive stuff in the very near
10 term, or sign on some expensive IPPs, and so the DSM
11 was -- was economic. It's -- cost is now. Benefit is
12 now. It's all included in this cost of service study.
13 In Newfoundland you do DSM on an isolated island as it
14 is now. You save some oil from the -- the oil plant.
15 The savings in the oil more than pays for the DSM.
16 You go to those types of things and you
17 say, no, that -- that DSM spending is very clearly
18 bringing with it a savings to the overall system.
19 Everyone's rates are going to be lower. The only
20 question is, who pays for those? Well, if everyone's
21 rate is going to be lower then take the cost and
22 spread it out with everyone's rates that are going to
23 be lower.
24 That's not where we are in Manitoba
25 Hydro. We're talking about a DSM that -- that might

1 pay off in -- in deferring Conawapa in -- in 2038 or
2 whatever -- whatever year it would currently be
3 targeted for. Our -- our rates are not going lower
4 because of DSM. They're going up because of DSM.
5 That's -- that's -- read the IFF. They're -- they're
6 -- it's consistently cited: DSM is one (1) of the
7 reasons why Hydro needs rate increases. Like it's not
8 my words, it's theirs, so.
9 THE FACILITATOR: Even though DSM, the
10 -- the classification and allocation of DSM is -- is
11 one (1) of the big issues in this -- in this hearing,
12 I think we need to move along at this point and -- and
13 Paul, you --
14 MR. PAUL CHERNICK: I just wanted to
15 say thank you.
16 THE FACILITATOR: I think also with
17 your presentation you can address some of Patrick's
18 commenting in your opening part there. So moving on
19 to general service.
20 MR. CHRISTIAN MONNIN: Yes. Thank
21 you. I think we're okay from here. Mr. Leslie has --
22 has a direct line of sight with -- with Mr. Bowman.
23 And, therefore, we can proceed and not force anyone to
24 move.
25

1 CROSS-EXAMINATION BY MR. JAROME LESLIE:

2 MR. JAROME LESLIE: Thank you. I want

3 to start off on a similar topic raised just by Mr.

4 Chernick. Stole kind of our thun -- some of our

5 thunder in regards to Bipole III and the

6 Functionization of some transmission assets'

7 generation.

8 So to start, Mr. Bowman, Mr. Chernick

9 asked you whether Bipole III would exist without

10 generation being in the north. And you said, No. So

11 to come back to the first princ -- first principles,

12 do you believe that transmission that built only to

13 connect the generation to the grid should be

14 functionalized as generation?

15 MR. PATRICK BOWMAN: I -- I set out

16 the first principles in the evidence. It -- it's not

17 just a test of generation or as transmission only

18 built to connect generation to the grid. It's, are

19 the transmission and the generation integrally linked

20 in a way that says, absent the transmission, I'd never

21 been able to build this generation, absent the

22 generation, I'd never been able to -- I never would

23 have built this transmission and the transmission is

24 playing no other useful role in my system beyond

25 bringing the generation to the grid.

1 If it passes all those tests, then --
2 then go ahead and functionalize it as generation and
3 think further about how you classify and allocate.
4 MR. JAROME LESLIE: Okay. I thank
5 you. So in regards to page 26 of your evidence, you
6 note Christensen's criteria for functionalization --
7 functionalizing transmission as generation. And my
8 reading is that you generally disagree with these
9 criteria.
10 Is that the case and can yo comment on
11 that? So on page 26 it describes the Christensen
12 Associates criteria from their 2012 report, and also
13 from their 2015 report.
14 MR. PATRICK BOWMAN: Yeah, I -- I saw
15 Christensen's criteria in two (2) different reports,
16 which I cited here. I think they -- they read
17 differently. They've been repositioned. Maybe
18 they're meant to mean the same thing. Christensen
19 also does not Hydro's reference, I think, to the --
20 the seven (7) factor test that Hydro tends to use.
21 I didn't think that these are
22 necessarily determinative. They're somewhat -- many
23 of these things can exist on -- on transmission in --
24 in all sorts of examples, like flows in a uniform
25 direction.

1 So I didn't think that they were
2 necessarily determinative or -- or gave one the -- the
3 clear distinction between what one would put to
4 generation versus -- versus to transmission.
5 MR. JAROME LESLIE: On that note then,
6 do -- do you see -- or find issues with the
7 application of this approach from Hydro in determining
8 GRTAs?
9 MR. PATRICK BOWMAN: I'm sorry, can
10 you repeat that question?
11 MR. JAROME LESLIE: Do -- do you
12 object to the application of these criteria in how
13 Hydro has determined generation-related transmission
14 assets outside of the Bipole III?
15 MR. PATRICK BOWMAN: I -- I don't
16 think these criteria necessarily get one to a -- to a
17 clear distinction as to what is a GRTA and what is
18 not. And -- and I think some of those examples even
19 came up at the last workshop. Like, if you had a --
20 if you had a line that -- that had a cottage
21 development at the other end of it or -- or something
22 connects to it, does it -- does it change from a GRTA
23 to not a GRTA, you get into a lot of -- of very sort
24 of weird grey areas.
25 I think the -- the essence of it is, as

1 -- as I set out, in terms of the -- the -- in -- if
2 the transmission is -- is a driveway to the generating
3 station, if it plays no other role than to deliver
4 generation to the grid, if it would have no other
5 function, if -- than that, if it wouldn't exist in any
6 other form but for the generation, then -- then it
7 would pass the test. And like I said, it should be a
8 -- it's a fairly -- normally, it's a fairly limited
9 category. It's -- it's -- like I said, it's 5 percent
10 of BC Hydro’s assets.
11 So at the end of the day, going through
12 all of these things like Is there a close -- it
13 doesn't show it on this page, but the fourth criteria
14 that spills over to the next page, Is there close
15 integration to Manitoba Hydro's generating facilities
16 in the north?
17 I don't know how that is a pass-fail
18 linkage. Is transmission in the area of Thompson
19 close? Like what -- if there's one (1) measure by --
20 by kilometres or what. I don't -- I don't -- I'm
21 sorry, I didn't find that this was necessarily
22 determinative.
23 MR. JAROME LESLIE: Okay. Thank you
24 for your response. And so touching on some of what
25 Mr. Chernick had asked before, you were making the

1 argument that Bipole III is essentially to serve the
2 peak loads in winter months.
3 Is that correct?
4 MR. PATRICK BOWMAN: No, I don't say
5 peak loads. I -- I acknowledge that we're at a point
6 where Bipole III would serve energy across not just
7 peak periods, but -- but probably also shoulder
8 periods. And so I -- I give an alternative where one
9 allocates Bipole III to -- to energy, but focusing
10 only on the -- on the winter peak and the winter
11 shoulder weighted energy.
12 And you can -- if you want to see the
13 megawatts that are associated with that, there is one
14 PUB IR that -- that gives the -- the megawatt peaks
15 associated with each of the time periods, the -- the
16 average and maximum, I think. And you can -- you can
17 see very much the pattern, that those are the -- those
18 are the -- the domestic times that are really driving
19 the -- the need for the Bipole III.
20 MR. JAROME LESLIE: And on -- touching
21 on that, so how do you expect Bipole III to run in the
22 summer?
23 MR. PATRICK BOWMAN: Oh, similar to
24 the example I gave of the Whitehorse hydro plant.
25 Bipole III would be operated by the operators in the

1 most efficient manner to -- to move power and to
2 capture export markets and to -- to, you know, ensure
3 that -- that Manitoba's energy needs are met in
4 drought and flood and average conditions, all -- all
5 the normal things that go into an -- an operating
6 decision.
7 MR. JAROME LESLIE: Fair enough, and -
8 - and thank you. Moving on to my next question, I'd
9 like to touch on DSM. And do you believe that the
10 direct assignment of costs to part -- participating
11 groups reduces the incentives of these DSM programs
12 that is the current approach taken from Manitoba
13 Hydro?
14 MR. PATRICK BOWMAN: Do I think that
15 the approach -- and when you say, "current approach,"
16 you mean the approach Manitoba Hydro is proposing,
17 direct assignment of DSM program costs to the
18 participating classes?
19 MR. JAROME LESLIE: Yeah, that's
20 correct.
21 MR. PATRICK BOWMAN: Yeah, I -- well,
22 is it a -- is it a -- a disincentive to participation?
23 I -- I don't think so. I think, frankly, I suppose,
24 if anything, it's an -- it's an incentive to
25 participation.

1 But the -- the direct-assigned DSM
2 costs, like I don't mean to -- to belabour the point,
3 but there is relatively little impact on -- on the
4 costs assigned to a class by putting DSM directly to
5 the class versus to generation at -- at this point in
6 time.
7 That could be different in the future,
8 but at this point in time, you know, the -- the
9 different classes -- the bigger classes have more DSM
10 costs. They also would get a bigger share if it was
11 allocated to -- to generation.
12 So it's not that they're radically
13 different approaches or that -- it's -- it's just a
14 matter of -- of being able to have everyone easily
15 understand and easily explain that -- that they --
16 they don't -- they -- they should want to see -- want
17 to find -- want to find a way to participate in DSM
18 that's occurring for their class because they're
19 paying for it anyway.
20 And they should not get riled up about
21 DSM occurring for another class and needing to get in
22 and really aggressively attack or review it because
23 it's not a part of their rates. It may be at the end
24 of the day their rates are exactly the same, but
25 that's a -- it's a -- it's an important cost driver

1 and -- and matter of communication to me.

2 MR. JAROME LESLIE: Okay. Fair

3 enough. And so do you agree or disagree that then DSM

4 could be seen as a substitute for generation,

5 transmission, or distribution?

6 MR. PATRICK BOWMAN: Oh, absolutely.

7 You know, usually it's mostly generation. It depends

8 on the system you're dealing with, but there are

9 situations like the two (2) I gave an example of, BC

10 Hydro and Newfoundland where DSM, or -- or a lot of

11 DSM at least, is absolutely a substitute for -- for a

12 -- a generation, or transmission, or distribution

13 assets, and -- and can be classified an allocation on

14 that basis.

15

16 CROSS-EXAMINATION BY MR. IAN CHOW:

17 MR. IAN CHOW: So following up on that

18 for Mr. Chernick's question previously, you -- you

19 mentioned that DSM is a -- is an increase in costs.

20 Is that correct?

21 MR. PATRICK BOWMAN: At -- at this

22 point the way Manitoba Hydro's DSM cycle works and

23 their -- their development cycle, if you look at

24 Hydro's rates the expansion of a DSM program and --

25 and chasing further amounts of DSM can be good for the

1 province, but it can be an upward driver on Hydro's
2 rates overall.
3 MR. IAN CHOW: When you talk about an
4 upward driver is that with respect to a do nothing
5 case, or the case where perhaps there's some
6 substitution of -- of generation investment?
7 MR. PATRICK BOWMAN: Well, I -- I
8 think the issue is that we don't have a substitution
9 of generation investment practically occurring
10 whatsoever. Keeyask is under construction. It's
11 going to be built. The other -- there's not --
12 there's not other major generation investment being --
13 being undertaken.
14 And the -- the next need for generation
15 isn't until the late 2030s the last that I've heard
16 and -- and to be consistent with the information filed
17 in the -- the last GRA. So you're not sort of getting
18 a -- a generation substitution in any -- any near term
19 period, but the issue of added DSM on rates, it's
20 different than the province overall, but on rates is
21 that the upward driver occurs whether you're talking
22 about DSM versus no DSM or more DSM versus less DSM.
23 That -- that overall is -- is linked to
24 the -- the upper driver on rates in, you know, in the
25 next number of years, maybe -- maybe a decade and a

1 half, maybe more. I -- I make the distinction about
2 the province overall versus Manitoba Hydro because the
3 province overall, people tend to talk about different
4 DSM tests.
5 And a number of those tests ignore
6 revenues to Hydro, because if you draw a bubble around
7 the province and you say what is the effect --
8 economic effect of this DSM, it ignores flows that
9 only occur within the province. So it ignores the
10 fact that customers buy less energy, but Hydro
11 receives less revenue.
12 It -- that revenue piece doesn't even
13 make it in the calculations, because they -- they net
14 out within that -- that mix. But if you actually go
15 to Hydro's books and you say, They might invest a
16 penny in DSM, they might lose a -- a penny per
17 kilowatt hour, they might los -- they would lose, call
18 it seven (7) cents if it's a residential DSM, for
19 example,, seven (7) cents in revenue.
20 So now they're -- they're eight (8)
21 cents behind, and they take that energy and go to
22 market and sell it for three (3), they're five (5)
23 cents behind. That's the -- that's the picture in
24 their financial forecast from DSM in this -- in this
25 near term horizon.

1 Now, if you want to ignore the seven
2 (7) because that's just a transfer in the province,
3 that -- that tells you that overall within the
4 province we're spending a penny to get three (3). But
5 the -- the distribution of those as opps -- in
6 Manitoba Hydro's books versus the overall province are
7 -- are distinct and lead to the upward rate drivers
8 I'm talking about.
9
10 CONTINUED BY MR. JAROME LESLIE:
11 MR. JAROME LESLIE: Okay. Thank you.
12 And the last topic that we want to ask about was
13 related to net export revenue. And in your evidence
14 you believe that it shouldn't be part of the cost of
15 service methodology.
16 And my question is: If you were to
17 hold a -- an ER in reserve, have you given thought to
18 how the -- the PUB would decide to use it and would
19 there be additional oversight necessary and?
20 MR. PATRICK BOWMAN: Oh, we've given
21 years of thought to it and a fair bit of evidence over
22 different GRAs. I've provided an exhibit about some
23 ways that -- that people could think about doing it.
24 Mr. Williams will remember crossing me -- cross-
25 examining me about the PUB having, I forget what he

1 called it, one (1) -- one (1) lever of control, where
2 they can either raise rates or lower rates.
3 And if they -- they think Hydro's
4 reserves are too low, but their costs are too high,
5 what do they do, raise, or lower, or what -- what do
6 they do? And -- and we talked about mechanisms where
7 some could use this net export revenue to -- to design
8 a system where you actually can increase the PUBs
9 leverage control perhaps to two (2) rather than one
10 (1) by defining certain transfers that could occur to
11 reserves that are under the PUB's jurisdiction.
12 We could find a way that you could
13 build up a -- a better type of reserve fund that's
14 able to help ensure more stable rates in the future.
15 Christensen cited that. Their -- their example was
16 when cap -- big capital comes in. My example was
17 drought. But you could build up some reserves. Then
18 we control the PUB that they decide to -- to manage as
19 needed to help -- help keep rates stable.
20 Yeah, there's -- I think there's a lot
21 of things. The -- the key is that in -- in the
22 evidence I've prepared, if you accept all of the
23 recommendations, there's about 50 million in net
24 export revenue, according to the models Hydro sent me.
25 I had calculated that as fifteen (15), but I was

1 missing one (1) step.

2 So there's about 50 million in net

3 export revenue. The key is that 50 million doesn't

4 exist until you run the Cost of Service Study based on

5 these methods, and then move on and adjust your rates

6 over time to bring up those classes who are below a

7 hundred to actually free up that 50 million to then be

8 used for things like a transfer to a reserve.

9 And -- but once we've done that, you

10 isolate a lot of the -- you know, some of the

11 instability in Hydro's financial forecast, because

12 that 50 million transfer might go up or down in a

13 given year. If export markets change, if droughts

14 change, it could absorb a lot of that rather than

15 showing up in -- in big rate increases when a drought

16 occurs, which has been a concern to my clients for --

17 for many years.

18 MR. JAROME LESLIE: Okay. And

19 building on this, do you agree that this approach is

20 somewhat analogous to the policy decisions in regard

21 to the universal rate adjustment? And also the AEF

22 program where the Board essentially provides direction

23 on instructive ways of how this export revenue should

24 be used in addition to how it's currently handled in

25 the Cost of Service methodology?

1 MR. PATRICK BOWMAN: Well, they're
2 analogous and the -- I put them in the same chapter, I
3 think -- in the sense that none -- none of the three
4 (3) link to cost. The -- the uniform rate adjustment
5 links to revenues. The affordable energy fund links
6 to a one (1) time transfer that was supposed to occur
7 in -- in 2006/'07 when gas prices were -- were high
8 and Hydro had some very good export market returns.
9 They don't link to -- or they -- they ought not be
10 linked into current costs.
11 And then export revenues similarly, if
12 you're measuring costs to customers, once you've
13 assigned exports -- a -- a reasonable contribution
14 against the system, if there's additional export
15 revenue, it should be to the benefit of customers. It
16 -- it arises because of risk customers took on.
17 But it doesn't necessarily -- it
18 doesn't strike me as necessarily the smartest idea to
19 automatically funnel it back into the Cost of Service
20 study to bring down rates today $50 million a year
21 spread across the classes when -- when it could be
22 used for other -- other priority purposes.
23 So in that sense, is it a policy thing?
24 Well, it's not a cost thing, so I -- I put it into
25 that chapter under policy items.

1 MR. JAROME LESLIE: Okay. Fair
2 enough. And thank you again. And that's this last of
3 our questions for this session.
4 THE FACILITATOR: Thank you. Perhaps
5 before breaking, on that last point, Patrick, is -- is
6 not the point that you're trying to make is that the
7 net export revenue is a rate design matter rather than
8 a cost of service matter?
9 MR. PATRICK BOWMAN: Yeah. You --
10 that's the -- the point I made first in the bullets of
11 the slide, that you -- this should be a tool that --
12 that measures costs. Funnelling back this revenue
13 that's not linked to costs just muddies up what the
14 Cost of Service Study is trying to do, which would be
15 measuring what it costs to service each class.
16 If you -- at the end of the day, you
17 have a bunch of net export revenue you want to give
18 back this year, and as a result, people don't pay
19 their cost, that -- that's a rate design matter, sure.
20 THE FACILITATOR: Thanks. Well, we're
21 back on time, so why don't we take our lunch break.
22 Well, let's -- let's take our lunch break till the
23 current plan on the -- the schedule, back to one
24 o'clock. Thank you.
25

1 --- Upon recessing at 11:50 a.m.
2 --- Upon resuming at 1:04 p.m.
3
4 THE FACILITATOR: All right, Patrick.
5 I see Denise has arrived, so we all good now.
6
7 (BRIEF PAUSE)
8
9 CROSS-EXAMINATION BY MS. DENISE PAMBRUN:
10 MS. DENISE PAMBRUN: Thank you, Mr.
11 Grant.
12 Mr. Bowman, I just want to make sure
13 you have your report handy.
14 MR. PATRICK BOWMAN: Yes.
15 MS. DENISE PAMBRUN: Can we start at
16 page 12, please?
17 MR. PATRICK BOWMAN: Yes.
18 MS. DENISE PAMBRUN: I guess just
19 before I start, I should let you all know that when I
20 advised Mr. Peters that I was going to be asking the
21 questions today on behalf of the City, I found out I
22 was the only lawyer who had been advised or requested
23 by my client to ask the questions.
24 And Mr. Peters's first words burst out
25 of his mouth were, Be nice. Apparently Mr. Peters

1 doesn't have a great deal of confidence in my ability
2 to behave myself. So I've asked my client, Mr. Chin,
3 and my expert, Mr. Todd, to keep me under control.
4 You can all be rest assured that there's 4,000 volts
5 on this chair, and they both have buttons, fingers at
6 the ready.
7
8 (BRIEF PAUSE)
9
10 MR. PATRICK BOWMAN: I think it may
11 have been more of a comment about my fragile nature,
12 so.
13 MS. DENISE PAMBRUN: Ah. It's --
14 you're a sensitive, New Age guy, Mr. Bowman. I
15 promise to be nice, as I promised Mr. Peters.
16 So at page 12 of your report, we see at
17 line 21 the statement -- 11 and 12:
18 "It informs the PUB, but does not
19 direct rate approvals."
20 And there you're talking about the Cost
21 of Service Study. And it says there that MIPUG
22 strongly disagrees. I take it that not only does
23 MIPUG strongly disagree, but it is your opinion that
24 that statement is not your view.
25 Is that correct?

1 MR. PATRICK BOWMAN: Yes. This quote
2 was actually -- it was -- it was a quote, and it
3 didn't get inserted as a quote, unfortunately. This
4 was in a document that was prepared as a -- a MIPUG
5 submission to the pre-hearing conference, and the --
6 it took the -- noted the position of the group in
7 terms of disagreeing with Hydro about the nature of
8 the Cost of Service Study. And I think it's a -- it's
9 a -- a fair conclusion by the MIPUG group.
10 MS. DENISE PAMBRUN: All right. And
11 there have been some email exchanges between counsel
12 prior to this hearing about how the experts were going
13 to testify and what exactly was going to be the nature
14 of your testimony. I understand today that you're
15 here to express your views as an expert.
16 Is that correct?
17 MR. PATRICK BOWMAN: Yes.
18 MS. DENISE PAMBRUN: All right. And
19 so if there was an area in which you gave expert
20 evidence, and your client happened not to agree, you
21 would be in a position to advise us of that?
22 MR. PATRICK BOWMAN: Not necessarily.
23 MS. DENISE PAMBRUN: Okay. Fair
24 enough. Now, you also go on to say on the same page
25 that a cost of service study does not direct rate

1 approval -- I'm sorry, you say that Manitoba Hydro has
2 indicated in its material that a cost of service study
3 does not direct rate approval. That's stated on line
4 -- lines 20 and 21.
5 Do you see that at page 12?
6 MR. PATRICK BOWMAN: Yes. That's
7 Hydro's quote, yes.
8 MS. DENISE PAMBRUN: That's correct.
9 And you say that you don't agree with that. And can
10 you explain to me exactly what you mean by that?
11 MR. PATRICK BOWMAN: Well, the piece
12 that -- that I -- I was echoing what the -- the
13 members had -- had said, and that I agree with, is
14 that Hydro's overall statement is that a cost of
15 service study is much like an integrated financial
16 forecast. And so it informs the PUB but it's just one
17 (1) of these documents that we review, and -- and put
18 in an appendix. And -- and I think that's the part
19 that -- that I disagree with, and the members disagree
20 with.
21 An integrated financial forecast is a
22 normal type of document any -- any business would
23 produce. It's useful for internal purposes. It's
24 informative. It -- it gives an idea about where the
25 company is going. A cost of service study is

1 something different than that, in -- in my view.
2 A cost of service study is -- is only
3 about regulated utilities. You won't have a --
4 probably a trucking company or something having a cost
5 of service study. And it's -- it's only really for
6 the purpose of -- of setting rates. I know a lot of
7 utilities who operate for years without running a cost
8 of service study.
9 So unlike an IFF, which is a document I
10 would expect any business would have and probably
11 updated quarterly, a cost of service study is really a
12 unique regulatory thing. It's mostly about a PUB type
13 of setting.
14 MS. DENISE PAMBRUN: And you would
15 agree with me a cost of service study is a necessary
16 document for setting rates in that it -- it forms a
17 part of the equation that ultimately leads to a bill
18 for a client. Is that right?
19 MR. PATRICK BOWMAN: Yes.
20 MS. DENISE PAMBRUN: Okay. And I
21 think it probably goes without saying that ratepayers
22 in the Province of Manitoba have to have confidence in
23 the cost of service study. Is that right?
24 MR. PATRICK BOWMAN: Yes.
25 MS. DENISE PAMBRUN: But it's also

1 fair to say that as an expert, you know that there's
2 no absolute right or wrong to any one (1) of the
3 various principles that go into a cost of service
4 study. Is that right?
5 MR. PATRICK BOWMAN: For -- sometimes
6 there are principles that are right or wrong, but a
7 good part of the cost of service study is made up of
8 things where there's room for judgment.
9 MS. DENISE PAMBRUN: Right. Fair
10 enough. And the decisions on those judgment calls, it
11 depends on the circumstances. Is that right?
12 MR. PATRICK BOWMAN: That's fair.
13 MS. DENISE PAMBRUN: Okay. Now, I'd
14 like to talk to you a little bit about this issue that
15 arose this morning about the inclusion of net expert
16 reve -- net export revenue in the cost of service
17 study as opposed to the exclusion of it, and it being
18 potentially set aside in some reserve fund or
19 something like that.
20 Do you recall that discussion?
21 MR. PATRICK BOWMAN: Yes.
22 MS. DENISE PAMBRUN: Okay. So I'd
23 like to draw your attention -- and I'm certain you're
24 aware of this, that there are other types of revenue
25 that the Utility may have, one (1) of them for

1 instance being -- an example would be revenue say from
2 late payment fees from customers.
3 You're familiar with that?
4 MR. PATRICK BOWMAN: Yes.
5 MS. DENISE PAMBRUN: Okay. So that's
6 an example of a type of revenue which is not directly
7 from the sale of -- of hydro electric power from
8 customers. Is that correct?
9 MR. PATRICK BOWMAN: Yes.
10 MS. DENISE PAMBRUN: Okay. And my
11 understanding of that revenue is that it is netted
12 out, that is the costs of providing that or of
13 obtaining that revenue is netted out against the
14 revenue and then ultimately the net revenue, if there
15 is any, or the net cost if that's the result is
16 included in the cost of service equation, if I can
17 call it that.
18 Is that your understanding?
19 MR. PATRICK BOWMAN: I think the --
20 the -- to use the word 'net' the net effect is the
21 same whether it's -- I'll -- I'll leave it at that.
22 The -- the order of the steps may vary but the net
23 effect is the same.
24 MS. DENISE PAMBRUN: Right. And --
25 and the net whatever it is, revenue or cost, is

1 included in the cost of service. Is that correct?
2 MR. PATRICK BOWMAN: Yes.
3 MS. DENISE PAMBRUN: And that's also
4 true of revenue that the Utility might receive from
5 something like pole attachment fees. Is that correct?
6 MR. PATRICK BOWMAN: Yes.
7 MS. DENISE PAMBRUN: And pole
8 attachment fees, if I understand, are fees that the
9 Utility would generate from non-hydro electric
10 customers say from, and correct me if I'm wrong, say
11 MTS because there are poles throughout the Province.
12 And other users might find it beneficial to use those
13 poles, so they would pay fees to Manitoba Hydro to use
14 those poles.
15 Is that correct?
16 MR. PATRICK BOWMAN: Yes.
17 MS. DENISE PAMBRUN: And my
18 understanding is, similar to late payment fees, those
19 -- that revenue -- there's a net effect of the cost
20 and revenue from that, and that revenue is also -- the
21 net effect of that revenue and cost is also included
22 in the cost of service study.
23 Is that correct?
24 MR. PATRICK BOWMAN: Yes.
25 MS. DENISE PAMBRUN: So those are some

1 examples of revenue that the Utility generates from --
2 not from the sale of hydro electric power, and that --
3 those forms of revenue are netted out and included in
4 the Cost of Service Study.
5 Have I --
6 MR. PATRICK BOWMAN: Yes.
7 MS. DENISE PAMBRUN: -- summarized
8 that correctly?
9 MR. PATRICK BOWMAN: Yes.
10 MS. DENISE PAMBRUN: And a third
11 example of revenue that the Utility can generate, this
12 time from the sale of power, but not to domestic
13 customers is what we've been referring to as net
14 expert -- export revenue, correct?
15 MR. PATRICK BOWMAN: Well, overall
16 export revenue, but -- but, yes, the -- the only
17 distinction being that in the case of -- of pole
18 rentals, we don't have a pole rental customer class
19 that we assign pole costs to and then look at how much
20 of it is covering costs versus how much is above costs
21 and think about treating them differently.
22 Exports would be different because we
23 have this class and because we incur costs associated
24 with exports. But, yes, in general, yes, I agree with
25 you. The -- it's -- it's this non -- non -- it's a

1 function not related to serving Manitoba domestic
2 load, yes.
3 MS. DENISE PAMBRUN: Right. And the
4 fact that we've created a class is a decision that
5 this Board has chosen to make after a whole bunch of
6 argument about whether and how it should be done.
7 Isn't that right?
8 MR. PATRICK BOWMAN: Yes.
9 MS. DENISE PAMBRUN: Right. So
10 despite the fact that in principle, there isn't a
11 great deal of difference between that pole attachment
12 fee and the revenue it generates, the fact that it's
13 netted out after costs, and it's included in the Cost
14 of Service Study, it's not really very different in
15 principle from the concept of net export revenue.
16 Isn't that right?
17 MR. PATRICK BOWMAN: Well, it's only -
18 - the only difference is, I think, if you went to look
19 at, you know, late -- late payment fees, Hydro doesn't
20 in -- incur a cost under a business case in order to
21 generate more net -- late payments fees.
22 It -- I -- I don't think it incurs any
23 material costs to be able to allow Shaw or MTS to
24 connect the wires to their poles. I might -- may -- I
25 may be wrong about that, but the utilities I've dealt

1 with don't incur any substantial costs associated with
2 that.
3 And exports is different, because it
4 clearly does drive some decisions in cost within
5 Hydro. But other than that, no, I'm -- I'm with you
6 all the way. This is -- and -- and that's the way
7 that exports were treated for years, actually, was
8 basically another revenue to be gained from the
9 system, so credit it back against the functions that
10 generate the revenue.
11 MS. DENISE PAMBRUN: Okay. Now, let's
12 turn to a different topic. At page 40 of your
13 report...
14
15 (BRIEF PAUSE)
16
17 MS. DENISE PAMBRUN: Okay. So page 40
18 of your report, this topic deals with the direct
19 assignment of DSM costs to participating classes.
20 We've already heard a little bit on that topic.
21 You're aware that the City takes the position that net
22 export revenue should be allocated to all costs minus
23 costs that have been directly allocated to the class.
24 Are you aware of that distinction, of
25 that -- the City's position with that distinction?

1 MR. PATRICK BOWMAN: I thought I was
2 aware of the City's position. And if I heard you
3 right, I think you just stated it the opposite way of
4 the way I understand it.
5 MS. DENISE PAMBRUN: And I think I --
6 I stated it very poorly. I'm sorry. You're aware
7 that 70 percent of the City's cost -- of the ARL
8 category costs are directly allocated costs?
9 MR. PATRICK BOWMAN: Right, the
10 fixtures --
11 MS. DENISE PAMBRUN: Okay.
12 MR. PATRICK BOWMAN: -- and things,
13 yes.
14 MS. DENISE PAMBRUN: And as a result,
15 net export revenue is not allocated to -- against 70
16 percent of the class is costs?
17 MR. PATRICK BOWMAN: Right. The City
18 has allocated 100 percent of the cost to those
19 fixtures and doesn't get net export revenue against
20 it.
21 MS. DENISE PAMBRUN: Correct.
22 MR. PATRICK BOWMAN: And -- and my
23 understanding is -- your position is that it ought to
24 be?
25 MS. DENISE PAMBRUN: It ought to be,

1 correct.

2 MR. PATRICK BOWMAN: Yeah.

3 MS. DENISE PAMBRUN: Now, you're

4 aware, and I'm not trying to put you on the spot, but

5 I -- I assume you're aware of that -- so you are

6 aware, then, when you talked about your view this

7 morning that at the end of the day, it wouldn't have -

8 - whether the DSM costs are allocated to generation

9 transmission distribution, or whether it's allocated

10 to the participating classes wouldn't have much of an

11 impact.

12 You're aware that's not true for the

13 ARL class because of that?

14 MR. PATRICK BOWMAN: Okay. We're

15 talking about -- about two (2) different things, but I

16 -- I agree with you in that the allocation of net

17 export revenue in the way City proposes versus the way

18 Hydro does it will have a major impact to the ARL

19 class.

20 MS. DENISE PAMBRUN: Okay.

21 MR. PATRICK BOWMAN: I -- I think the

22 -- the reference you were giving was to something

23 different, which is not about whether net export

24 revenue is assigned to --

25 MS. DENISE PAMBRUN: I'm sorry.

1 MR. PATRICK BOWMAN: -- DSM, but how
2 it's treated.
3 MS. DENISE PAMBRUN: But you -- you're
4 --
5 MR. PATRICK BOWMAN: But nonetheless,
6 I -- I accept that, yes, the City's position is
7 material.
8 MS. DENISE PAMBRUN: Okay, fair
9 enough. And you're also aware that the diesel class
10 has directly allocated costs of a hundred percent?
11 MR. PATRICK BOWMAN: Yes.
12 MS. DENISE PAMBRUN: All right.
13 MR. PATRICK BOWMAN: Yeah, diesel is
14 about $10 million or so, if I am looking at the sheet
15 right. Yeah.
16 MS. DENISE PAMBRUN: Okay. And the
17 allocated costs, the -- the costs that are directly
18 allocated to street -- to area and roadway lighting,
19 consists of streetlight standard posts, arms and
20 brackets, lamps and luminaires, poles. You're aware
21 of all of that?
22 MR. PATRICK BOWMAN: Yes.
23 MS. DENISE PAMBRUN: Okay. And if you
24 compare that to residential, there are a number of
25 items, such as line drops to residential properties.

1 And you're aware those are not directly allocated. Is
2 that -- is that my understanding? Is that correct?
3 MR. PATRICK BOWMAN: You know, that's
4 within the distribution system. And it's not a place
5 I spend a lot of time looking in -- in Manitoba's
6 case, so I -- I'm probably better --
7 MS. DENISE PAMBRUN: I'm not trying to
8 put you on the spot.
9 MR. PATRICK BOWMAN: -- not to
10 comment. Yeah.
11 MS. DENISE PAMBRUN: If you're not
12 aware, that's fine.
13 Now, if you recall from the last
14 workshop, Manitoba Hydro's rationale was that the
15 directly allocated costs were akin to fridges and
16 stoves. That is, they're sort of the end user point
17 and not really part of the overall Manitoba Hydro
18 electric system.
19 Do you recall that?
20 MR. PATRICK BOWMAN: Yes.
21 MS. DENISE PAMBRUN: Do you agree with
22 that rationale, as an expert?
23 MR. PATRICK BOWMAN: I -- I think
24 Hydro's rationale is sound. And I -- I won't get into
25 the fridges and stoves part, because again, that's

1 really into the distribution, but I'll give you an
2 example that -- that I do deal with in terms of -- of
3 our clients, and it's a -- a reality that they face.
4 Is that, when you have something like net export
5 revenue being allocated against -- against Hydro's
6 assets, anybody who uses those assets gets a -- a
7 benefit of some offset to their costs.
8 But something like a large industrial
9 power consumer will own their substation, their own --
10 it -- it'll -- the power will be delivered to them at
11 a high voltage, and they'll take care of doing all of
12 the -- the substation transformation costs on their
13 own.
14 And to the extent that, you know, Hydro
15 could have built that and charged them for it, or they
16 could have built it on their own and -- and paid for
17 it, and assuming that both sides could do it equally
18 efficiently, the costs shouldn't be materially
19 different.
20 If we got into export subsidy, if you
21 want to call, export -- net export revenue being
22 assigned against directly assigned assets, pretty
23 soon, these customers would be disadvantaged by the
24 fact that they built the substation themself rather
25 than just saying to Hydro, You -- you build it, you

1 pay for it, I'll write you a cheque, oh, and by the
2 way, can you throw some export dollars against it?
3 And -- and they would have got the benefit of those
4 export dollars.
5 So that -- that's where it sort of
6 arises in terms of the -- the -- looking at the large
7 customer class and -- but, I -- you know, without
8 getting into fridges and stoves, I think it's an --
9 it's an equiv -- quivalent conclusion that -- that the
10 end-use -- you know, pow -- power's delivered at the -
11 - as kilowatt hours. It's not delivered as -- as
12 lumens. It's not delivered as -- you know, as -- as
13 heat on a stove.
14 And -- and it's the customer's cost to
15 -- to transform it into their -- the -- the uses that
16 they're -- that they're going to make of it.
17 MS. DENISE PAMBRUN: Do you agree with
18 that even in the instance where some of the equipment
19 is shared?
20 MR. PATRICK BOWMAN: That's a bit -- I
21 -- I'd have to think of the example specifically, but
22 that -- that may give rise to a different conclusion
23 if the equipment is shared.
24 MS. DENISE PAMBRUN: Okay.
25 MR. PATRICK BOWMAN: Because I -- I

1 think if the equipment was shared, it wouldn't be
2 directly assigned. I think it would be probably in
3 the common assets. In which case, if you're going to
4 credit net export revenue back in the cost of service
5 study, you would probably credit net export revenue
6 against that.
7 MS. DENISE PAMBRUN: All right. And
8 then let's go back to my residential scenario. And I
9 appreciate you may know -- not know the actual fact,
10 but I'll ask you to make an assumption.
11 If you have a line drop that is not
12 shared that is solely for the use of a particular
13 dwelling, would you, with your rationale, make that a
14 directly allocated cost to that homeowner?
15 MR. PATRICK BOWMAN: Well, in cost of
16 service, we never really directly allocate customer-
17 by-customer costs. We allocate to a class. And so
18 you -- your question is: Do you have to break out the
19 residential service drops versus the -- the general
20 service service drops or -- or can you -- can you just
21 have a service drops category they're both sharing?
22 In my experience, you would do it
23 commonly in a -- in a way that -- that all of the
24 classes share in, and you make sure that you're not
25 disproportionately disadvantaging some customers

1 against others by having a consistent system extension
2 policy.
3 So you won't have one residential
4 consumer who has a 20-foot service drop and another
5 one that has a -- a 20-mile service drop. If the
6 person has a 20-mile one, they have to pay for that
7 asset. You have a certain consistent set of policies
8 to make sure that you have the -- the costs of those
9 shared fairly across all those customers.
10 But again, it's -- when we get into the
11 distribution system, I -- you know, it -- I don't know
12 -- I -- I've never seen Hydro specifically allocate
13 residential service drops versus general service small
14 service drops. But if they did, it would be outside
15 the norm of what I've dealt with.
16 MS. DENISE PAMBRUN: Thank you.
17 That's helpful. Can you turn to page 18, then.
18
19 (BRIEF PAUSE)
20
21 MR. PATRICK BOWMAN: Yes.
22 MS. DENISE PAMBRUN: Pages -- no,
23 sorry, lines -- I'm sorry, you have -- you have four
24 (4) items there, one (1), two (2), three (3), four
25 (4)?

1 MR. PATRICK BOWMAN: Yes.

2 MS. DENISE PAMBRUN: Line -- item

3 number 3, if there is no participating class for a

4 particular classified cost, then I'm just -- I just

5 want to make sure I understand this. Then I take it

6 that number 4 would automatically not be in play.

7 That is, it would be automatic that there would be an

8 embedding.

9 Is that right?

10 MR. PATRICK BOWMAN: Well, no. This

11 is -- this is the section that's dealing with those

12 costs which are going to be spread across more than

13 one (1) customer class. Section 4, we deal with costs

14 that are specifically assigned to a given customer

15 class.

16 So this is -- these are allocated

17 costs, meaning they're going to be shared in some way.

18 And steps 1, 2, and 3 are the common ones. Four (4)

19 is where you add that you have to identify which

20 classes will share in it. I -- I don't think you

21 could end up with zero there, and if you were to end

22 up with a one (1), it would be -- it would be

23 specifically assigned.

24 MS. DENISE PAMBRUN: So the third item

25 doesn't automatically embed consideration of your

1 participating classes?

2 MR. PATRICK BOWMAN: No, not

3 necessarily. It's -- it's a question of -- you know,

4 for example, if your cost is classified to energy, the

5 third step is, What type of energy? You know, is it

6 winter energy, summer energy, weighted energy? That's

7 -- that's really what that third class is doing --

8 third step is doing.

9 MS. DENISE PAMBRUN: Okay. Right.

10 Now, page 21.

11 MR. PATRICK BOWMAN: M-hm.

12 MS. DENISE PAMBRUN: So I think,

13 despite the many problems associated with the term

14 "cost causality," we agree that it is the fundamental

15 principle associated with cost studies.

16 Is that correct?

17 MR. PATRICK BOWMAN: Yes.

18 MS. DENISE PAMBRUN: And my

19 understanding is that you believe there should be a

20 split between energy and demand.

21 Is that correct?

22 MR. PATRICK BOWMAN: Yes.

23 MS. DENISE PAMBRUN: All right. And

24 it's also your position that energy is worth a

25 different amount depending on the time in which it is

1 used.

2 Is that correct?

3 MR. PATRICK BOWMAN: Yes.

4 MS. DENISE PAMBRUN: Okay. But you'd

5 agree with me that when a particular asset is built,

6 the costs that were incurred when it was built remain

7 the same no matter when the energy it produces is

8 consumed.

9 Is that correct?

10 MR. PATRICK BOWMAN: Well, generally,

11 yes. Your -- your interest cost will change as an --

12 as its rate-based value goes down or something. But

13 generally, yeah, it's -- you fix the cost.

14 MS. DENISE PAMBRUN: Right. So when

15 it comes to generation, if you focus too much on

16 demand, what you're essentially doing is moving away

17 from causal -- cost as the causative factor and moving

18 towards price as the driving factor.

19 Isn't that right?

20 MR. PATRICK BOWMAN: I -- I don't

21 follow the question. By "demand," I think we have to

22 make sure we're talking about the same thing, "demand"

23 meaning some feature of the generator that can help

24 supply a peak output for short -- or short periods. I

25 don't know where -- where price fit into that.

1 MS. DENISE PAMBRUN: Well, you're talk
2 -- we -- you've -- you've introduced the principle of
3 energy costs something different depending on what
4 time it is consumed. And so that is all about the
5 price, the market value.
6 MR. PATRICK BOWMAN: Well --
7 MS. DENISE PAMBRUN: So you're
8 bringing that into the driving factor of cost, and
9 cost is supposed to be about what it cost.
10 MR. PATRICK BOWMAN: No, I think
11 energy -- energy has a different importance to the
12 system, depending on when it's consumed. As a result
13 you would think about the -- the cost of supplying
14 energy at different periods being different. And in
15 this case, as I said in -- in a direct and appropriate
16 way, we look to the SEP prices to give us an idea of
17 that -- that balance across different periods. It's
18 not to say that -- that you're looking to bill the
19 price in.
20 The purpose of the cost of service
21 study is to -- is to drive the price, not to -- not to
22 input the price.
23 MS. DENISE PAMBRUN: All right. Now,
24 your opinion is that the weighted energy approach does
25 not reflect demand explicitly but only implicitly, and

1 therefore does not properly capture capacity
2 causality. Is that right?
3 MR. PATRICK BOWMAN: Well, it -- it
4 doesn't even really do it implicitly because it's so
5 coarse. You know, demand is -- energy and demand are
6 two (2) sides of the same coin. Demand, we will often
7 talk about the -- the average over the course of an
8 hour. Energy is just demand averaged over eight
9 thousand seven hundred and sixty (8,760) hours.
10 The -- the method that Hydro uses for
11 weighted average takes the -- uses energy in -- in
12 twelve (12) time periods which they -- they vary but
13 they're around six (6) or seven hundred (700) hours.
14 So it's just taking what is a short-term price signal
15 and overly averaging it in -- into these -- these
16 large time periods.
17 And suggesting that it's a -- it's a
18 component of -- of what's in there, sure it is, but
19 it's so averaged across so many hours that -- that the
20 signal is -- is muted to -- to -- beyond recognition.
21 MS. DENISE PAMBRUN: So as a result,
22 you suggest there needs to be a cost of service
23 allocation by a -- what you call a properly
24 constructed demand classification, and coincident peak
25 allocation for a percentage of generation costs.

1 That's what you're proposing, right?

2 MR. PATRICK BOWMAN: Yes.

3 MS. DENISE PAMBRUN: Okay. And if

4 that's done, shouldn't you be eliminating the weighted

5 energy approach to allocate the energy component?

6 MR. PATRICK BOWMAN: No.

7 MS. DENISE PAMBRUN: Well, you're

8 double dipping, aren't you?

9 MR. PATRICK BOWMAN: No, because I

10 don't accept that the weighted energy approach is in

11 any way picking up a capacity price signal that isn't

12 muted beyond recognition -- isn't averaged out in over

13 so many hours and so much time that the -- even if

14 there were a capacity price in it -- and Mr. Harper

15 and I went over this this morning.

16 Even if there were a capacity price in

17 it, (a) it's not a capacity price linked to Hydro's

18 system which is where capacity really matters. When

19 you're talking about capacity, you're talking about

20 reliability. You're talking about investment. You're

21 not talking about what I could buy a bit of kilowatt

22 peak from the market for.

23 (b) you're using an SEP price which is

24 very short term, and will -- it's -- it's debatable

25 but it's unlikely it includes the type of -- of

capacity components that -- that one would consider to be fully loaded, and Christensen raises the same issue. And -- and (c) is you then take that price and average it across so many hours that you completely lose any -- any sense of -- of a peak responsibility.

So, no, I don't -- I don't think that they're double counting at all.

THE FACILITATOR: Denise, the time is up. Do you have one (1) final question? I see John seems to be wanting to get one (1) in.

MR. JOHN TODD: Yes. My job is to explain things to Denise, including what other parties are saying, and I need help to explain this one (1) to her, Patrick.

THE FACILITATOR: How about in one (1) question, John?

CROSS-EXAMINATION BY MR. JOHN TODD:

MR. JOHN TODD: Sure, Bill. A PCOSS is a fully allocated embedded cost study. The SEP prices are completely unrelated to any embedded costs.

If we were to use an energy allocator, would it not be more appropriate to use an energy allocator that reflects the variable costs incurred by hour if we're talking about -- having separated out

1 demand, we're talking about just the energy -- just an
2 energy weighting?
3 MR. PATRICK BOWMAN: So you mean an
4 unweighted energy --
5 MR. JOHN TODD: Well, it would
6 virtually be an unweighted because the variable costs
7 are so small. But if you're going to weight it,
8 shouldn't you be weighting it by embedded costs which
9 would for energy be the variable costs, which would be
10 fuel costs, water rental, and so on?
11 MR. PATRICK BOWMAN: Well...
12 MR. JOHN TODD: Why is SEP relevant in
13 an embedded cost study?
14 MR. PATRICK BOWMAN: Well, it -- it's
15 a really good question. And it's something that a lot
16 of us have wrestled with, more so a decade ago when it
17 first came forward than recently, but the question is
18 why are you -- even if you go to it, why -- why are
19 export prices being brought into talk about domestic
20 costs? Haven't we just like mixed and matched beyond
21 all recognition?
22 And there was a fair bit of -- of
23 debate about this for sure in '06, I think even before
24 that. And it was a -- it's -- it -- it was an unusual
25 proposal when Hydro brought it forward.

1 It originally was unworkable because
2 they were trying to use long-term marginal costs that
3 noone could test. We've eventually settled on SEP
4 prices as a -- a proxy, a directional proxy. It's not
5 because short-term markets are your driving -- driving
6 factor in how the costs arise on your system.
7 But the -- the conclusion was that it's
8 a directionally appropriate signal by saying if you're
9 going to use energy or you're going to produce energy,
10 if you're a wind turbine or something, in periods that
11 -- that matter more, those kilowatt hours should
12 matter more.
13 If they're going to use them in periods
14 that matter less, those kilowatt hours should matter
15 less. And this is a way of -- of giving us a -- a
16 signal that -- that is directionally appropriate for
17 that -- for -- for that type of waiting.
18 It's not to say it's perfect. It's not
19 to say that the -- the SEP should be a -- over --
20 over-interpreted as to what its role is. It's -- it's
21 just a way of saying things like summer peak and
22 winter peak are way more important than something like
23 summer off-peak.
24 MR. JOHN TODD: Sorry, Bill, that's --
25 he's missed the point of my question, which is -- I'm

1 saying, not -- I'm not asking in the context of
2 Hydro's proposal. I'm talking about the question in
3 the context of your proposal, which is you've got a
4 demand and energy separated out.
5 So demand is addressed separately. So
6 this rat -- Hydro's rationale for reflecting demand in
7 the energy allocator is not relevant. Once you've
8 taken demand away, how can you justify having energy -
9 - weighted energy using SEP?
10 MR. PATRICK BOWMAN: Well --
11 MR. JOHN TODD: That's what I'm
12 missing.
13 MR. PATRICK BOWMAN: -- well, dem --
14 demand was never the rationale for Hydro using an SEP
15 weighting in the first place.
16 MR. JOHN TODD: Just answer the
17 question --
18 MR. PATRICK BOWMAN: And if -- and if
19 it were --
20 MR. JOHN TODD: Once it's split --
21 once it's split --
22 MR. PATRICK BOWMAN: Once it's --
23 MR. JOHN TODD: -- once the -- once
24 you've split demand and energy --
25 MR. PATRICK BOWMAN: Right.

1 MR. JOHN TODD: -- what's the
2 rationale for keeping the SEP price as a weighting for
3 energy onl -- for the energy portion?
4 MR. PATRICK BOWMAN: Because all we've
5 done by taking out demand is given a little bit of a -
6 - little meaning 15/20 percent of the cost of a -- a -
7 - of a super weighting to a peak of fifty (50) hours.
8 Having done that, we still haven't
9 captured the fact that summer daytime use is -- should
10 be weighted higher than summer nighttime use and --
11 and winter daytime use outside of peak hours -- but --
12 or out in peak hours, but outside of the super peaks
13 should be weighted heavier than -- than fall off peak,
14 because those are -- because it's not just about every
15 kilowatt hour is equal.
16 Every kilowatt hour still have
17 different considerations on Hydro's system. It's the
18 same system that Hydro would -- would, like I say, pay
19 different amounts for wind with different profiles.
20 It's not because of the capacity. It's because of the
21 -- the energy product having different value in
22 different periods.
23 MR. JOHN TODD: Okay. Thank you for
24 your indulgence, Bill. I still can't explain this to
25 Denise, but at least we've got Patrick's answer.

1 THE FACILITATOR: Thank you. And even
2 though Denise is a -- a lawyer, it was good of the two
3 (2) of you not to put the button on her anyways for
4 the 4,000 volts. All right. Manitoba Hydro, oh boy.
5 Okay.
6
7 (BRIEF PAUSE)
8
9 THE FACILITATOR: Karen (sic),
10 retribution being the first law of mankind, this is
11 your opportunity.
12 MS. KELLY DERKSEN: Thank you.
13
14 (BRIEF PAUSE)
15
16 CROSS-EXAMINATION BY MS. KELLY DERKSEN:
17 MS. KELLY DERKSEN: Good afternoon,
18 Mr. Bowman. I'm going to walk through your evidence
19 with you with the intent really of clarifying certain
20 aspects of that evidence so that we have a full
21 understanding of what it is that you're recommending.
22 I'm sure you're not surprised at all,
23 or other parties are not surprised at all to know that
24 we have prepared a -- a matrix, if you will, of
25 positions advanced by various parties and where

1 parties are, I won't say in agreement, but maybe at
2 least directionally consistent, and where, you know,
3 the -- the major issues of contention lie.
4 And it might come as a surprise to
5 many, that at least at the conceptual level, there --
6 there's a fair amount of agreement. And so part of
7 what I want to ask you, Mr. Bowman, is to confirm that
8 interpretation of -- of our reading of the evidence.
9 You identify, at length actually, a
10 number of -- a number of tests to be applied in part
11 as you called -- I think your words this morning were
12 "to put the meat on the bones" with respect to how you
13 view cost causation.
14 It may go beyond that, I'm sure you'll
15 explain, and I really had to dummy this down for
16 myself so that I could understand all the tests that
17 you have advanced in your evidence. And so I've done
18 that.
19 And so there are three (4) or four (4)
20 tests that you apply in terms of your economic
21 identity. Number 1, planned for, not used for; used
22 for, not planned for; neither planned for nor used
23 for; and a fourth is What is the alternative that
24 could have been place -- put in place in lieu of the
25 asset chosen?

1 Other tests are utility industry
2 practice, perhaps with the exception of FERC rules;
3 the "but for" test; the "but for" test but only to the
4 extent if there are other network features or multiple
5 roles for transmission -- I think the "but for" test
6 is the test that you apply to distinction to be drawn
7 between generation and transmission; regulatory
8 precedent, at least sometimes; and the dollar value of
9 an asset, how material a particular asset is.
10 I'm not sure. I may have missed some,
11 and you can identify if I have. But my question to
12 you is: Can you help me understand or can you tell me
13 what test that you should use to determine what test
14 that you use?
15 In other words, how does one place
16 priority, or what is your ranking of these tests in
17 terms of influence in cost of service, please?
18 MR. PATRICK BOWMAN: Well, I guess my
19 first comment would be the -- the first few things
20 that you referenced were the -- the bullets that were
21 only meant to help explain why cost causation is not
22 sufficiently descriptive to always get you through.
23 And that was the planned for, not used
24 for, or used for, not planned for. Those were
25 examples of why neither planned for nor used for can

1 be the absolute limit of deciding. Now we're at page
2 13 to 14. They weren't really the -- the sequence of
3 tests.
4 The sequence of tests were the ones I
5 went through this morning with Mr. Harper, and I
6 hadn't necessarily designed them as a sequence, but
7 they seem to work as that, which is fine, the -- the
8 first being, you know, Why do you bother to continue
9 to incur the cost of an asset, keep it on your system?
10 A second that can be informative is:
11 What was a -- what was the original basis for the
12 cost? What was the original investment?
13 A third that can be relevant but you
14 have to be careful with is: What is the asset -- you
15 know, how is it used in the system? And you have --
16 have to think, in Manitoba Hydro's system, about used
17 under which conditions and which waterflows.
18 Those are the sort of three (3) major
19 steps. I think they all are informed by -- and I was
20 trying to write this down on the fly -- by the fact
21 that you wouldn't bother to apply it to costs that are
22 de minimis. So the dollar value is relevant.
23 Also that the -- I think the regulatory
24 precedent is not over -- overwhelming, but it is a
25 consideration that if -- if -- and it's not to say

1 that precedent is binding.

2 It's to say that, if people have spent

3 the time and the money to debate an issue over a

4 twenty (20) day hearing and come to a conclusion, you

5 probably should put some weight on the fact that --

6 that that was -- that the people at the time knew what

7 they were talking about, or -- or hopefully knew what

8 they were talking about, and you don't throw that out

9 easily. It doesn't mean you don't throw it out at

10 times.

11 But -- and also the other utilities'

12 practice I think can be informative, but I didn't -- I

13 didn't necessarily put it as a test. I don't

14 automatically you would say, I should do it this way

15 because -- because Maine does it this way.

16 But I think if you're saying I've come

17 up with a method that is entirely inconsistent with

18 everyone else in the utility industry, your -- your

19 hurdle of -- of evidence needs to be a little bit

20 higher.

21 So why do you both to continue to

22 invest and -- and incur the cost when -- if there is

23 no basis for the investment, and -- and them sometimes

24 also what is it used for are the big three (3).

25 MS. KELLY DERKSEN: Thank you for

1 that. I'm going to turn to -- on the topic of Bipole
2 III.
3
4 (BRIEF PAUSE)
5
6 MS. KELLY DERKSEN: Can you confirm
7 for me, I'm not sure that I heard in your evidence
8 this morning -- certainly if -- if you said it I
9 missed it so I apologize, and I -- and I didn't find
10 it in your written evidence either but can you
11 confirm to me, Mr. Bowman, that your evidence is that
12 Bipole III is transmission reliability versus
13 generation reliability?
14 MR. PATRICK BOWMAN: Well, Bipole III
15 is a transmission asset. It doesn't produce power.
16 It moves power. So from that sense it's -- it's --
17 would -- would normally be considered to be
18 transmission. So I don't know if that -- that answers
19 the question about the way you're thinking about it,
20 or if I missed the question.
21 MS. KELLY DERKSEN: I -- I think what
22 you're saying is, yes, you -- you believe it's
23 transmission reliability. If I go through your
24 evidence, I'm not certain that you ever have inserted
25 the words 'transmission' in -- in advance of

1 reliability. So I wasn't certain although I
2 interpreted from the outcome of your evidence, which
3 is to functionalize Bipole III as transmission, that
4 therefore you would conclude that Bipole III is
5 transmission reliability, not generation reliability.
6 MR. PATRICK BOWMAN: Well, it's --
7 I've used the words reliability and I've used the word
8 transmission. When you put them together they start
9 to mean something a bit different. If you're dealing
10 with a planning context there are ways that people
11 think about -- about standards for generation
12 reliability and there are ways people think about
13 standards for -- for transmission reliability.
14 That serves certain purposes but at the
15 end of the day Bipole III is a -- is a transmission
16 solution to what Hydro identifies as a -- as a
17 transmission problem with -- with -- related to the
18 generation being up north and the -- the loads
19 primarily being down south.
20 MS. KELLY DERKSEN: Thank you. I
21 think the -- the answer was -- was, yes, I think.
22 MR. PATRICK BOWMAN: Well, I -- I just
23 want to -- you know, is it transmission reliability or
24 generation reliability? If there were a reliability
25 issue it could have been solved by transmission, it

1 could have been solved by generation. Hydro elected
2 to go transmission for -- for various reasons but
3 there -- there are equally -- solutions that could
4 have been used that were -- were generation or -- to -
5 - to solve it, and -- and there were people advocating
6 for those solutions as well.
7 MS. KELLY DERKSEN: Thank you. In
8 terms of the -- once we move into the operating
9 horizon, can you tell me what your view is on how
10 Bipole III will operate, please?
11 MR. PATRICK BOWMAN: My understanding
12 is that Bipole III will operate in -- in parallel with
13 Bipoles I and II. It -- it'll operate as part of the
14 overall -- of a overall HVDC system.
15 MS. KELLY DERKSEN: So to the extent
16 that Bipoles I and II, for example, would go down
17 Bipole III would absorb that -- that issue?
18 MR. PATRICK BOWMAN: That's my
19 understanding, yes.
20 MS. KELLY DERKSEN: Thank you. In
21 terms of your perspective regarding Bipole III, can
22 you provide some guidance to Manitoba Hydro in what
23 your view would be as to whether therefore if it's
24 transmission and it's reliability -- transmission
25 reliability, is it tariffable under the OATT, please?

1 MR. PATRICK BOWMAN: No, I can't -- I
2 can't provide you a conclusion on that. I would -- I
3 would think it's -- it's unlikely it's tariffable.
4 And if I was somebody using Hydro's transmission
5 tariff I would -- I -- I think that there would be a
6 strong argument that -- that I shouldn't be paying a
7 share towards it.
8 MS. KELLY DERKSEN: Notwithstanding
9 that it's a transmission reliability asset based on --
10 on your evidence that you view it not to be eligible
11 for tariff purposes under the OATT?
12 MR. PATRICK BOWMAN: Well, it's a
13 transmission asset that was built to address a
14 reliability problem. An alternative could have been -
15 - not that I was advocating it, but an alternative
16 could have been a generation investment to resolve the
17 same reliability problem.
18 Hydro even ran comparable scenarios
19 where they built natural gas generation or -- or ran
20 the scenario of natural gas generation down south.
21 Could have solved the same problem. Neither of them
22 would go in a transmission tariff.
23 So from a -- from an -- if I was
24 Saskatchewan trying to send power to Ontario, I don't
25 think I would be -- and all I want to do is -- is ship

power across some AC lines, I don't think in either case I would consider Bipole III or natural gas turbines located near Dorsey to be part of the essence of the transmission system.

MS. KELLY DERKSEN: Thank you. At -- if I can get you to turn to page 30 of your evidence, please.

(BRIEF PAUSE)

MR. PATRICK BOWMAN: Yes.

MS. KELLY DERKSEN: If I can make this paragraph more concise in this way, would you agree, please? Your conclusion that Bipole III, which has been operated -- which, in its absence, has been operated successively -- successfully in -- for decades without -- in the absence of that line, your conclusion is that Bipole III is not driven by generation.

Can you reconcile that to the last statement that you just provided me, which was the alternative to Bipole III was some other form of generation, please?

MR. PATRICK BOWMAN: I -- I'm not sure how the two (2) are -- are irreconcilable. You have a

1 load down south. You have generation up north. You
2 built Bipoles I and II to serve the generation up
3 north and deliver it to the load down south, not that
4 there was generation being wasted or an inability to -
5 - to move that power. The -- the system worked.
6 At some point, the load down south grew
7 to the point where there was concerns about
8 reliability. You could look at a number of different
9 ways to solve that reliability. It could be another
10 transmission line from the north to -- back up Bipoles
11 I and II. It -- it could be some generation in
12 southern Manitoba.
13 It -- La Capra even ran scenarios where
14 it was a transmission line to the south to -- to
15 import power to address that. Some utilities look at
16 other options, like signing up more interruptible
17 customers to deal with those situations. I don't
18 think it would have been suitable here. But it -- you
19 look at a -- a suite of options to deal with the --
20 the shortfalls and -- and you make a decision based on
21 the overall economics.
22 I don't -- I -- I don't think that's
23 inconsistent with the -- with the -- the statements
24 that -- at page 30.
25 MS. KELLY DERKSEN: Thank you for

1 that. Can I take you then to take -- to page 31 of
2 your evidence, please?
3
4 (BRIEF PAUSE)
5
6 MR. PATRICK BOWMAN: Yes.
7 MS. KELLY DERKSEN: And, in
8 particular, at 8 -- at lines 8 to 9 of your evidence,
9 you state:
10 "This deficit means that the
11 majority of hours in the winter peak
12 period as well as the winter
13 shoulder period may otherwise face
14 supply shortages or shortfalls in
15 the absence of Bipole III."
16 So when you use the word "supply,"
17 you're talking about energy or power from the
18 generators. Is that fair?
19 MR. PATRICK BOWMAN: Well, it's --
20 it's practical. That means delivered supply. But in
21 -- in practice, that's what a bulk power system does,
22 is it produces energy and it moves it to where it's
23 needed.
24
25 (BRIEF PAUSE)

1 MS. KELLY DERKSEN: At lines -- sorry,
2 excuse me. At page 26 of your evidence at line 7 and
3 secondarily at page 27, line 2, you conclude that the
4 FERC tests that are well accepted in the industry as a
5 result of lots of parties putting their heads together
6 to determine what should go in a transmission tariff
7 are poorly suited, do not appear to be determinative
8 nor fully appropriate.
9 And you abandoned those. You -- I -- I
10 believe your evidence is that you abandoned those, and
11 in -- in favour of the "but for" test. I was
12 wondering if you could help me, Mr. Bowman, understand
13 who in the industry uses the "but for" test, please,
14 because it's --
15 MR. PATRICK BOWMAN: Well --
16 MS. KELLY DERKSEN: -- new to me?
17 MR. PATRICK BOWMAN: -- in -- in the
18 interest of a -- a helpful workshop, the -- the test
19 you're referencing, which are actually in the
20 footnote, if you want to scroll down to the bottom of
21 page 26, are the tests that Manitoba Hydro used going
22 back as far as 2001 to conclude that Bipole I and II
23 should not be in the transmission tariff, but that the
24 Dorsey converter should be in the transmission tariff.
25 But you -- you can look at the quote

1 where it says:

2 "The Commission proposed seven (7)
3 indicators of local distribution to
4 be evaluated on a case by case
5 basis. Loc -- local distribution
6 fal -- facilities are in close
7 proximity to the retail customers.
8 Local distribution facilities are
9 primarily radial in character.
10 Power flows into local distribution
11 systems. If rarely -- if ever, it
12 flows out."

13 Those aren't generation versus
14 transmission tests. Those are -- those are framed as
15 distribution tests. Now, people apply some analogous
16 principles in looking at what should be in an open
17 access transmission tariff, but the -- and -- and
18 that's a -- that's a reasonable test.

19 Like I said, if I'm in Saskatchewan
20 shipping power to Ontario, it's reasonable to conclude
21 that Bipole I and II should not be part of the cost
22 that -- of the system that I'm using to -- to ship
23 power through Manitoba on the AC system.

24 But that's not what the Cost of Service
25 Study is doing. It's not trying to come up with rates

1 to apply to Saskatchewan shipping power to Ontario.
2 It's trying to come up with rates for domestic
3 customers. And when you get to dealing with domestic
4 customers, the idea is which transmission lines are as
5 -- as Mr. Grant quoted back to me, are effectively
6 driveways to the plant and not part of the highway
7 that service the area around the plant.
8 And -- and I can use the words "but
9 for." I -- I can't recall if I have seen those
10 before, but the -- this exact same test has been
11 applied in -- in coming up with 5 percent of -- of BC
12 Hydro's plant being assigned to -- to GRTAs and -- and
13 15 percent of Newfoundland's ending up being assigned
14 as -- as energy. It's -- the same principle is being
15 used in -- in all those jurisdictions that -- that
16 I've run across when you're dealing with generation-
17 related transmission.
18 And at least, I -- I -- but I -- I
19 think I have to claim ownership of the words. I don't
20 think I've seen them used in that frame -- in that --
21 that particular configuration before.
22 MS. KELLY DERKSEN: Thank you. And
23 I'd like to clarify at page 6 of your evidence,
24 please, where you provide a table.
25 MR. PATRICK BOWMAN: Yeah.

1 MS. KELLY DERKSEN: And I wasn't sure,
2 Mr. Bowman, if this was a typo, because it didn't -- I
3 couldn't find the discussion in the text and maybe I
4 missed it. But at page 6, under Bipole III, you offer
5 up three (3) solutions.
6 One (1) is winter CP, or 2CP. And the
7 second is marginal weighted -- sorry, marginal cost
8 weighted energy over the peak and shoulder winter
9 periods. Is that your proposal or is your
10 recommendation excluding the 2CP?
11 Can you -- can you help me?
12 MR. PATRICK BOWMAN: Yeah, I -- I
13 actually have 2CP circled with the word "typo" beside
14 it. So we both -- we -- we both got the same issue in
15 the evidence produced. That where it says, "or 2CP,"
16 it should be deleted.
17 The tran -- transmission demand, given
18 the nature of Bipole III, should either be based on a
19 winter CP, which is a normal type of -- of
20 transmission consideration for a winter peaking
21 system, or alternatively, given the hours that -- that
22 Bipole III is -- is now playing a role supporting over
23 the winter hours, a -- a winter energy spread across
24 the peak and -- and shoulder periods would -- would be
25 workable and -- and perhaps better capture that --

that it's not -- it's not one (1) hour that -- out -- type of outages that Bipole III will help avoid.

It's -- it's many hour outages over -- over a series of -- a long period of time throughout the winter.

MS. KELLY DERKSEN: Similarly, can you clarify -- and this may be more obvious, can you clarify that your proposal with respect to weighted energy for -- for Bipole is 100 percent energy using Manitoba Hydro's weighted energy allocator, but refined to constrain it to the winter peak and shoulder periods, please.

MR. PATRICK BOWMAN: Right, to focus on only those two (2) of the twelve (12) periods, yes.

MS. KELLY DERKSEN: But 100 percent energy, yes.

MR. PATRICK BOWMAN: Correct. Correct.

MS. KELLY DERKSEN: Thank you.

MR. PATRICK BOWMAN: Because you're -- you're now focusing on only about twelve hundred (1,200) hours or something, yeah.

(BRIEF PAUSE)

1 MS. KELLY DERKSEN: Can you confirm a
2 statement that you made this morning? I -- I don't
3 have the benefit of the -- the transcript, so I
4 apologize. I thought that I heard you say this
5 morning that, as load grows, and specifically related
6 to your proposed recommendation -- your proposal with
7 respect to Bipole III, that as load grows, you might
8 wish to refine the allocator that you've proposed here
9 to add more hours.
10 Did I hear that right, or did I
11 misunderstand that, please?
12 MR. PATRICK BOWMAN: Well, I think
13 it's -- as I said in the -- the hierarchy of -- of
14 tests, you should be applying the test to the -- the
15 facts. If the facts change, the -- the test should --
16 should reflect that.
17 And if your load pattern changed such
18 that Bipole III was providing significant reliability
19 benefits in -- in more hours of the year, then -- then
20 you should look at whether the -- the allocator is
21 still capturing that.
22 It was part of that overall first test.
23 Why -- why do you bother to continue to -- to have the
24 investment? If -- if load was to grow in a way that -
25 - that Bipole III was of -- of substantial reliability

1 value to domestic customers in -- in fall evenings
2 because some massive load came on the system in fall
3 evenings, then you'd want to look at that change in
4 facts and look at whether there should be an
5 allocation to -- to suit that.
6 MS. KELLY DERKSEN: Thank you.
7 Turning to Dorsey, if I can follow along with your --
8 your "but for" test at page 27 of your evidence, line
9 25 in particular, you conclude that the "but for" test
10 has to be fully satisfied in order to qualify an asset
11 as generation rather than transmission, and only if
12 there are no other network features or multiple roles
13 exist for that particular asset.
14 And I think your conclusion is that,
15 yes, Dorsey does meet your -- your "but for"
16 requirement, and -- because in the absence of -- of
17 Kettle and Limestone and Long Spruce, that Bipoles I
18 and II in particular would not exist. And you also
19 conclude that this "but for" test is a very practical
20 application of the principle. And that's at line 20
21 and 21 of -- of that evidence.
22 But then you go on to say, Well, yes,
23 it might pass the test, and, yes, it's a practical way
24 to look at it, but because of the other network
25 benefits that Dorsey provides -- let's say to the AC

1 network -- you conclude that Dorsey should continue to
2 be treated as -- as transmission.
3 And I'm trying to -- to rationalize how
4 one dismisses well-accepted industry FERC seven (7)
5 test factors and other tests that are applied in
6 favour of a "but for" test that's not recognized in
7 industry, but then ignore it in terms of your
8 treatment for -- for Dorsey.
9 Like what am -- what am I missing here?
10 Miss -- like if -- if the conclusion is:
11 "The 'but for' test is more
12 determinative, and therefore we
13 should be ignoring the seven (7)
14 factor tests, or other tests that
15 are prescribed by FERC on the basis
16 that they're more determine -- more
17 determinative."
18 Help me -- help me understand that. I
19 -- what am I missing, please?
20 MR. PATRICK BOWMAN: Well, I think
21 Hydro says it better than I ever could at the -- if we
22 go to the bottom of page 28 of -- of the document. I
23 have a quote from -- from the 2001 status updated
24 proceeding at the bottom of page 28 where -- and it's
25 the -- the quote that's there. It goes onto the next

1 page. And -- and it's -- it's not framed as a seven
2 (7) factor test but Hydro said:
3 "Without the flexibility and control
4 associated with a HVDC system,
5 Manitoba Hydro would have had to
6 make a much greater investment in
7 its ac transmission system to
8 provide the equivalent transfer
9 capability provided through the HVDC
10 system today. Hence, the Dorsey
11 converter station is concluded as
12 part of the transmission tariff
13 because its operation primarily
14 benefits all transmission customers
15 through the special features of the
16 HVDC system."
17 And that was the same time when this
18 seven (7) factor test was -- was listed there, and you
19 -- you can -- can go through it if you like with me
20 but I won't find any of those seven (7) tests that
21 conclude this -- that I can -- that I can see that
22 concludes this -- this outcome that -- that Hydro
23 recommended at the time, and that I still think holds
24 up as a rationale.
25 That the converter is -- was doing a

1 multiple -- multi function role. It -- it was -- was
2 -- it was built -- it was only built in that form
3 because of the northern generation but if it weren't
4 there in -- in that form that there would have had to
5 been significant other equipment, and -- which --
6 which would have no doubt been part of a -- of a
7 transmission tariff, and -- and an overall
8 transmission functionalization in the cost of service
9 study, so.
10 MS. KELLY DERKSEN: I'm sorry, I -- I
11 missed that last part of -- of your statement. You're
12 saying if HVDC didn't exist then nor would Dorsey, and
13 in its absence then we would have to build a more
14 robust ac transmission network? Is -- is that what
15 you've said?
16 MR. PATRICK BOWMAN: That's my
17 understanding of what the -- what the Manitoba Hydro
18 response said, and -- and it's -- it's the only
19 understanding I can -- I can derive that's consistent
20 with the conclusion that somebody shipping power form
21 Saskatchewan to Ontario should -- should pay a share
22 of -- of Dorsey converter. It -- it -- it's the only
23 one that makes sense in that -- in that regard.
24 MS. KELLY DERKSEN: Thank you. I'm --
25 I'm going to move on. I have a few other questions

1 that I'm going to abandon. It's taken a little bit
2 longer than I anticipated.
3 In terms of -- of net export revenue,
4 there was a fair amount of discussion this morning,
5 some of it which caused me a little bit of heartburn
6 quite frankly, but I just want to clarify -- and I
7 think you understand this, Mr. Bowman, but I want to
8 clarify that there's not this pot of money out there
9 called net export revenue that you can pull out and in
10 the absence of a rate change continue to support the
11 revenue requirement of -- of the Company.
12 So in other words, cost of service
13 deals with revenue requirement dollar for dollar, and
14 net export revenue in the context of cost of service
15 is really just this -- I hate to say this, this pokery
16 jiggery accountant kind of calculation that we do in
17 cost of service to determine the demarcation point at
18 which export revenues no longer have to be returned on
19 the basis of the assets that gave rise to it, in other
20 words generation and transmission, and it can be used
21 to return to customers in -- in different ways.
22 But in the absence of that net export
23 revenue, all else being equal, you would need to seek
24 a rate increase equal to the amount that you pulled
25 out. I -- I know that was really long-winded but

1 that's the crux of my question, please.

2 MR. PATRICK BOWMAN: Well, as a

3 preamble I say you've -- you've definitely won the fun

4 transcript word of the day contest. I've never gotten

5 pokery jiggery on the record before.

6 Yes, of course. And that's exactly

7 what Christensen said, and -- and I said in the --

8 Section 5 of -- of the submission. That once you've

9 concluded that -- that net export revenue doesn't

10 belong to be credited back to people.

11 In the cost of service study, you would

12 eliminate that column from the cost of service

13 analysis, and you would end up with the system's

14 overall cost coverage ration being something like 99

15 or 98 percent, meaning, given that this revenue's not

16 coming back, ratepayers -- domestic ratepayers are not

17 covering their costs.

18 And over time, you would work to bring

19 up those customer classes that are below a hundred

20 percent RCCs. You would have above average rate

21 increases to them as a result of that. You would free

22 up that amount that -- under the math in this -- in

23 this hearing is -- under the recommendations I've

24 made, it's around $50 million. That will change

25 heavily as Keeyask comes online and -- and as -- as

1 contracts change.

2 But you would free that up to say what

3 is the priority use for that, is it to -- is it to

4 credit back to customers so bills are a smidge lower

5 today for some customer classes, or -- or do we have

6 other priorities for -- for Hydro in terms of $50

7 million of costs that -- or $50 million of revenue

8 that -- that's not needed to -- to cover a full and

9 complete share of -- of what it costs to serve the

10 exports. And you'd move towards a system that -- that

11 thoughtfully considers that.

12 It is a revenue requirement issue

13 before it is a cost of service issue. But in the cost

14 analysis it's really easy to start by deleting that

15 column and just saying, overall, domestic customers,

16 once -- once exports have been credited to the fullest

17 extent that can be justified, have paid for their

18 share of the existing assets, domestic customers are

19 covering 99 percent of their costs, they're not at a

20 hundred.

21 All kinds of people run cost of service

22 studies that way.

23 MS. KELLY DERKSEN: Does your

24 perspective change if that amount is negative in terms

25 of whether you -- you put it out -- you -- you pull it

1 out of cost of service today and put it in a -- let's
2 call it an overdrawn rainy day -- rainy day account?
3 MR. PATRICK BOWMAN: Well, my -- no.
4 Part -- part of the reason why you'd come up with that
5 perspective is so that -- so that things like those --
6 those negative amounts are -- are taken out of your --
7 your cost calculations and -- and dealt with in a --
8 in some from of stabilization mechanism the same way
9 that -- that both Christensen and I reference.
10 I'm not going to say will be negative.
11 You know, you -- you -- if you -- if we stop putting
12 some of the -- the big allocations against exports
13 that -- that have no bearing on costs, like uniform
14 rates or -- or the like, if we stop trying to say
15 exports should pay for all of wind or pay for all of
16 DSM or some other policy-related thing, which are
17 items that the submission actually agrees with Hydro
18 on and are -- are big items, right now, like I said,
19 the net export revenue would be at $50 million already
20 today.
21 And I would think that there's reasons
22 to think that -- that might grow.
23 MS. KELLY DERKSEN: It's $50 million
24 if you choose to seek a rate increase equivalent to
25 $50 million which, in light of significant investment

1 in infrastructure that Manitoba Hydro is making today,
2 I'm not sure is a particularly wise financial decision
3 for it to do.
4 But, nevertheless, I think I got your
5 point, and that is you don't pull it out if it's
6 negative, but if it's positive, you pull it out. You
7 can either choose to explicitly put it in a reserve
8 fund. If you choose to do that you need a rate
9 increase that is based on the amount that you've
10 pulled out.
11 And so I -- I'm trying to understand
12 conceptually that if you leave export revenue in, net
13 export revenue in and it's negative, you're saying
14 today's customers should bear responsibility for the
15 costs that exports impose on the system.
16 But the converse is, if you pull out
17 the surplus, then future customers should benefit that
18 -- benefit from that. So I'm trying to rationalize
19 that disconnect in -- in my mind, that today's
20 customers would pay if it's negative, but future
21 customers should benefit if it's positive, and only if
22 it's positive?
23 MR. PATRICK BOWMAN: Well, then
24 perhaps I've misstated or you've mischaracterized what
25 I said. I didn't say you'd only do the adjustment if

1 it's positive. I said you would assign exports a
2 share of costs associated with their load consistent
3 with the other methods that we've discussed.
4 Those costs would not be assigned to
5 the -- the domestic ratepayers. That only the
6 remaining system costs would be assigned to the
7 domestic ratepayers. And you'd compare the domestic
8 system ratepayers' revenues to costs to determine if
9 they were fully covering their share of costs.
10 If exports is over covering its share
11 of costs, then you have room to do something to the
12 positive. If exports is under paying its share of
13 costs, then hopefully you've done what you needed to
14 have stabilization mechanisms to deal with that.
15 In either case, I -- I don't -- I don't
16 know why we start with this -- this premise that we're
17 -- we're seeking to balance or that we're putting
18 export shortfalls in as a -- as a cost, or export
19 surpluses in a cost. They're not -- they're --
20 they're not a part of measuring the costs to provide
21 service to -- to the shoe store.
22 MS. KELLY DERKSEN: Okay. And so if
23 we accept that you just let cost of service be reduced
24 by the amount that ex -- net export revenue is, either
25 positive or negative -- I'm not quite certain what

1 that negative means -- but that cost of service is not
2 balanced and you let RCCs fall, let's say, which would
3 suggest you need to do one (1) of two (2) things:
4 either raise rates equal to that amount or you just
5 let cost of service fall and you say -- you accept the
6 -- the lower level of -- of RCCs.
7 And in the case of just letting RCCs
8 fall because you've pulled out this $50 million of net
9 export revenues, doesn't that effectively amount to an
10 allocation of net export revenue on the basis of 'G',
11 'T', and 'D'? And in this case, 'D' means including
12 direct-assigned costs also.
13 Isn't that the net effect, about --
14 about the same or very close to it, if you pull that
15 out?
16 MR. PATRICK BOWMAN: No. I think it's
17 actually the opposite. When you talk "pull it out,"
18 I'm not talking about pulling anything out. I'm
19 talking about analyzing costs and figuring out what
20 share of costs is export class and what share of costs
21 is domestic class, and then go look at the domestic
22 revenues and compare them to the domestic costs.
23 This would be a step after a revenue
24 requirement in a hearing. You'll already have
25 established the revenue requirements to ensure that --

1 that Hydro is -- is collecting overall what it needs
2 to collect and is -- is managing to keep the lights on
3 and the system is working.
4 And exports are making money or losing
5 money or they're doing whatever they're doing. But
6 our revenue requirement is keeping -- keeping Hydro
7 where the Board concludes it needs to be. This is
8 about relative level of people paying -- covering
9 their costs with their -- their revenues.
10 So once you -- all you're doing is
11 analysis of costs. This -- this is -- I had a comment
12 in the slides that I -- I skipped over, but Hydro's
13 excessive focus on -- on RCCs and on revenues and on -
14 - on balancing the Cost of Service Study is -- is
15 really unusual.
16 What we really need to focus on is:
17 What does it cost in cents per kilowatt hour to serve
18 a load? What it does it cost in dollars for kVA to
19 serve a load? What -- what does it end up costing
20 overall to serve a load? And how does that compare to
21 what people are paying at each of those unit costs?
22 That -- that's all it's about, and --
23 and there's no reason to have jiggery whatever it was
24 about some -- some revenue being readjusted. It's not
25 a -- it's not a revenue study. It's a -- it's a cost

1 of service.

2 MS. KELLY DERKSEN: Mr. Bowman, I

3 think that we would probably have to sit on a white

4 board, but the conclusion is -- is that, if you let

5 RCCs fall because you choose not to reflect net export

6 revenue in your Cost of Service Study because it's

7 unrelated to the costs, which is -- is your

8 conclusion, that it effectively amounts to allocating

9 that net export revenue on the basis of each class's

10 total revenue, which is very much similar or

11 equivalent to the assignment of net export revenue on

12 the basis of 'G', 'T', and 'D', including direct

13 assignments.

14 And so, you know, I started off my line

15 of questioning to say where I thought that we're not

16 that far apart from a conceptual perspective. And

17 that's what is driving some of my questions. And so

18 that's why I'm -- I'm asking that is that that's the

19 effect of doing that.

20 MR. PATRICK BOWMAN: Let -- me me just

21 --

22 MS. KELLY DERKSEN: I can --

23 THE FACILITATOR: Patrick, last

24 answer.

25 MR. PATRICK BOWMAN: Yeah, yeah. Just

1 to clarify two (2) things, just in case they were
2 lacking in clarity on the record. The first is that
3 I'm not suggesting I have magically found $50 million
4 that somehow someone can start doing something with.
5 That $50 million only arises to the
6 extent that, over time, you develop a principal Cost
7 of Service Study and you have it work its way to where
8 domestic ratepayers are paying 100 percent of domestic
9 costs, and hopefully each class is getting pretty darn
10 close to 100 percent.
11 And if exports are paying more than
12 their costs, you've got an extra $50 million. So that
13 -- that's the first piece. That is -- is, it's not
14 found money.
15 But the second is you -- you sort of
16 keep suggesting that somehow I've -- I've pulled a
17 math trick that takes that net export revenue and
18 subsidizes it to GNT versus GT&D.
19 And I'm saying, No, pull it -- don't
20 subsidize to any of them. Take the $50 million out.
21 Have -- have overall no -- no credit back through this
22 Cost of Service Study and work your way to no credit
23 back through your bills in any given year.
24 Have that be used for broader more
25 important long-term purposes. This -- this is the

1 kind of thing that -- I remember making a comment on
2 the record years ago that this doesn't make me the
3 most popular guy at the MIPUG meeting, but the -- if
4 overall ever class was closer to paying 100 percent of
5 their costs and exports were overpaying compared to
6 their costs and leading to $50 million being put aside
7 in something that helps ensure that future rates are
8 more stable, customers would be further ahead, because
9 they're not going to face a -- a surprise phone call
10 to the head office saying, Guess what, it stopped
11 raining, my bill's going up 20 percent.
12 MS. KELLY DERKSEN: Except today you
13 need a rate increase commensurate of what you pull out
14 in terms of net export revenue. If you need ten
15 dollars ($10) of revenue requirement today, cost of
16 service has to allocate ten dollars ($10). And if you
17 decide that two (2) of it is this fictitious NER that
18 we've calculated in cost of service and it can be
19 pulled out or it can be left in, if you pull it out
20 you need a rate increase of two dollars ($2), all else
21 equal.
22 I've got -- I've got your point though.
23 MR. PATRICK BOWMAN: Would it -- would
24 it suit an undertaking though, a table? You say
25 whiteboard, but I'm happy to do a table.

1 THE FACILITATOR: Well, perhaps later,
2 Patrick. I -- I think Reg had a question before --
3 MR. PATRICK BOWMAN: Okay, sir. Yeah.
4 THE FACILITATOR: -- we move on to
5 Daymark.
6 BOARD MEMBER GOSSELIN: I'm just
7 trying to understand -- understand that if there's a
8 positive net export revenue you are proposing it be
9 assigned to reserves. But if there's a -- if there's
10 a shortfall, I thought I heard you say you think rates
11 should be increased to cover the shortfall incurred by
12 export revenue?
13 So I just want to make -- make sure I
14 understand what you're -- what you've said. You had
15 clearly said if there's a net export revenue, a
16 positive net export revenue, that surplus would go to
17 reserves.
18 Now, if there's a negative export
19 revenue you, I think said, you should increase rates
20 of everybody else to cover that shortfall. Although -
21 - I -- I guess I want to clarify, because normally you
22 would think, Well, let's pull the money out of
23 reserves to cover their shortfall in exports.
24 MR. PATRICK BOWMAN: Well, let me go
25 back, sir, because I want to deal with what I said

1 separate from the -- the idea that you put up. So
2 just in terms of clarifying what I -- what I intended
3 to say and it's possible I misspoke, is that -- and --
4 and pull out ads to some of the issue here, because
5 we're -- we're focusing on a revenue item that most
6 times is not that critical to cost of service at all.
7 But one (1) -- I'm saying it wouldn't -
8 - you -- you would run a Cost of Service Study that
9 calculates the cost to serve each class and compares
10 them to a -- the -- the overall revenue requirement
11 for Hydro, which should already have been set.
12 And based on that you can get an idea
13 of where your rate adjustment should occur. You would
14 look at the revenue for each domestic class compared
15 to the cost information in the Cost of Service Study.
16 As part of that, if Hydro had 1.5
17 billion in -- in costs and exports are assigned 400
18 million of them you'd only be assigning 1.1 billion to
19 the remaining domestic class and you'd come up with
20 your numbers and you'd measure them. Now, all you've
21 done in that study is calculate that $400 million for
22 exports.
23 We know that that export revenue could
24 450 million, it could be 350 million, right. So our
25 exports might be overpaying, underpaying, whatever.

1 Right now, based on the methods they'd be overpaying
2 by about 50 million compared to the methods that I'm
3 suggesting.
4 And so if you actually got that Cost of
5 Service Study and you worked your way to the point
6 where that Cost of Service Study for the domestic
7 customers, everyone was fully covering their costs,
8 you would have all of Hydro's net income, which is
9 already in here as a cost, covered, and you would have
10 exports paying something over and above that.
11 And that over and above that would give
12 the flexibility to set up something specific for rate
13 purposes that -- that would allow you to work towards
14 more -- more stability. And the -- we -- we went
15 through this in some detail in past GRAs, but we're
16 not talking about just retained earnings. We're
17 talking about setting up some kind of mechanism, more
18 like a lot of other places have.
19 If that export went short you may end
20 up with a -- a negative item that could go against
21 those stabilization reserves if they've been --
22 already been built up. If they haven't built up you
23 have nowhere to charge it. But that export -- if
24 exports aren't covering your costs it's -- that
25 shortfall is also going to show up in Hydro's overall

1 revenue requirement.

2 They're going to be coming back here

3 asking for a rate increase anyway to try to get their

4 net income back to positive, or back up to levels they

5 need to be.

6 So in a way, it's always going to be

7 dealt with in that first step. If there's a revenue -

8 - or if there's a -- a export under coverage, you're

9 going to see those -- those rate increases coming

10 through either way. I -- I don't know if that -- that

11 explains it, but -- and as I said perhaps -- perhaps

12 an undertaking would -- would help, but -- but I -- I

13 don't think the magic arises in the cost of service

14 step.

15 In the cost of service step, you're

16 just trying to measure the cost. The magic, if it

17 exists, arises in -- in looking beyond -- beyond the -

18 - the mechanisms that Hydro has now for building up

19 reserves, and -- and looking if there's a -- a better

20 way to -- to structure some stabilization reserves.

21 But that -- that -- as I noted in the

22 evidence, that -- that's not even -- that's not even

23 part of the recommendations of this Cost of Service

24 Study. That would be something that people would deal

25 with when you finally got back to a -- a revenue

1 requirement hearing.

2 THE FACILITATOR: I wonder, though,

3 whether an undertaking wouldn't be good here, Patrick,

4 and with respect to -- and let me try it as an

5 undertaking, that the -- the focus of where people are

6 having trouble is -- is when the export -- the net

7 export revenue becomes negative.

8 MR. PATRICK BOWMAN: M-hm.

9 THE FACILITATOR: So we've allocated

10 the costs fairly to export revenue, and now the prices

11 are down and it's become negative. What are the

12 options for dealing with that either through the

13 revenue requirement or potentially through a draw down

14 of this -- this surplus account that you've had in

15 place?

16 MR. PATRICK BOWMAN: Sure, yeah --

17 THE FACILITATOR: Can you explain that

18 one in a -- in an undertaking?

19 MR. PATRICK BOWMAN: I -- I think I

20 can, yeah. I think we can do that.

21 THE FACILITATOR: Thank you.

22 MR. PATRICK BOWMAN: -- through an

23 undertaking.

24

25 --- UNDERTAKING NO. 32: MIPUG to explain what the

1 options are for dealing
2 with a negative net export
3 revenue either through the
4 revenue requirement or
5 through a draw down of the
6 surplus account
7
8 THE FACILITATOR: Kelly, I'm sorry for
9 getting your name wrong at the start.
10 MS. KELLY DERKSEN: I have a few more
11 questions, but you -- you tell me what -- if my time
12 is up or --
13 THE FACILITATOR: Well, the --
14 MS. KELLY DERKSEN: -- let me know.
15 THE FACILITATOR: -- yeah, the time is
16 over. Why don't we do this, because I'm not sure
17 whether Daymark has their full time, but let's try the
18 timeline with Daymark, and then any further questions
19 that the panel may have, and then return to you for
20 further questions if we finish -- well, like, let's
21 add a little bit of time here. Let's go till 3:15, so
22 if -- if we get through this before 3:15, then it's
23 yours, and if -- and if you finish, then it can be
24 Paul's if he still had questions. That --
25

1 (BRIEF PAUSE)

2

3 THE FACILITATOR: And --

4 MS. KELLY DERKSEN: I -- I'd

5 appreciate that. Thank you.

6 THE FACILITATOR: Great. Over to you,

7 John.

8

9 CROSS-EXAMINATION BY MR. JOHN ATHAS:

10 MR. JOHN ATHAS: Okay. Thank -- thank

11 you. Today, besides myself from Daymark, John Athas,

12 will be Brady Ryall will be asking some -- some

13 questions on behalf of the Board, as well. It might

14 not be necessary to go back to Kelly, because I might

15 be picking up on her questions after all.

16 So I -- I just wanted to go back to

17 where you were, Patrick, with the response to -- to

18 the Chair. If the -- if I have a revenue requirement

19 shortfall such that I -- of course, that isn't -- of

20 course, that's negative, that -- and the only thing I

21 need to do if I'm Manitoba Hydro in asking for my -- a

22 rate increase is ask for my -- a rate increase to

23 replenish retained earnings that have been diminished

24 below an acceptable level.

25 How would that -- how does that

1 retained earnings need to get replenished in a rate
2 increase get allocated amongst the classes?
3 MR. PATRICK BOWMAN: I -- I think I
4 have it, but it might be a lot clearer if you could
5 re-ask the question, just to make sure I've got it in
6 my head and I won't lead us all astray.
7 MR. JOHN ATHAS: Okay. If I'm -- if I
8 have had a shortfall because of the negative return --
9 net income -- net export revenues, and I've drawn down
10 my retained earnings, and I need -- and the only thing
11 that Manitoba Hydro needs a rate increase for is to
12 replenish the amount of the drawn down retained
13 earnings, how would that -- that retained earnings
14 refill, so to speak, as the rate increase would be --
15 get allocated amongst the classes?
16 MR. PATRICK BOWMAN: Well, I guess
17 first I would say if -- if you have an export market
18 price drop, as an example, is that an appropriate type
19 of example to use?
20 MR. JOHN ATHAS: It was just going to
21 be negative.
22 MR. PATRICK BOWMAN: Yeah, well the --
23 the -- you're saying that the -- the export class
24 would fail to cover its costs?
25 MR. JOHN ATHAS: Its allocated costs,

1 correct.

2 MR. PATRICK BOWMAN: Its allocated

3 costs. So -- so that -- that would arise, for

4 example, out of an export price drop, which -- as --

5 as an example, or -- or perhaps a new asset coming

6 online or something like that, Keeyask comes online,

7 but -- but mostly likely due to a shift in export

8 markets.

9 What you've got is not necessarily a

10 drop in Hydro's retained earnings. You've also got a

11 drop in Hydro's revenues going forward, so their net

12 income will continue to be lower, unless it's some

13 temporary bottoming out of export markets or the like.

14 And as a result, in either example,

15 whether it's because your retained earnings have

16 dropped, and so you need to work to build them back

17 up, or your -- your revenues have dropped, your export

18 revenues have dropped so that your net income has

19 dropped below acceptable level, the revenue

20 requirement step of this is always going to lead to

21 Hydro coming back for a rate increase. They're going

22 to have to come back for more to get back onto a

23 reasonable set of financial targets.

24 Does that -- does that much make sense?

25 Like, are we --

1 MR. JOHN ATHAS: That was -- that was
2 the base of my question, to get on a reasonable set of
3 financial indicators a la retained earnings.
4 MR. PATRICK BOWMAN: Right. And so if
5 you -- once you've done that, you have now compare --
6 compared to what it was without that rate increase,
7 you will have increased Hydro's net income. And that
8 net income -- like, without -- you -- you were saying
9 without the -- without the rate increase, their net
10 income would have been -- would -- would have been
11 lower?
12 MR. JOHN ATHAS: That -- that's right.
13 It would be -- there would be less retained earnings.
14 MR. PATRICK BOWMAN: There would be
15 less retained earnings. Well, less retained earnings,
16 but -- but less net income in that year, as well,
17 or...?
18 MR. JOHN ATHAS: Yes.
19 MR. PATRICK BOWMAN: Yes. Okay.
20 MR. JOHN ATHAS: That's how you get --
21 that's how you draw -- that's why you draw down on
22 retained earnings.
23 MR. PATRICK BOWMAN: That's what --
24 right. Okay. I'm just saying it wasn't like a one
25 (1) time thing, like, a one (1) time drought where you

1 come out of it and you say, My net income's the same,
2 but my retained earnings are -- are --
3 MR. JOHN ATHAS: I'm talking about --
4 we're talking about the -- doing, you know, successive
5 rate cre -- rate cases and doing the cost of service--
6 MR. PATRICK BOWMAN: Yeah.
7 MR. JOHN ATHAS: -- allocation that
8 comes up with that. And I just happened to have had a
9 draw down of a hundred million dollars of re -- of
10 retained earnings, because I had a hundred million
11 dollars in shortfall of net income and the -- and the
12 -- it all can be traced back to the -- to a shortfall
13 in export revenues?
14 MR. PATRICK BOWMAN: Right. So your
15 net income -- you need a rate increase to bring your
16 net income up.
17 MR. JOHN ATHAS: That's right.
18 MR. PATRICK BOWMAN: You go through
19 that step of your GRA and get your rate increase to
20 bring your net income up compared to what it would
21 have been without the rate increase. You come back to
22 the Cost of Service Study. And net income feeds into
23 the Cost of Service Study as -- as a cost of running
24 the system.
25 So you actually will have raised the

1 costs, including the costs allocated to all customers,
2 including domestic customers?
3 MR. JOHN ATHAS: Yeah, I'm -- I'm
4 trying to figure out when you goes -- when -- when
5 there is cost and recognizing a cost, how does it get
6 distributed between the classes as to how -- who
7 should -- how do they -- how does -- you determine
8 each class's allocation of the -- that need for money?
9 MR. PATRICK BOWMAN: If -- if Hydro's
10 revenue requirement includes a net income component,
11 which it usually does, that cost comes into the Cost
12 of Service Study, and it becomes part of the items
13 allocated in -- where on my schedule --
14 THE FACILITATOR: Sorry -- sorry,
15 Patrick, isn't -- isn't the answer a simple answer?
16 That they needed one (1) --
17 MR. PATRICK BOWMAN: Rate base.
18 THE FACILITATOR: -- they needed a 1
19 percent increase.
20 MR. JOHN ATHAS: That -- that -- no,
21 that's -- I -- I think he's got it.
22 THE FACILITATOR: Oh.
23 MR. JOHN ATHAS: He said my -- he said
24 the answer that I was expecting.
25 MR. PATRICK BOWMAN: Oh, okay. The --

1 I'm sorry, I -- I --

2 MR. JOHN ATHAS: He said it would be -

3 - it would be on total rate base.

4 MR. PATRICK BOWMAN: Well, it's

5 Schedule C9. It's a --

6 MR. JOHN ATHAS: Yeah, total --

7 MR. PATRICK BOWMAN: -- interest

8 expense and reserve contribution, yeah.

9 MR. JOHN ATHAS: Right. And total

10 rate base is -- is -- rate base is made up of capital

11 associated with generation, transmission,

12 distribution, and investments, whether they be

13 directly assigned or -- or allocated, correct?

14 MR. PATRICK BOWMAN: Sure. Yeah.

15 Okay, yeah.

16 MR. JOHN ATHAS: Okay. So without

17 having to worry about whether you agree or disagree, I

18 think I got the answer to Kelly's question.

19 MR. PATRICK BOWMAN: Well, I think

20 that the -- the piece that's missing --

21 MR. JOHN ATHAS: I'll now go -- now go

22 on with my question.

23 MR. PATRICK BOWMAN: Can I say the

24 piece that's missing is the net income you're talking

25 about? I'm not saying that you would -- that this

1 thing called taking it out and putting to reserves or
2 -- is necessarily going to be the same thing as net
3 income.
4 MR. JOHN ATHAS: You -- you answered
5 my question.
6 MR. PATRICK BOWMAN: Okay.
7 MR. JOHN ATHAS: Thank you. And so --
8 so -- but I -- I am going to go stay on the -- the net
9 export revenue topic. You -- you -- part of your
10 testimony went into a lot to describe the linkage
11 association between export revenues and certain
12 investments that the -- that Manitoba Hydro makes to -
13 - that -- that enable export sales to be made, like
14 generation.
15 And so let -- so -- and you -- and
16 that's why you allocate generation costs to the export
17 class.
18 Is that correct?
19 MR. PATRICK BOWMAN: Yes.
20 MR. JOHN ATHAS: Okay. So in -- in --
21 now looking at -- using the example of an economic
22 analysis of the -- economic analysis that was put
23 forward and accepted to some -- to a certain extent by
24 the Board on -- by -- related to Keeyask and the --
25 the NFAT.

1 That economic analysis was predicated
2 on having all the -- very -- many different scenarios,
3 but in each scenario, Keeyask created some additional
4 export revenues. And that economic analysis credited
5 that export revenue against the Keeyask costs.
6 Is that fair?
7 MR. PATRICK BOWMAN: Yes.
8 MR. JOHN ATHAS: Was it all of the
9 export revenues or -- or a part of the export
10 revenues?
11 MR. PATRICK BOWMAN: I -- I can't
12 think of where you'd be referencing only a part.
13 There's a --
14 MR. JOHN ATHAS: Okay. So it's all --
15 MR. PATRICK BOWMAN: -- a column
16 that's export revenues, and it's part of the economic
17 analysis --
18 MR. JOHN ATHAS: Right.
19 MR. PATRICK BOWMAN: -- and the
20 financial --
21 MR. JOHN ATHAS: Okay.
22 MR. PATRICK BOWMAN: -- analysis.
23 MR. JOHN ATHAS: That's great. I'm
24 just trying to take -- go by steps to make sure that
25 I'm -- that I haven't been missing something --

1 MR. PATRICK BOWMAN: Yeah. I just
2 don't want to trip on something minor. It's -- it's a
3 minor --
4 MR. JOHN ATHAS: So -- so the -- so
5 there -- there wasn't an identification of -- in that
6 economic analysis of net export revenues?
7 MR. PATRICK BOWMAN: Not cost of
8 service --
9 MR. JOHN ATHAS: No, no. Right.
10 MR. PATRICK BOWMAN: -- analysis, no,
11 no. No, so.
12 MR. JOHN ATHAS: But there was noth --
13 nothing like that to give someone -- outside of having
14 the water rentals, there was no money going to
15 someplace else?
16 MR. PATRICK BOWMAN: No.
17 MR. JOHN ATHAS: There was no money
18 being put away on a year-by-year basis to -- to
19 stabilization, there was no other --
20 MR. PATRICK BOWMAN: No.
21 MR. JOHN ATHAS: -- things like that.
22 It was --
23 MR. PATRICK BOWMAN: No.
24 MR. JOHN ATHAS: -- it was like if
25 you're going to make this investment, you would need -

1 - you take the export revenues and you use that to
2 offset the costs that are associated with Keeyask --
3 MR. PATRICK BOWMAN: Yes.
4 MR. JOHN ATHAS: -- in that analysis,
5 correct?
6 MR. PATRICK BOWMAN: Yes.
7 MR. JOHN ATHAS: Okay. So -- and that
8 -- that analysis doesn't differentiate the export
9 revenues into any kind of pieces that say, like, gross
10 export revenues and net export revenues? Okay.
11 MR. PATRICK BOWMAN: No. Not that I'm
12 aware of, no, no. Not -- and certainly nothing in net
13 the way we use the term in cost of service. Hydro
14 sometimes uses that term in a -- a different context,
15 but I -- I -- no.
16 MR. JOHN ATHAS: No, that -- that's --
17 MR. PATRICK BOWMAN: I -- that's
18 gross, I'm sure.
19 MR. JOHN ATHAS: -- that's helpful.
20 That's -- that's -- and, you know, since this is a
21 substitute for IRs, that's all -- all I think I need
22 on the record as opposed to a debate.
23 The -- so I'm going to turn over to --
24 turn it a little bit over to -- to generation-related
25 transmission assets. The -- if I interpret or can

1 summarize, one (1) component of the -- something that
2 helps that designation be justified in your mind is if
3 there was a kind of concurrent decision being made on
4 the asset of generation and that particular
5 transmission asset that -- that associates that
6 transmission asset with the justification of that
7 generation?
8 MR. PATRICK BOWMAN: Yes.
9 MR. JOHN ATHAS: Is that correct?
10 MR. PATRICK BOWMAN: Yes, absolutely,
11 yes.
12 MR. JOHN ATHAS: Okay. And -- and one
13 (1) of your concerns about Bipole III is that
14 obviously, there was no -- there was no generation
15 being justified at the time that Bipole III decision
16 was made?
17 MR. PATRICK BOWMAN: No, and -- and
18 vice versa, yeah, yeah.
19 MR. JOHN ATHAS: Now, in the -- but
20 you agree that Bipole I and II are generation outlet
21 type transmission?
22 MR. PATRICK BOWMAN: Oh, they were
23 absolutely included as part of the -- the complex
24 decision to proceed with the north, all that, yeah.
25 Though they -- they fit the -- the bill.

1 MR. JOHN ATHAS: Okay. So if I -- if
2 I had a -- if I -- if a great idea came out of the gen
3 -- the transmission planning department of Manitoba
4 Hydro of how to spend half a billion dollars to make
5 Bipole I and II indestructible to tornadoes, would
6 that be -- and there was no generation being
7 considered at that time, would that be an investment
8 that you would think is generation-related on
9 transmission?
10 MR. PATRICK BOWMAN: Well, it -- it
11 would become part of the assets that are there. So I
12 don't -- I don't think it would change the way you
13 classify those assets, or -- or, sorry, the way you
14 would functionalize those assets.
15 MR. JOHN ATHAS: Well, I might be
16 building a wall in front of it and over it. And it
17 still might not be touching the -- the assets that are
18 there. I'm not -- I'm not necessarily shoring up
19 poles and wires -- or towers and wires for
20 transmission.
21 But I'm just -- just -- I'm just
22 thinking about something that makes it better. Okay.
23 So you're saying so that -- you're -- you're saying
24 it's okay to call them generation-related because it's
25 -- you -- that -- that capital project that I'm

1 imagining here came out of -- is directly associated
2 with Bipole I and II?
3 MR. PATRICK BOWMAN: Well, I'd -- I'd
4 want to think on it a bit more but I don't see why you
5 -- if it was part of Bipole I and II, it -- yeah, it
6 could -- it could very easily end up as -- as --
7 MR. JOHN ATHAS: So --
8 MR. PATRICK BOWMAN: -- part of the
9 Bipole I and II. Now, what you do with it once you
10 get to classifying and allocating may be different,
11 but yeah.
12 MR. JOHN ATHAS: Okay. So when --
13 when Bipole III is -- is added to the system, and is
14 improving -- increasing the probability of being able
15 to deliver in certain circumstances on -- during the
16 winter peak period, what kind of events was that --
17 was that increase covering? Outages to Bipole I and
18 II?
19 MR. PATRICK BOWMAN: I -- I -- yeah,
20 primarily. I was just -- yeah, Bipole I and II is the
21 examples that are given in the -- in the -- the need
22 and alternatives submission, yeah.
23 MR. JOHN ATHAS: Okay. So can you
24 help me out with -- because I think the answer -- you
25 would -- then you would diff -- but you differentiate

1 Bipole III from the -- from this hypothetical capital
2 project that I was giving you in terms of whether they
3 should be generation-related transmission assets?
4 MR. PATRICK BOWMAN: Yes. Yeah, I --
5 I -- yeah --
6 MR. JOHN ATHAS: Help me out --
7 MR. PATRICK BOWMAN: -- at this -- at
8 this point I think I would. I'd -- I'd have to think
9 about the example you gave a little bit more, but at
10 this point, yeah, I think I'd --
11 MR. JOHN ATHAS: Is -- so what -- what
12 functionality -- and I know it's at this point,
13 because it's obviously I'm hitting -- this is, you
14 know, a -- a working session as opposed to, you know,
15 final brief testimony or anything like that.
16 So what functionality triggers in your
17 mind that's different about the way I've painted
18 Bipole III and the way I've painted the hypothetical
19 investment?
20 MR. PATRICK BOWMAN: Well, that's why
21 I said I need to think about it more in the context of
22 a working session. What -- you -- I'm not sure if
23 it's a -- if I -- if I can point to a functionality
24 aspect. I -- I think it's -- it's important to be
25 looking at the -- the considerations like, you know,

1 Bipole III is -- is generation related, and it's
2 whisked into that stream, it ends up being allocated
3 in a way that doesn't reflect the benefits that it
4 brings to the system. The -- the function that it
5 plays in the system.
6 I think one would have to think about
7 your other example the same way. I think you'd also
8 have to look at things like if Bipole III is
9 considered a -- a generation-related transmission,
10 we'll be at a point where Manitoba Hydro will be
11 considering 80 percent of its transmission investment
12 as -- as energy, or as generation related for a
13 classification that's more typically used for, like, 5
14 or 10 percent of transmission.
15 I think we'd have to look at that
16 example in terms of your -- your -- a model. It's not
17 just about functionality. It's -- it's whether we --
18 MR. JOHN ATHAS: It's past that --
19 MR. PATRICK BOWMAN: -- whether we --
20 whether we've driven --
21 MR. JOHN ATHAS: -- it's whether it
22 passes --
23 MR. PATRICK BOWMAN: -- a truck
24 through an exception, if you like, a -- a mod -- a
25 theoretical limited use category has all of a sudden

1 become -- it's the only thing we use. That -- I think
2 those are -- are relevant considerations, but I -- I'd
3 have to spend -- I think I -- I think in fairness, I'd
4 have to spend some time thinking about it.
5 MR. JOHN ATHAS: Okay. No, no. That
6 -- that's helpful. Okay. So and then -- so just to -
7 - just think about -- help think about it again,
8 because this is all helping me think about it. I
9 mean, I'm not -- I don't -- I don't have -- as I
10 mentioned when we were doing this with Manitoba Hydro
11 and Kelly was in the seat there, I'm asking questions
12 so I can understand how to potentially advise the
13 Board as opposed to having an answer.
14 So in -- in your driveway metaphor, and
15 I'm definitely a metaphor guy, we -- for -- for our
16 generation-related transmission, the way I kind of see
17 this, and tell me -- just to make it quicker, I see
18 the -- the metaphor working is the driveway leads to
19 the fire department.
20 And an emergency happens, and -- and
21 we're in like, winter peak, and we're -- and we're --
22 and we go to call the fire department, and we find out
23 that just when that emergency happens, there's a
24 couple of big trees over the -- over the two (2)
25 driveways that they have going out the front door.

1 And so the -- we get -- somebody says we've got to --
2 we've got to build something to make that -- to make
3 sure that they -- if that happens, we can get -- get
4 that fire department to be able to answer the call.
5 Do I build another driveway or do I
6 build more street?
7 MR. PATRICK BOWMAN: Or do you build
8 more?
9 MR. JOHN ATHAS: Street.
10
11 (BRIEF PAUSE)
12
13 MR. PATRICK BOWMAN: I'll tell you why
14 I -- I think it's -- I think this is where the -- the
15 driveway piece may be helpful in your kind of analogy,
16 that frankly, the more you have a Bipole III, or a
17 Bipole IV, or -- or other systems playing the role,
18 the less Bipole I and II will look like a driveway.
19 The more they look like part of an overall network
20 working together to deliver power, which is what
21 transmission is.
22 And I think that example goes to your -
23 - your fire department, too. The more that -- that
24 you put a bunch more driveways leading in, the more --
25 it's like a network and not -- not a specifically

1 dedicated driveway.

2 MR. JOHN ATHAS: If I build enough

3 driveways, is there no driveway?

4 MR. PATRICK BOWMAN: I guess it's just

5 a paved field then, but -- but generally, the -- the

6 idea is, you know, when people talk about it, the --

7 the -- generally from a later transmission, is the

8 wires that run from a generator to the first step up

9 station, right. That's -- that's the classic NARUC

10 definition.

11 We've already pushed it pretty darn far

12 by putting Bipoles I and II in there. I -- I've gone

13 with it. I think it's a reasonable -- but the more

14 you -- the more you make those look more and more like

15 a -- an overall network, the more that they're --

16 they're parallelled, and backed up, and different

17 routes you can send the power, and the -- the less it

18 looks like a driveway to me, is the -- it -- frankly.

19 It's -- it's not -- it's not like it

20 makes Bipole III all the more driveway. It makes --

21 if anything, it makes Bipole I and II all the less.

22 MR. JOHN ATHAS: But sometimes it's

23 really good to -- to not just rely on a generic thing

24 like a network and -- and to try to apply the logic

25 that they're using to -- to a specialty system like

1 Manitoba Hydro's.

2 MR. PATRICK BOWMAN: I -- I agree with

3 you. That's why I thought it was important to -- to

4 fill out something on the bones on the causes --

5 causation term.

6 MR. JOHN ATHAS: Okay.

7 MR. PATRICK BOWMAN: But -- but I

8 guess that -- that's the essence is, you know, you've

9 -- you've got these lines. Yeah, they're mostly about

10 bringing northern power, but some of that power can go

11 on the AC systems. Sometimes they -- you know, the --

12 the northern generation can still be used locally.

13 You're adding more lines so that they can -- you can

14 balance across multiple lines.

15 They're -- they're serving more of a

16 load-following role all the time. If anything, it

17 sure is -- it -- it's chipping away at the -- the

18 whole driveway nature of -- of Bipole I and II, I

19 think. But again, in -- in a workshop context, that's

20 just thinking on the spot. I'd want to...

21 MR. JOHN ATHAS: Yeah, I -- I kind of

22 think of -- "load following" is a word that -- a

23 phrase that usually gets applied to generation,

24 correct?

25 MR. PATRICK BOWMAN: Yeah, and it was

1 -- it was termed in -- in the -- the previous
2 workshop. The load following is done through Dorsey,
3 so.
4 MR. JOHN ATHAS: Okay. So turn --
5 turning to another topic then, just to -- to move off
6 of -- move off of the towers and wires for a moment,
7 I'm -- I'm trying to understand the -- as follow-up to
8 the questions about -- from -- from, I believe, it was
9 the -- the City of Winnipeg on the weighted energy and
10 the SEP use.
11 How does SEP affect revenue
12 requirements?
13 MR. PATRICK BOWMAN: Oh, almost not at
14 all. It's -- it's -- SEP generates some revenue from
15 the program.
16 MR. JOHN ATHAS: Okay. So how does --
17 so -- but SEP, you -- you said was a -- a proxy to get
18 -- so the -- the primary effect implemented that
19 kilowatt hours have different implications based on
20 their time of consumption?
21 MR. PATRICK BOWMAN: Yeah. Yes,
22 that's correct.
23 MR. JOHN ATHAS: Okay. So how does
24 kilo -- kilowatt hours being consumed at different
25 times affect revenue requirements? So, like, it --

1 let's just say that they -- it was kilowatt hours in
2 April versus July, both during the day.
3 MR. PATRICK BOWMAN: Those two (2) are
4 -- are less distinct than some of the others, but my
5 understanding is if you look to the -- the fundamental
6 measure Hydro was originally looking to -- to use,
7 which is more like a long run marginal cost, you could
8 look at adding an -- an increment to load in April,
9 adjusting your load forecast in that manner.
10 Running a SPLASH model and seeing the
11 total cost to supply the system versus your baseline,
12 and you could add a load to July, and run pea -- and
13 peak hours, and run the -- run the overall model to
14 see what it does to the -- the cost to supply the
15 system, and it would give you an idea about the
16 overall implications of adding that load.
17 MR. JOHN ATHAS: Okay.
18 MR. PATRICK BOWMAN: What is it
19 changing? It -- it depends on the water flow. It
20 depends on how the systems dispatch it in -- in
21 drought years. It might look different than flood
22 years in -- in times when you have opportunity
23 revenues that might look different than in times where
24 you're only have a dependable because you're in a
25 drought, for example.

1 MR. JOHN ATHAS: Okay, so does it --
2 but does it change the cost or does it change export
3 revenues?
4 MR. PATRICK BOWMAN: Well, that's what
5 Hydro's using as the definition of marginal cost for
6 the purposes of -- of every other investment it's
7 doing. Does it change your -- your embedded costs on
8 the system?
9 MR. JOHN ATHAS: I'm talking if you --
10 if you make a change in assumption when you go through
11 a test year calculation to get revenue requirements,
12 does the change in consumption from April to July
13 change the cost or does it change export revenues or
14 both?
15 MR. PATRICK BOWMAN: I think there are
16 situations where -- where it could change either. It
17 depends on those -- those water flow scenarios in
18 terms of how you use fuels versus purchases versus the
19 capacity you have available in your hydro plants.
20 It could -- it could be through either
21 of them changing, probably more revenues than -- than
22 costs. Hydro doesn't use that much fuel --
23 MR. JOHN ATHAS: So it would take --
24 take a seve -- it would take a non-median water year
25 to make it affect costs?

1 MR. PATRICK BOWMAN: It would take a
2 non-median water year --
3 MR. JOHN ATHAS: Well, we're doing
4 cost of service on a median water flow year to
5 determine, and the starting point that we have --
6 MR. PATRICK BOWMAN: Right. Well --
7 MR. JOHN ATHAS: -- to determine the
8 net revenue requirements that -- that Manitoba Hydro
9 needs to recover?
10 MR. PATRICK BOWMAN: Right.
11 MR. JOHN ATHAS: Okay, so -- so within
12 that context, if we -- if I suddenly ran in here said,
13 the load forecast was wrong, put stuff in April -- put
14 stuff in July instead of April, put some -- you know,
15 take some load out -- so I take some load out of July
16 and stick it in April, what -- what happens?
17 My -- my premise would be that export
18 revenues would go up if I freed up water to be sold in
19 -- in July?
20 MR. PATRICK BOWMAN: I -- I think in
21 the median water scenario that's probably true, yeah.
22 MR. JOHN ATHAS: Okay, so -- so the --
23 the way the time differentiation of the kilowatt hour
24 consumption manifests itself into a change in revenue
25 requirements is because it changes the prices of the

1 exports?

2 MR. PATRICK BOWMAN: It -- it changes

3 the -- yeah, the -- the price you're able to get for -

4 - for the exports. And you're only fo -- you're --

5 you're limiting this now just to the median water

6 condition, right?

7 MR. JOHN ATHAS: Which is the test

8 year for the cost of service study. That's right.

9 I'm focused very much on the cost of service study

10 because I'm not trying to -- I'm not trying to solve

11 the robustness problem of whether the revenue

12 requirements vary with -- with water flow.

13 MR. PATRICK BOWMAN: Well, okay,

14 except one (1) of the things that was emphasized is

15 that Hydro's cost of service study, despite the fact

16 that it's run on medium water, it's meant to be robust

17 across different water flows because it's going be the

18 same rates that area applied whether you're in one --

19 one type of water flow versus another.

20 And -- and, further, I think that's the

21 only meaningful way you could conclude that -- that

22 people want to talk about things like time of use

23 rates, is if there is a -- is if you're considering

24 all the implications on all the different water flows.

25 So I think the cost implications for

1 Hydro's system do need to be thought of in more than
2 just the median condition.
3 MR. JOHN ATHAS: And I -- and I guess
4 I -- since I don't know how domestic revenues --
5 domestic consumption would change with -- with water
6 flows, I don't know necessarily how you can manage
7 that robustness into the equation, so.
8 But -- but you just -- you helped me
9 out that the -- that right now, that under the median
10 flow conditions deterministically that we use for the
11 test year, that the way that the time of consumption
12 affects revenue requirements is on how it affects
13 export revenues.
14 MR. PATRICK BOWMAN: Yeah, I'm -- I'm
15 comparing that to something like the systems where
16 we’re -- do with non-interconnected. Like, I gave the
17 example of Newfoundland. If you use a kilowatt hour
18 in Newfoundland at midnight versus at noon, it doesn't
19 matter because you're going to use a drop of water.
20 And every time you use a drop of water there's one (1)
21 less in the reservoir. And as a result, somewhere
22 down the road someone will probably have to run a unit
23 of fuel.
24 So your -- your cost implications of
25 different time of day, season, time of year, outside

1 of capacity are completely indifferent. Every
2 kilowatt hour is on --
3 MR. JOHN ATHAS: Oh, yeah. I mean --
4 MR. PATRICK BOWMAN: It's almost
5 equivalent. Like, they're flat. But that's the cost
6 implications of -- of Hydro's system that we've heard
7 about year after year, that, you know, they -- the --
8 the shape of resources matter. The shape of loads
9 matter. Time of use is of interest. You know, those
10 -- those type of things are -- are relevant to this --
11 to this -- to the system.
12 MR. JOHN ATHAS: Right. And I -- I
13 was trying to understand the mechanics of how they
14 matter. This - I think you've -- you've helped me out
15 there, that if we --
16 MR. PATRICK BOWMAN: Okay.
17 MR. JOHN ATHAS: So that -- that's
18 fine. That's -- that's helpful.
19 Turning to my last -- or I have two (2)
20 more areas. The -- the allocation of -- of DSM costs
21 as direct assignment is -- is something that -- that
22 you are uncomfortable with because -- from a
23 theoretical standpoint or just an equity standpoint or
24 -- can -- can you just -- can you take me through the
25 -- your -- the principles you're relying on for DSM

1 allocation?

2 MR. PATRICK BOWMAN: Do you mean the -

3 - the --

4 MR. JOHN ATHAS: DSM cost allocation.

5 MR. PATRICK BOWMAN: Our -- our

6 perspective or my perspective on DSM is that I agree

7 with what Hydro has done to directly -- directly

8 assign it to the classes who participate. I think

9 that's a reasonable representation.

10 Is there -- if -- if that's -- if that

11 was the case, you would expect --

12 MR. JOHN ATHAS: Okay. So --

13 MR. PATRICK BOWMAN: -- you expect me

14 to say I can go into more detail, but --

15 MR. JOHN ATHAS: -- so now, the --

16 MR. PATRICK BOWMAN: Sounds like you

17 were going --

18 MR. JOHN ATHAS: -- so if -- if Hydro

19 is trying to decide what DSM programs to -- to

20 sponsor, and all the -- all the DSM programs are in

21 the residential class, and the reason why they're --

22 they're sponsoring those in the residential class is

23 because they have the lowest cost to them to -- per

24 kilowatt hour of procured -- and I'll just the old age

25 expression megawatts.

1 So they've got -- they've reduced the
2 domestic consumption in the residential class, and
3 they've -- and they've decided -- because those are
4 the programs that are most cost effective.
5 How does that -- how does that affect
6 the -- the large general service customers?
7 MR. PATRICK BOWMAN: Well, it does --
8 it -- it does a few things before you get to the Cost
9 of Service Study. First of all, Hydro will have
10 reduced its -- its load. It will have reduced its --
11 its revenue from the rest of the customers by whatever
12 that -- the units saved for.
13 MR. JOHN ATHAS: Okay. Yeah.
14 MR. PATRICK BOWMAN: So if you're
15 looking at an IFF, you're looking at a Revenue
16 Requirement Application, its revenues will be down.
17 Second, it will have freed up some
18 kilowatt hours that it will have been able to take to
19 market presumably. And it will have been able to go
20 get some export revenues for those -- for those
21 kilowatt hours. This is actually outside-the-province
22 dollars coming into the province. Benefit there of
23 whatever can earn in -- or in -- in export markets,
24 that will show up in an overall rate context.
25 MR. JOHN ATHAS: Okay.

1 MR. PATRICK BOWMAN: Okay. And the
2 third, in a -- in a revenue requirement, before you
3 get to cost to service, will that it'll have incurred
4 a cost to run the DSM program.
5 MR. JOHN ATHAS: Correct.
6 MR. PATRICK BOWMAN: And so that --
7 those -- those are the fundamental three (3) elements
8 in the -- in -- in any reasonable horizon for Manitoba
9 Hydro that will show up from a DSM activity, okay?
10 MR. JOHN ATHAS: I completely agree.
11 MR. PATRICK BOWMAN: Okay. So to put
12 some numbers on it, if you were to spend a penny,
13 reduce a kilowatt hour so that you lose seven (7)
14 cents in revenue and then sell that kilowatt hour on
15 the export market for say three (3) cents, you might
16 be -- have -- have overall revenues down by four (4)
17 cents overall, costs up by one (1) cent, okay?
18 MR. JOHN ATHAS: Okay.
19 MR. PATRICK BOWMAN: So you've --
20 overall, your -- your IFF has gone -- gone backwards a
21 small amount in -- in the -- in the short term and any
22 -- or in any reasonable horizon.
23 Now the question is: What do you do
24 when you get to the -- to the Cost of Service Study?
25 And the answer is that that seven (7) cents of reduced

1 revenue -- well, that's -- that's a revenue
2 consideration. That'll be in the eventual cal --
3 calculation of something like revenue cost coverage,
4 but it didn't change the costs overall.
5 The que -- your -- your export revenue
6 rises. Your export revenue gets allocated a share of
7 costs. Your class that reduced residential does not
8 get allocated that share of costs. Their cost
9 allocation goes down, and you're left with the
10 question: Who -- who pays this DSM?
11 MR. JOHN ATHAS: Okay. Well, so just
12 -- so -- so when the -- in the three (3) aspects that
13 you had there, I add costs to the revenue requirement
14 from the DSM programs.
15 MR. PATRICK BOWMAN: Right.
16 MR. JOHN ATHAS: And I subtract
17 revenue requirements for the export revenues, correct?
18 MR. PATRICK BOWMAN: Right.
19 MR. JOHN ATHAS: So I -- so I might
20 have lowered revenue requirements, okay, as in --
21 MR. PATRICK BOWMAN: Lowered revenue -
22 - you would be --
23 MR. JOHN ATHAS: -- low -- lowered
24 revenue requirements --
25 MR. PATRICK BOWMAN: Okay. Sorry.

1 MR. JOHN ATHAS: -- not --
2 MR. PATRICK BOWMAN: An increased rate
3 level's needed to --
4 MR. JOHN ATHAS: Right. That's the
5 next step. So then I have to -- but I have my -- I
6 load my sales -- I've loaded my sales so my -- my
7 ability to get that revenue from -- even that lower
8 revenue requirement from the current rates doesn't
9 work. I need to change my current rates.
10 So if I go through the allocation
11 process, would I -- I would probably then end up
12 increasing the allocation of cost to -- to the -- to
13 other classes other than residential because now they
14 have a bigger share of domestic cost allocation
15 parameters, whatever they are, whether they're energy,
16 load, demand.
17 MR. PATRICK BOWMAN: Your -- some --
18 some of your costs will be neutral. It'll just be the
19 kilowatt hour is -- is allocated to export versus
20 residential, depending on what -- how you allocate
21 cost to export. So if I'm a -- if I'm a large GS
22 customer and if the equivalent kilowatt hour used in
23 the equivalent hour, it -- that -- that cost may end
24 up charged to exports versus to residential.
25 MR. JOHN ATHAS: Okay. So that --

1 okay, that's right. So that -- the export goes up.
2 The other classes stay the same. Residential goes
3 down --
4 MR. PATRICK BOWMAN: That's right, you
5 --
6 MR. JOHN ATHAS: -- I allocate more --
7 I allocate more costs to -- to exports --
8 MR. PATRICK BOWMAN: Right, and --
9 MR. JOHN ATHAS: -- in the export
10 class.
11 MR. PATRICK BOWMAN: -- and that --
12 that's as long as opportunities are getting a share of
13 fixed costs, not -- not just the variable costs. And
14 that's only in the case where you're dealing with a
15 pie that is carved up to include exports because --
16 MR. JOHN ATHAS: Okay, that's fine.
17 MR. PATRICK BOWMAN: -- if you're
18 dealing with a pie that is not carved up --
19 MR. JOHN ATHAS: And that --
20 MR. PATRICK BOWMAN: -- to include
21 exports, the pie just got -- got less -- less -- or --
22 or each piece of the pie got bigger because it was
23 less units --
24 MR. JOHN ATHAS: Right. And so in --
25 in the framework that you're working with on the -- on

1 what you're supporting in your testimony, you end up -
2 - we end up allocating more cost to the export class
3 which may or may not have -- which -- which could --
4 which obviously will have some sort of effect on net
5 export revenues.
6 You know, that -- that combined
7 transaction of more export revenues because I freed up
8 the -- the water and made more export sales, but I've
9 also allocated some -- some cost to them. So the --
10 so the real question comes down to -- for the other
11 classes is what have I done -- what do I do with net
12 export revenues and -- because all I've done is move
13 the -- I've moved the share of -- a share of G&T costs
14 that used to go to residential I moved those to --
15 moved those to the export class, by and large.
16 MR. PATRICK BOWMAN: By and large.
17 MR. JOHN ATHAS: Okay. So that --
18 that's fine. That's -- that's all I need to go, okay,
19 for there. Now, the last one (1) that I have in the -
20 - is hopefully not that long, but is -- I really
21 wanted to just go and -- and then Brady has some quest
22 -- a couple questions, too.
23 The -- the interconnection in the -- in
24 the NFAT case there was interconnection expansion to
25 beef up with the addition of Keeyask, and -- which to

me sounds like it fits your -- it meets your criteria for interconnection being generation related.

MR. PATRICK BOWMAN: The interconnection from Keeyask to the -- the northern --

MR. JOHN ATHAS: The -- from the US to -- US to Manitoba system gets -- is increased as part of the ultimate case chose -- chosen as the plan to be approved by the -- by the Board, and one (1) of the plans put forward by -- by Manitoba Hydro. So the -- that makes the interconnection expansion an integral part of the decision as to what generation gets -- gets chosen.

MR. PATRICK BOWMAN: Well, if we -- if we hadn't driven a truck through the GRTA (phonetic) definition before by putting 80 percent of Hydro's costs in it, throwing the -- the US line into it, is -- I don't know, we're drive -- driving what's bigger than a truck through it.

MR. JOHN ATHAS: I'm not sure whether we're driving a truck through something or -- or over the logic of -- of cost justification connection as the GRTA kind of thing. So -- so that -- but it's similar but that's where you'd say that that's -- that's an extension of the -- of that application of logic that is stretched way too far, is what your

1 opinion would be.

2 MR. PATRICK BOWMAN: Oh, yeah. It --

3 because it's -- just because something is developed

4 contemporaneously because of the particulars of -- of

5 a business case doesn't mean they're necessarily going

6 to be a --

7 MR. JOHN ATHAS: Okay.

8 MR. PATRICK BOWMAN: -- a GRTA. It's

9 about a -- I don't know how the -- how the driveway to

10 Keeyask ends up going across the US border. That's

11 a...

12 MR. JOHN ATHAS: It's a big driveway.

13 But the -- so now -- now I guess the question is that,

14 well, forgetting that -- that classification is GRTA,

15 hasn't the -- the interconnection investment been

16 linked to making sales or exports or imports energy

17 transactions?

18 MR. PATRICK BOWMAN: It -- it's been

19 linked to cross border transactions of -- you know,

20 what else is there, exports or imports, yeah.

21 MR. JOHN ATHAS: Okay. And -- and the

22 -- and -- but those energy transactions and the -- the

23 genera -- the general transmission system is not

24 usually thought about for the -- you know,

25 specifically related to energy because you've kind of

1 got -- you've got those classified as, you know,
2 needing to cover demand, right? With the peak demand
3 is what your ma -- your major sponsorship of
4 allocation of the general trans -- the AC transmission
5 system costs?
6 MR. PATRICK BOWMAN: Tra --
7 transmission's almost universally demanded.
8 MR. JOHN ATHAS: Right.
9 MR. PATRICK BOWMAN: Is that what
10 you're asking?
11 MR. JOHN ATHAS: Yeah. And we're --
12 we clearly are talking about the almost, you know,
13 world. And that's what makes -- that's what makes it
14 so much fun playing with cost of service here in
15 Manitoba.
16 MR. PATRICK BOWMAN: Well, except it's
17 not almost. This one is an example where, you know,
18 if there's a -- if there's a transmission tariff
19 related to that line it's going to be on CP anyway,
20 just like -- we're -- we're -- you know, nonetheless,
21 that's -- yeah, it's -- it's almost universally
22 demand.
23 MR. JOHN ATHAS: Okay.
24 THE FACILITATOR: John?
25 MR. JOHN ATHAS: I'm finished with my

1 questions.

2 THE FACILITATOR: Thank you. Leaving

3 you with less than five (5) minutes.

4

5 CROSS-EXAMINATION BY MR. BRADY RYALL:

6 MR. BRADY RYALL: Okay. Well,

7 hopefully -- hopefully, in less than five (5) minutes

8 we can cover these. Good afternoon, Mr. Bowman.

9 There is two (2) things that was in the Board's pre-

10 hearing conference order that were issues that the

11 Board ruled to be in scope, and there -- there weren't

12 any -- you didn't address them in your evidence.

13 And I just wanted to canvass whether

14 that was because you didn't see them as an issue or

15 you just chose to focus on some -- on -- on more

16 pressing issues, and that is the -- I guess, the

17 relative composition of the different rate components

18 between a basic charge demand rate and a -- and a

19 energy charge. And for clients in particular, it

20 would just be a demand charge and the energy charge.

21 And I was wondering whether you had any

22 particular view of -- of whether those -- between the

23 demand charge and the energy charge, whether those

24 were -- you felt that those were appropriate the way

25 Manitoba Hydro has them for your clients at the moment

1 or was it something -- or is there something that you
2 feel needs to be addressed there?
3 MR. PATRICK BOWMAN: Well, just
4 splitting costs from rates, with respect rates, the --
5 Manitoba Hydro's already said it's going to bring back
6 a rate proposal, that it's going to include time of
7 use rates for industrials. And -- and for those
8 reasons, you know, talking about the rate structure
9 and the components was probably premature.
10 The -- the unit costs though is
11 something that was quite important. And I -- I assume
12 you haven't spent as much time with our appendices as
13 you might have liked. There's a fair bit in there
14 about the different methods that Hydro has used and
15 how much -- how changing the methods as they do will
16 often lead to someone saying, oh, this doesn't change
17 our RCC ratios very much.
18 But it actually bounces your unit costs
19 all over the place, which is usually a sign that
20 you've got a little too much activity in the -- in the
21 methods. And I -- this will go to page 56. We don't
22 have to go there. But nonetheless, there's a --
23 there's a series of unit costs you'll see when the
24 Board -- when the Board tends to get done with Hydro,
25 the GSL over -- over a hundred kV tends to be energy

1 somewhere down below three (3) cents and -- and demand
2 somewhere around three (3) to four dollars ($4) by the
3 time Hydro changes the methods, every time energy's up
4 over four (4) cents or up around four (4) cents and --
5 so tho -- those are quite relevant and they're --
6 they're frequently used to -- to assess different
7 components of the rates or different components of the
8 methods.
9 MR. BRADY RYALL: So -- but in the
10 context of the rate design itself, you're -- you're
11 satisfied to wait until the time of use rates are
12 considered?
13 MR. PATRICK BOWMAN: Yes.
14 MR. BRADY RYALL: Okay. Another item
15 that was in the Board's pre-hearing conference order
16 was the service extension policies. And for your
17 particular clients the -- Hydro's policy, I believe,
18 is that the -- your clients will be responsible for
19 the cost of any dedicated facilities, and even the
20 cost of some upgrades to shared facilities.
21 And I'm just throwing it out there. Do
22 you have any comments or concerns or anything you'd
23 want to bring up at this point in time?
24 MR. PATRICK BOWMAN: We haven't
25 prepared any testimony on it. I -- I'm happy to

1 comment if it helps. But the -- the clients did
2 express to -- to me -- and part of the reason we
3 suggested it be -- it be addressed for the Board,
4 fairly -- some fairly acute concerns about the system
5 extension policies and the way those were applied by
6 Hydro.
7 They also have expressed a concern
8 about interpretations as to whether they have any
9 option for relief before this Board if -- in the event
10 they don't -- don't feel they're being treated fairly
11 by Hydro because right now those -- you know, if a
12 customer wants to connect to hydro, they phone up
13 Hydro and say, I need a new line.
14 And Hydro will -- will send them a
15 quote, send them a study. And if the customer doesn't
16 like it, the -- the common understanding that's been
17 applied is, Take -- take it or leave it. And this
18 Board has no -- has no role.
19 I think there are some different issues
20 I won't get into about different legal interpretations
21 and whether that's true or not, but in practice, every
22 time one (1) of those issues comes up, the client
23 says, I have to get through a legal jurisdictional
24 issue before I can ask the Board if I'm being treated
25 fairly?

1 And that's where the -- the acute
2 concern came up, and they -- they asked that we pursue
3 it as scope. We -- we didn't have time to include it
4 in the evidence. If it was, I didn't know what I'd
5 include given some of this uncertainty about whether
6 there is a jurisdictional question.
7 And -- and my understanding is people
8 will be looking to try to have some further
9 discussions on that as -- as time goes on. But it --
10 it didn't make it in this -- in this submission.
11 MR. BRADY RYALL: Okay. Well, thank
12 you.
13 THE FACILITATOR: Questions from the
14 Board...?
15
16 (BRIEF PAUSE)
17
18 THE FACILITATOR: No?
19 Kelly, not much for you, but try and
20 get in a couple of questions.
21
22 CONTINUED CROSS-EXAMINATION BY MS. KELLY DERKSEN:
23 MS. KELLY DERKSEN: Shooting from the
24 hip here. Mr. Bowman, with respect to DSM -- and I
25 understand that there are differing perspectives on

1 how one ought to handle DSM cost assignment within
2 cost of service, and understanding that there could be
3 significant changes on the horizon with respect to how
4 DSM is administered, would it be a fair comment to
5 make -- or perhaps you can offer up your comments on
6 whether this is an appropriate time to make a change
7 in cost allocation methodology with respect to DSM,
8 recognizing of course that how we've handled DSM has
9 been -- notwithstanding Order 116/08, has been
10 consistently applied for, what, I guess twenty (20)
11 years or so in terms of direct assignment against
12 those customer classes who are participating?
13 MR. PATRICK BOWMAN: I'd only say that
14 DSM allocated to the classes is -- is simple. It
15 strikes me as fair. The one (1) time we tried to go
16 away from that, it ended up with a massive amount of
17 confusion that you were trying to relay at the last
18 workshop.
19 The -- it took a number of times of
20 people having very confused attempts in words to
21 describe mathematics that only got worse every time
22 someone tries to describe it.
23 And -- and this method has -- is -- I
24 would -- I'm not sure I'd recommend it in other
25 places, but given the DSM that -- the framework that

1 exists in Manitoba is -- is easy to apply and
2 workable.
3 And -- and I think, with the
4 uncertainty about what's happening with DSM
5 programming and how those costs will be -- will be
6 experienced in the future, whether it's through Hydro
7 or through another agency and the like, this -- this
8 is simple, practical, and -- and I don't think it
9 changes the numbers that much in terms of a way to go
10 for -- for the purposes of this hearing.
11 MS. KELLY DERKSEN: And one (1) -- one
12 (1) other question on a different matter with respect
13 to -- to exports. Can you tell me, Mr. Bowman, how
14 influential that opportunity sales would have been in
15 terms of the economic business case that would have
16 driven the decision to pursue hydraulic infrastructure
17 in the 1950s, '60s, and '70s, please?
18 MR. PATRICK BOWMAN: I -- I certainly
19 can't tell you apart from the '50s and -- and '60s. I
20 -- I can't recall the -- the concepts of opportunity
21 versus dependable, you know, like even -- even being
22 mentioned in any of the old literature that I -- that
23 I've reviewed.
24 MS. KELLY DERKSEN: That's what I
25 expected to hear from you. And where I was going with

1 this is trying to understand how does then one define
2 what the economic identity is for those facilities
3 under the assumption, of course, that exports did not
4 influence the decision to build hydraulic, let's say,
5 in comparison to thermal, which has been one (1) of
6 your tests.
7 So on that basis, and also on the basis
8 that dependable sales and opportunity sales are
9 fundamentally different services or products, and that
10 dependable are firm, we have some sense of the types
11 of revenues that we will expect from them.
12 Opportunity sales are variable,
13 arguably short-term, and certainly we have no
14 certainty as to what the price for opportunity sales
15 will be.
16 Is -- is it really your evidence, Mr.
17 Bowman, that opportunity sales should be assigned a
18 full fixed share of embedded cost responsibility on
19 those two (2) basis, number one, that many of the
20 decisions in the past were not influenced by those
21 sales, and number two, very different products in
22 terms of dependable and opportunity sales?
23 Can you -- can you help me rationalize
24 that, please?
25 MR. PATRICK BOWMAN: Sure. I agree

1 with you that they're very different products. And in
2 the event that you had an export customer who is
3 entitled to regulated embedded rates set by the PUB on
4 the basis of a Cost of Service Study, I think that
5 they would have a very good argument that for the
6 purposes of calculating their revenue cost coverage
7 ratio you would look at opportunity and dependable
8 different.
9 But that's not what we're doing here.
10 We're only trying to say what share of the bricks and
11 mortar should be properly considered to be linked to
12 exports before we move on and -- and allocate the
13 remainder to domestic customers and define something
14 called a net export revenue that could be positive or
15 negative, but -- but is -- is thought to be above cost
16 unlinked to any decision, unlinked to any investment
17 type of money.
18 And when you have that purpose of an
19 export class you have to make sure that before you --
20 you go ahead and define that in that export revenue
21 any of the revenues that were assumed to be needed to
22 justify the bricks and mortar that were built, surely
23 need to be credited against paying for those bricks
24 and mortar before they become this net export revenue
25 jiggery pokery, I believe was your term.

1 THE FACILITATOR: One (1) more?
2 MS. KELLY DERKSEN: If there is time I
3 would pass it over to Christensen for a question or
4 two (2).
5
6 (BRIEF PAUSE)
7
8 THE FACILITATOR: These areas are --
9 are really at the heart of -- of the whole hearing
10 process. So I'm kind of encouraged to perhaps carry
11 on just a little bit more and have a couple questions
12 and -- and then we'll end up moving in. But I think
13 our timeline -- I'll check some further things, but I
14 think our timeline as we get towards Thursday is much
15 better than it is at this time.
16 So then maybe we can shovel things a
17 little bit in that direction. Anyways, how about no
18 more than two (2) questions.
19
20 CROSS-EXAMINATION BY MR. MICHAEL O'SHEASY:
21 MR. MICHAEL O'SHEASY: Very good. I
22 appreciate you shovelling it my way, Mr. Grant. I --
23 and I promise I shall try to be very brief. Mr.
24 Bowman, it's nice to talk with you. I'm sorry we
25 can't see each other, but trust me, I'm over here.

1 Would -- first question, would you
2 agree that in a competitive market demand plays a
3 role?
4 MR. PATRICK BOWMAN: In a competitive
5 market demand plays a role?
6 MR. MICHAEL O'SHEASY: Yes.
7 MR. PATRICK BOWMAN: Yes.
8 MR. MICHAEL O'SHEASY: Yes. And
9 certainly the wholesale electricity market is
10 competitive, and therefore, demand does play some
11 role. And yet in SEP prices you said earlier that SEP
12 prices have, I believe you said no demand component.
13 Is that correct? And if so, how is
14 that the case?
15 MR. PATRICK BOWMAN: Well, I -- I --
16 in a competitive market demand plays a role.
17 Competitive markets are -- are very poor at dealing
18 with demand and it's part of the reason that
19 competitive electricity markets were developed early
20 and competitive -- and -- and the demand components
21 are -- are lagging and they're -- have -- have a whole
22 bunch of -- of issues with them, and we'll see that as
23 -- as demand switches from long to short in the -- in
24 the future if that arises.
25 But the SEP prices are a -- a short-

1 term price and the way that Hydro uses them that it --
2 it averages them across large numbers of hours. And
3 if -- if there was a demand component in them it's --
4 it's fully muted. I'm not going to comment on whether
5 there is a significant demand component in them
6 because I -- I'm afraid I -- I -- even at the scale
7 that Hydro is using them I -- I'm not sure that it's -
8 - that it's showing up in terms of a short-term demand
9 component.
10 MR. MICHAEL O'SHEASY: Okay. Thank
11 you. And I believe SEP prices are non-firm, but
12 whether they are or not they -- they are definitely
13 short term. And in that regard, they -- they're quite
14 similar to what I guess in the export market we call
15 opportunity sales. Wouldn't you --wouldn't you agree?
16 MR. PATRICK BOWMAN: Yes.
17 MR. MICHAEL O'SHEASY: Okay, very
18 good. Thank you. And a concern I have, it's -- it's
19 clear to me that when we allocate fixed cost to
20 dependable sales, as I've looked at PCOSS studies, it
21 appears to me that the revenue that I see over there
22 associated with dependable sales covers its cost.
23 Now, if -- if that is true, and -- and
24 I don't think it has to be because I think that the
25 price set for these dependable sales is from a

1 competitive market, but it does appear that they cover
2 the allocated fixed cost, too, when I look PCOSS.
3 But with opportunity sales, I'm a
4 little concerned that if -- if we were to allocate
5 fixed costs to opportunity sales, because once again
6 the opportunity sales price is set in a competitive
7 market with no look at what embedded costs are, if we
8 did then associate embedded cost with those
9 opportunity sales prices is it possible that they
10 would show a negative margin?
11 MR. PATRICK BOWMAN: Well, not in the
12 -- not in the current PCOSS for sure. I -- I have a
13 sheet here which I was waiting with bated breath for
14 Hydro to -- to pull out. It was -- Hydro was kind
15 enough to run the scenarios through their cost of
16 service model that we had recommended. It's -- it's a
17 very useful one (1) page summary.
18 And they were kind enough to attach to
19 us the full Excel models of -- of running the
20 recommendations. It doesn't hit every one of our
21 recommendations, but almost all of them. And the end
22 result of this scenario is the next export revenue is
23 50 million to the good.
24 MR. MICHAEL O'SHEASY: Well, I'm
25 comforting to hear that. I'm -- I'm just not sure

1 that that would be the case in the future, depending
2 on how prices fell out and how embedded costs fell
3 out, but --
4 MR. PATRICK BOWMAN: Well, the --
5 frankly to -- I -- I can't guarantee it either but
6 remember we're bringing in Keeyask that's going to be
7 4,400 gigawatt hours, and it's going to have a first
8 year cost of twelve (12) cents with -- with revenues
9 that come on, even the dependable part, of the numbers
10 that are there of about -- of about eight (8) cents.
11 So if -- if the concern is that -- is
12 that under certain situations new assets could --
13 could drive your export revenue components to -- to be
14 negative, that -- that arises even with -- even with
15 dependable sales, as long as you're -- you're dealing
16 with that reality.
17 MR. MICHAEL O'SHEASY: This actually
18 might but I -- I think dependable sales are less like
19 to -- to be negative than opportunity, but I guess
20 that's my personal opinion.
21 MR. PATRICK BOWMAN: That's true.
22 You're -- you're correct. They are less likely, but I
23 don't think it's a given that -- that either wouldn't.
24 MR. MICHAEL O'SHEASY: Yeah, okay.
25 I'm trying to move along real quick. Just one (1)

1 more? On -- on the Dorsey treatment, and I -- I'm
2 going to read real quickly what's in your -- your
3 evidence here. It says -- and this is -- I guess it's
4 on page 28:
5 "However, it's also been recognized
6 that Dorsey's converter components
7 play a necessary role in supporting
8 the ac system. At the time of the
9 2001 status update proceeding were
10 included in the Hydro transmission
11 tariff. This is important as
12 inclusion in the transmission tariff
13 means that external parties seeking
14 to submit power through Manitoba..."
15 And so forth. If -- if that decision
16 back then had been made that Dorsey was indeed not a
17 transmission component, was a gen -- but instead was a
18 generation component, would your opinion on the
19 treatment of the Dorsey converter be the same as you
20 indicated here, or would it have been to continue as
21 the decision was made in '01?
22 MR. PATRICK BOWMAN: You know, I -- in
23 -- in fairness, I actually can't say. And I've --
24 I've noted this before. Dorsey is a -- Dorsey is not
25 a slam dunk either way. Dorsey is a -- it's a -- it's

1 a weird combination. It's -- it's clearly a dc to ac
2 component. It's clearly linked to Dipoles I and II.
3 As long as you think Bipoles I and II are a driveway,
4 Dorsey is the -- I don't know what, mailbox at the end
5 of the driveway. The analogies start to break down.
6 But -- but it -- it does -- and I think
7 if -- if Hydro had never taken this view and -- and
8 defended Dorsey as part of the transmission, it's my
9 doubt -- I -- I doubt we -- we would ever initiate it
10 or -- or sort of bought into it, but having spent time
11 reviewing their rationale, knowing how they charge
12 their transmission tariff at the time, and -- and as
13 far as I can tell there's a major footnote there at 49
14 I'd still like to clarify. But, as far as I can tell,
15 still -- I -- I think that opens the door to saying
16 Dorsey's a mixed function asset and -- and it gets --
17 it leads one to not want to overuse that generation-
18 related classification for something like that.
19 But I have to say, in terms of all of
20 the recommendations in the -- in the evidence, that's
21 probably one (1) of the -- one (1) of the ones that --
22 that, I think, with further discussion or debate, it
23 could frankly go either way.
24 THE FACILITATOR: Let's leave it
25 there. Could we take only eleven (11) minutes for the

1 break? How about until twenty-five (25) to 3:00 --
2 MR. PATRICK BOWMAN: Mr. Grant, can I
3 -- can I speak to one (1) really quick comment? There
4 was one (1) thing in your outline that you thought
5 people should address, and it was one that,
6 unfortunately, I didn't put a slide on. But it was,
7 of the list of proposed methods that Hydro has put in
8 PCOSS-14 that are changes from past Board practice, do
9 we have a comparison of what we agree with and what we
10 don't.
11 And I've never framed it that way, but
12 that is one that, if -- if it was still thought to be
13 something that was important to go through that list,
14 I -- I could have that available. But I just wanted
15 you to know that that one I didn't address out of your
16 list.
17
18 (WITNESS STANDS DOWN)
19
20 THE FACILITATOR: I think we're so
21 late that let's try and move on to Bill after the
22 break. So twenty-five (25) to 4:00, please.
23
24 --- Upon recessing at 3:24 p.m.
25 --- Upon resuming at 3:36 p.m.

1 THE FACILITATOR: Bill, the panel's
2 here. I think we should get started on the
3 presentation.
4 MR. ALEX NISBET: Thank you. On
5 behalf of the Consumer Coalition, I'd like to thank
6 you having -- for having us here today. To my right I
7 have Mr. Bill Harper, of Econalysis, who will be
8 providing a presentation. With me behind us we have
9 Ms. Gloria DeSorcy, who's the executive director of
10 the Consumers' Association of Canada (Manitoba),
11 Donald Benham (phonetic), of Winnipeg Harvest, who's
12 the other half of the Consumer Coalition who's not
13 able to join us today.
14 On behalf of the Coalition, I'd like to
15 extend a warm welcome to Board Member Ring who's
16 joining us in his first PUB proceeding.
17 Today we have two (2) exhibits that we
18 have handed out. The first one (1) is Exhibit number
19 16, which is the acronym list. And Coalition Exhibit
20 number 17 will be Mr. Harper's presentation that he
21 will be providing today. And with that, I will pass
22 the mic over to Mr. Harper.
23
24 --- EXHIBIT NO. COALITION-16: ACRONYM LIST
25

1 --- EXHIBIT NO. COALITION-17: Mr. Harper's
2 presentation
3
4 CONSUMER COALITION PANEL:
5 WILLIAM HARPER, Sworn
6
7 PRESENTATION BY CONSUMER COALITION:
8 MR. WILLIAM HARPER: Good -- good
9 afternoon, everybody. As Alex said, my name's Bill
10 Harper. I'm an associate with Econalysis Consulting
11 Services. And in conjunction with that consulting
12 firm I've assisted clients participating in regulatory
13 proceedings on cost of service matters such as this in
14 -- in Ontario, Quebec, Bri -- British Columbia and
15 Saskatchewan and -- and here in Manitoba on previous
16 occasions.
17 As Alex also said, I'm here to speak to
18 the evidence I prepared on behalf of the Consumers'
19 Association of Canada (Manitoba) and Winnipeg Harvest,
20 which, as he's indicated, is fondly referred to as the
21 Coalition, regarding Manitoba Hydro's cost of service
22 methodology proposals.
23 The list of acronyms that -- that was
24 distributed, I really tried to capture in that any of
25 the acronyms that appear either on my slides or that

1 I'll probably be using during my -- during my
2 presentation because I know this industry is full of
3 short forms that even the best of us have a hard time
4 following sometimes.
5 And if you would go -- go to the next
6 slide, please. For purposes of this proceeding, I was
7 engaged by the Coalition to assist them, 1) with their
8 -- with their participation in the overall process,
9 but also to provide in the form of evidence an
10 independent and objective review of Manitoba Hydro's
11 proposed cost of service methodology. And this is
12 what was filed with -- with the PUB on June 10th.
13 The evidence attempts to go through the
14 entire cost of service methodology, not just the main
15 generation transmission pieces that Manitoba Hydro has
16 focussed on, and identify those areas where I agree
17 with Manitoba Hydro's cost of service methodology, and
18 also those areas where I don't.
19 The evidence concludes with a series of
20 recommendation regarding areas where I believe the
21 methodology should be changed, areas where the data
22 currently used could be -- could be updated and
23 improved, and this is primarily by updating it to
24 reflect more current values for a num -- number of the
25 weighting factors that are used in the various

1 allocations.

2 Third, the evidence goes through and

3 identifies areas where the cost of service model that

4 Manitoba Hydro uses I believe could be improved as

5 well, primarily by incorporating some of the costs

6 functionalization that's currently done outside of the

7 model into the model itself so it can be carried

8 through to the sub-functionalization stage.

9 And probably more important, when the

10 Cost of Service Study itself starts moving assets

11 between functions, as it does in the case of Dorsey,

12 the -- some of the other costs that should probably

13 follow Dorsey go -- go along -- go along with it

14 because the cost allocation has all -- all bee

15 internalized as part of the model itself.

16 And finally, the report summarizes a

17 number of data input corrections that have been noted

18 by Manitoba Hydro during the interrogatory process.

19 If we could have the next slide,

20 please. Given that I've only got half an hour and

21 Bill's standing with -- with the hook, my -- my plan

22 was not to go through all of the recommendations in

23 the evidence, but really -- rather deal with just the

24 more substantive ones in areas where I agree or

25 disagree with Manitoba Hydro.

1 In terms of areas where I disagree, I
2 propose to address the treatment of DSM, the proposal
3 by Manitoba Hydro to include a capacity adder in the
4 weighted energy allocator it uses for -- for
5 generation costs, and the allocation of non-tariffable
6 transmission costs.
7 In the areas where I agree with
8 Manitoba Hydro, I propose to speak to the question of
9 whether there should be one (1) or two (2) export
10 classes, the treatment of Bipole III and Dorsey, the
11 overall use of a weighted energy allocator for
12 generation costs, the treatment of interconnections,
13 and finally the treatment of the uniform rate
14 adjustment and the costs associated with the
15 Affordable Energy Fund.
16 Can we have the next slide, please?
17 With regard to the treatment of DSM, the evidence
18 disagrees with Manitoba Hydro's proposal to directly
19 assign the costs of DSM to customer classes based on
20 customers' participation in various programs.
21 Instead, the evidence proposes that DSM
22 costs should be viewed as a resource option. This
23 would involve assigning the costs to generation,
24 transmission, and distribution, and then allocating
25 them to the various customer classes along with the

1 other costs that -- that have been attributed to each
2 of those functions.
3 The rationale for this proposal is
4 that, as recommended by the -- by the PUB in its 2014
5 NFAT report, Manitoba Hydro has adopted an integrated
6 resource planning approach. As a result, DSM is
7 considered a resource option and evaluated on
8 equivalent footing with supply-side options such that
9 approved DSM programs form part of Manitoba Hydro's
10 Least-Cost Plan for meeting domestic requirements.
11 While customers will benefit in terms
12 of lower bills from any DSM initiative they undertake,
13 the key point and the focus of Manitoba Hydro's DSM
14 programs is that they target savings opportunities
15 that would not otherwise be undertaken by customers
16 and that are all too economic from the utilities
17 perspective.
18 Customers are then encouraged to
19 participate in these programs, often through financial
20 incentives, such that it is Manitoba Hydro that is
21 really causing these costs to be incurred. Indeed,
22 DSM programs are frequently redesigned to increase
23 participation if the utility's experience to date has
24 not met its expectations in terms of what the level of
25 participation will be.

1 In my mew -- view, this is a
2 fundamentally different circumstance from one where a
3 customer seeks service from Manitoba Hydro, and as a
4 public utility, it is Manitoba Hydro's obligation to
5 provide service.
6 Manitoba Hydro is under no similar
7 obligation to provide DSM programs. It does so
8 because they provide a benefit to the system overall
9 and choices to which programs to pursue is guided by
10 this consideration.
11 Finally, under the Manitoba Hydro
12 approach, if all the customers in a class were to
13 participate in a particular DSM program, then the
14 allocated costs of the -- and the costs are allocated
15 directly to them, then this would effectively result
16 in clawing back any financial incentive that the
17 customers had to participate.
18 And indeed, when I read Mr. Bowman's
19 evidence, I -- I believe this and the way DSM costs
20 are treated is fundamentally the problem that's
21 created for -- for the curtailable rate class that he
22 was speaking to in his evidence.
23 Can we have the next slide, please?
24 Oh, that didn't come out very well, did it. I -- I
25 apologize for that. It -- hopefully it came out

1 better on the hard copy. I have only one (1) in front
2 of me. No? I don't know what happened there.
3 One (1) way of implementing my proposed
4 approach is to take the same avoided costs for
5 generation, transmission, and distribution used to
6 screen the DSM programs, and to use these costs to
7 apportion DSM program costs to generation,
8 transmission, and distribution.
9 Based on the avoided cost used in the
10 DSM plan reflected in the Integrated Financial
11 Forecast that PCOSS14 is based on, this should result
12 in an allocation where roughly 86 percent of DSM
13 program costs are allocated to generation, 7 percent
14 are allocated to transmission, and roughly 7 percent
15 are allocated to distribution.
16 I should note that BC Hydro treats DSM
17 costs as a resource option in their Cost of Service
18 Study, and their most recently approved breakdown is
19 90 percent, 5 percent, and 5 percent, which is not
20 that much different from what you're seeing here.
21 Out of all the changes I recommended in
22 my evidence to Manitoba Hydro's cost of service
23 methodology, this one (1) has the greatest impact, and
24 the results are set out here on the -- on -- on the
25 slide. What's probably most important is the far

1 right-hand corner -- column, which is the one we
2 actually can see.
3 I should point out that both these
4 results and the PCOSS amended results I am comparing
5 them to have been updated to incorporate the various
6 data corrections I -- I talk -- talked about earlier,
7 and therefore the comparisons you're seeing here are
8 strictly the impact of the change in the allocation of
9 DSM costs.
10 Looking at the impacts, the DSM
11 treatment change I'm proposing has the most favourable
12 impacts on the general ser -- service small, and the
13 general service larger greater than one hundred (100)
14 customer classes where the increases in the revenue
15 cost coverage ratios are all in excess of 1 percent.
16 On the flip side, the customer class with the most
17 unfavourable impact is resi -- residential where the
18 ratio declines by 1.3 percent.
19 Could we move onto the next slide
20 panel? Another substantive area where my evidence
21 disagrees with Manitoba Hydro is with regard to the
22 addition of a capacity adder to the weighted energy
23 values used in the allocation of the generation cost.
24 My conclusion based on the evidence I've seen is that
25 the inclusion of such an adder is premature,

1 particularly for PCOSS14 amended.

2 Since first adopted in 2005, the

3 weighted energy allocator has been based on the

4 relevant surplus energy program prices in each of

5 twelve (12) different time periods. The argument for

6 now, including a capacity adder, is that while SEP

7 weightings adequately reflect the capacity -- capacity

8 considerations when first introduced in 2005 there

9 have subsequently been changes in market conditions

10 such that this is no longer the case, and an adder is

11 needed.

12 The market conditions specifically

13 noted by CA Consulting is the initiation of a

14 voluntary capacity market by MISO starting in 2009,

15 which meant that prices for opportunity sales may no

16 longer reflect the scarcity or capacity premium to the

17 extent they used to.

18 However, since the historical data that

19 Manitoba Hydro uses to determine the period weightings

20 in this particular cost of service is based on the

21 period 2005 to 2012. Even if this was the case, a

22 capacity adder should -- should not be included for

23 all the years as Manitoba Hydro has done, but best for

24 the years 2010 to 2012, the years after the

25 introduction of -- the start of this particular

1 market.

2 Furthermore, the more formal MISO

3 planning resource option, which Manitoba Hydro does

4 participate in, was not initiated until 2013 which is

5 after the span of the historical years they -- they've

6 used to -- to come up with -- with the weightings

7 which begs the question as to whether an adder should

8 be included at all for the years 2000 -- for even

9 years 2010 to 2012.

10 My second concern with the

11 incorporation of a capacity adder is that the capacity

12 prices in the planning resource option market are

13 extremely low, roughly ten (10) cents per kilowatt per

14 month, relative to the cost of a single cycle

15 combustion turbine which people typically think as a

16 peaker to provide capacity, which is roughly fifty

17 (50) times high -- higher than that. And the prices

18 in the early voluntary market were typically even

19 lower than that ten (10) -- ten (10) cents per

20 kilowatt a month. Thus, if there was some transfer of

21 capacity value over to the market it was minimal real

22 -- it -- it was very minimal at most.

23 Third, the introduction of the

24 voluntary capacity market in 2009 coincided with the

25 economic downturn and with the drop in natural gas

1 prices. And Manitoba Hydro acknowledges that the drop
2 in the peak period opportunity prices cannot be
3 directly attributed to the introduction of a capacity
4 market. There were other forces going on at play at
5 the same point in time. Can we have the next slide,
6 please?
7 Because finally, and probably most
8 telling from my perspective, is the fact that as shown
9 here even without a capacity adder in the peak period
10 -- the peak period weightings in PCOSS14 amended are
11 higher in all seasons than the weightings in Manitoba
12 Hydro's earlier cost of service studies that pre-dated
13 2009. In all cases, you'll note the -- the values are
14 considerably higher in either PCOSS06 or PCOSS08.
15 Overall, I believe the question of
16 whether or not the capacity adder should be included
17 requires more consideration first in terms of is one
18 really needed, and then if -- if so, what hours, what
19 season should be incorporated, and what value should
20 actually be used. Can we have the next slide.
21 Another area where I disagree with
22 Manitoba Hydro is with respect to the treatment of the
23 non-tariffable transmission subfunction. Manitoba
24 Hydro allocates the cost in this subfunction to both
25 domestic and export load. However, in my view the

1 cost should only be allocated to domestic load using
2 the same 2CP allocator as Manitoba Hydro currently
3 uses.
4 Manitoba Hydro has explained in
5 accordance with its coordination agreement with MISO
6 it relies on the seven (7) factor test and used and
7 useful criteria both established by FERC to determine
8 tariffable transmission facilities and that this non-
9 tariffable subfunction has been introduced to
10 specifically capture the cost of transmission
11 facilities that are no eligible for inclusion in its
12 open access tariff.
13 Since by definition these facilities
14 are not considered as eligible for inclusion in the
15 open access tariff it would only seem appropriate to
16 exclude exports from their allocation base, and
17 thereby maintain a consistent treatment between the
18 way assets are treated for purposes of setting the
19 open access tariff and the way assets are treated for
20 purposes for of the Cost of Service Study.
21 I should note, and you will see later
22 on in the presentation that consistency between the
23 treatment of assets for purposes of the open access
24 tariff and the Cost of Service Study is one (1) of the
25 reasons why I actually agree with Manitoba Hydro in a

1 num -- number of other areas of its cost of service
2 methodology.
3 This next slide indicates the impact of
4 this change in the allocation is -- is minimal with
5 most customer classes seeing a change in the revenue
6 to cost ratio of no more than 0.1 percent either up or
7 down.
8 The only exception is the diesel class,
9 which sees a 0.3 percent increase, primarily due to
10 the increase in net export revenues that occurs when a
11 share of these costs are no longer allocated to the
12 export class.
13 However, I think a word of caution is
14 needed. Manitoba Hydro has indicated that it still
15 needs to clean up the designation of some of its
16 transmission lines. And you've heard some discussion
17 around that earlier this morning. And so the -- the
18 cost in the subfunction may change and therefore the
19 overall impacts may change going forward as well.
20 Can we to go to the next slide? As I
21 indicated at the start, there were a number of areas
22 where I agree with Manitoba Hydro's proposal and I'd
23 like to go some -- through some of the key ones. The
24 first one (1) is with respect to exports and the use
25 of two (2) as opposed to one (1) export class as well

as the definitions used for dependable and opportunity exports.

First, I support the overall approach of formally including exports as a class in the Cost of Service Study. Exports are significant to Manitoba Hydro in terms of the revenues generated both in total, and on a megawatt per hour basis.

They're significant in terms of their impact on operations and they're also significant in terms of their impact on investment planning. With regard to this last point, Manitoba Hydro's firm export commitments are included in both generation and transmission planning.

And as well, we're all aware that the potential for additional export revenues has influenced the timing of Manitoba Hydro's recent investments in Wuskwatim and its ongoing investments in Keeyask. The inclusion of an export class allows the Cost of Service Study to formally recognize this and to allocate exports at a reasonable share of both fixed and variable costs for purposes of establishing net export revenues.

However, having recognized the need to allocate both fixed and variable cost to exports, it's also important to recognize in this allocation that

there are clear differences between domestic and export load in terms of reliability, even -- even in the case of dependable exports.

As we heard here during the May workshop, Manitoba Hydro does not carry a planning reserve for dependable exports as it does for its own domestic load. An export contract has curtail -- curtailment provisions in them that can be activated when continuing to serve exports would jeopardize Manitoba Hydro's firm load.

These differences suggested from a fairness perspective expert load, even firm exports should not bear the same cost responsibility as domestic load. There are also clear differences between exports and domestic load in terms of how they influence utility planning.

Manitoba Hydro only invests to support additional exports if there's an overall benefit to domestic customers, i.e., lower rates over the long-term. In contrast, Manitoba Hydro is required to plan to meet new Manitoba -- new Manitoba domestic load and must do so even if the investments lead to higher rates.

Again, this difference, which suggests that exports should bear less cost responsibility than

1 firm load.

2 Could we go to the next slide, please.

3 It is therefore reasonable in my mind to conclude that

4 if only one (1) export class is used it would be

5 inappropriate to allocate a cost on a similar basis to

6 domestic load, because this would clearly over --

7 result in an over allocation of cost exports.

8 However, it would be equally

9 inappropriate to allocate the export class no fixed

10 costs at all. This means that adopting one (1) export

11 class requires a decision as to the relative con --

12 cost responsibility of exports versus domestic load.

13 The problem with trying to come up with

14 such a factor is that there -- there are a variety of

15 export sale -- sales arrangements with varying degrees

16 of reliability and that the decision to invest in

17 exports is based on a totally different economic

18 paradigm than decisions to invest in -- in domestic

19 load.

20 The result, in my mind, is the

21 determination of an appropriate cost responsibility

22 factor for one (1) export class is likely highly

23 impractical and any number you come up with would be

24 extremely arbitrary.

25 In contrast, I see the use of two (2)

1 export classes based on dependable versus opportunity
2 sales as being a workable alternative that builds on
3 the fact there is a distinct difference between the
4 two (2) in terms of reliability, their influence on
5 planning, and their impact on any decision to advance
6 the investment in new generation.
7 The overall result is one where exports
8 in total attract some fixed costs but not as much as
9 domestic load, which in my mind is far superior and
10 more reasonable than having exports attract a
11 equivalent to fixed costs or no fixed costs at all.
12 Can you go to the next slide, please?
13 With respect to Bipole III, I agree
14 with Manitoba Hydro's proposal to treat the facility
15 as generation and allocate its costs accordingly as
16 opposed to treating it as transmission. There are
17 several reasons for this.
18 First, the purpose of Bipole III is
19 similar to that of Bipole I and Bipole II, and that is
20 to ensure the availability of sufficient generation to
21 do the system.
22 Second, Manitoba Hydro has confirmed
23 that, in accordance with the coordination agreement
24 with MISO, Bipole III will non-tariffable, i.e.,
25 ineligible for inclusion in Hydro's open access

1 transmission rate. Thus, treating Bipole III as -- as
2 generation for cost allocation purposes is consistent
3 with its treatment in the open access tariff.
4 It's also consistent with the PUB's
5 view expressed in Order 7-03, that only those
6 transmission facilities which we recognize for
7 inclusion in Hydro's transmission tariff should be
8 assigned to the transmission function.
9 There have been suggestions that, since
10 Bipole III isn't directly linked to any specific
11 generation development, it should not be
12 functionalized as generation. Bipole III is meant to
13 address the potential for the simultan -- taneous
14 outage of both Bipoles I and II or the outage of the
15 entire Dorsey converter station, both -- both events
16 of which are viewed as being low probability but high
17 consequence events.
18 Material filed at the CEC hearing
19 regarding Bipole suggest that such events were not
20 even considered when the original bipoles were being
21 looked at for -- forty (40) years ago. Indeed, even
22 now there were no guidelines to finding what is an
23 acceptable level of risk for low probability but high
24 consequence events that would trigger the need for
25 investment. What there exists is the requirement that

1 utilities study such situations and have a plan, but
2 the plan is basically left up to them.
3 There has been a potential for
4 shortages for such events for a long time, as Mr.
5 Chernick was talking with Mr. Bowman about ear --
6 earlier today. And the planning for Bipole III has
7 been going on since the early 1990s.
8 Interestingly enough, during the CEC
9 proceeding Manitoba Hydro was asked what it was that,
10 at that particular time, triggered the need to proceed
11 with -- with Bipole III. And they indicated it was a
12 combination of -- of factors, including the growing
13 potential su -- supply deficit, as illustrated in the
14 graphic you've seen already, various past weather
15 events that caused the failure of Bipoles I and II and
16 1996, and the loss of the Dorsey bus work in 2007, as
17 well as a tornado that came dangerously close to
18 Dorsey in the same year.
19 Also, during the years, Manitoba Hy --
20 Hydro has improved its modelling that quantified the
21 weather-related vulnerability of these facilities so
22 they have a better understanding of it.
23 And, finally, as I understand it,
24 simply the fact there's been weather-related blackouts
25 in other jurisdictions ha -- have sort of raised this

1 in pe -- people's consciousness. As a result in my
2 mind, the fact that Bipole III is not being
3 constructed simultaneously with new generation cannot
4 be viewed as an indication that it's not needed as
5 part of the overall HVDC system that -- that is
6 required in order to reliably deliver generation to --
7 to the grid.
8 Clearly, Manitoba Hydro's justification
9 for the construction of Bipole III was -- was
10 precisely for that purpose. Go to slide 13, please.
11 We also agree with Manitoba Hydro's
12 proposal to treat the converter station at Dorsey, and
13 also the future Riel station, as part of the
14 generation function while treating the AC facilities
15 at both locations as transmission.
16 The Dorsey converter is effectively the
17 last step in integrating northern generation into the
18 Manitoba Hydro grid and is an integral part of the
19 overall bipole HVCD system.
20 Furthermore, according to Manitoba
21 Hydro, the Dorsey converter station is -- is non-
22 tariffable. And that was the direction we -- that was
23 an issue we put directly to them in -- in the
24 interrogatories and got -- got a specific response in
25 Coalition 37.

1 And so its not being eligible for
2 inclusion in Manitoba's open access tariff also
3 suggests that it should not be included in
4 transmission for purposes of the cost of service
5 study.
6 In its 2012 recommendations to Hydro,
7 CA Consulting suggested that Manitoba Hydro may wish
8 to functionalize the converter at Dorsey as generation
9 after accounting for a share of the cost that would
10 have been placed in service otherwise to maintain
11 reliability of the transmission system. In its 2015
12 report, CA Consulting recommended based on simulation
13 studies done by Manitoba Hydro that no more than 25
14 percent of the converter costs should be assigned to
15 transmission.
16 However, CA Consulting also noted that
17 the results were highly specific to the model
18 parameters, the system conditions, and the assumptions
19 used in the modelling, and that other assumptions or
20 approaches would most likely lead to different
21 results.
22 In fact, if -- if I go to the British
23 Columbia example, which -- which is the other issue
24 area we've been talking about where there's generation
25 related trans -- transmission, in 1998 when the BCUC

1 made its initial determination regarding the treatment
2 of certain transmission lines as generation related,
3 it faced a similar issue with various parties adopting
4 different approaches for establishing the portion of
5 the lion's cost that should be treated as tran --
6 transmission because they were contributing to -- to
7 stability on the overall system.
8 In the end, the BCUC concluded that the
9 exercise was high -- highly subject. Everybody came
10 through with their own modelling, with their own
11 proposal, with their own number, and at the end the
12 BCUC directed that 100 percent of the line should be
13 treated as generation related transmission. A similar
14 por -- approach for Dorsey is a reason -- reasonable
15 one to take here, in my mind.
16 Finally, while there's no project
17 justification form for the initial Dorsey project, it
18 is worthwhile noting that the project justification
19 form for the Riel converter makes no reference to
20 transmission stability and the been -- benefits. It -
21 - it is all about completing the -- the Bipole III and
22 the integration of -- of Bipole III in -- into the
23 grid. Go -- go to the next slide, please.
24 I agree with Manitoba Hydro's approach
25 for generation costs, which is to notionally classify

1 them as energy related and the allocate the costs to
2 customer classes, including dependable exports using
3 the weighted energy approach where the weights will
4 reflect the -- the value of energy including capacity
5 considerations in each of twelve (12) periods.
6 Before I explain why, I think it's
7 important to note that when it comes to generation
8 classification and allocation, there is no industry
9 standard and no consensus. This -- this is probably
10 the most controversial area of cost of service when --
11 when you're looking at any -- any particular
12 jurisdiction. And a good illustration of that, this
13 is in the most recent negotiated settlement agreement
14 on cost of service methodologies that was approved for
15 BC Hydro.
16 "On most aspects of the cost of
17 service methodology, the parties
18 participating in the negotiation
19 were able to come to an agreement
20 with one (1) really notable
21 exception."
22 And you can guess what that was,
23 generation cost.
24 "Indeed, when it comes to the
25 treatment of generation there are a

1 wide variety of approaches that can
2 be employed by electric utilities
3 and for many of these approaches
4 there are variations that exist in
5 terms of how they can -- can be
6 implemented."
7 So that while there may be six (6) or
8 seven (7) different approaches, there's probably
9 fifteen (15) or twenty (20) different ways you could
10 do it by the time you're finished. My preference for
11 Manitoba Hydro's weighted energy approach is based on
12 the fact that it is a comprehensive approach that
13 allows for the incorporation of current cost and
14 current cost consequences of using electricity in
15 different periods.
16 Admittedly there are issues with its
17 Application in terms of satisfying ourselves that
18 there is a sufficient time differentiation, and that
19 the prices used capture both capacity and energy cost
20 considerations. But all methods have issues, which is
21 one (1) of the reasons why there's no industry
22 consensus, to be quite honest with you.
23 For -- for example, CA Consulting
24 referenced the peak credit method in its 2012 report.
25 And as I spoke with Mr. -- Mr. Bowman this morning,

1 since then Manitoba Hydro has produced two (2)
2 different estimates as to what that -- what that would
3 lead to in terms of demand costs, one being 15 percent
4 and another being 23 percent, because they looked at
5 it two (2) different ways and applied different
6 approaches.
7 This range of estimates clearly
8 indicates there are issues and variations in terms of
9 how that methodology could be implemented. There have
10 also been stability issues and concerns noted with
11 regard to the peak credit method.
12 Finally, while -- with Manitoba Hydro's
13 current approach, there is a need to ensure that the
14 period weightings adequately reflect capacity costs.
15 With the peak credit method, there is a similar issue
16 in that one would need to ensure the factors used to
17 allocate energy related costs to customer classes did
18 not include any capacity costs at all, otherwise there
19 would be an issue of double counting.
20 On balance, I viewed Manitoba Hydro's
21 proposed approach as preferable, and it addresses the
22 classification and allocation -- and allocation of
23 generation costs in a holistic manner that is
24 reflective of cost.
25 Unlike a lot of other methods, this is

1 a system load factor method that was used by Manitoba
2 Hydro prior to adopt -- adopting its current method,
3 and without having the number of moving parts that
4 many other methods such as the peak credit method have
5 and we have to worry about, as I deal with one (1)
6 part, what does that do with how the other parts are -
7 - are going to be treated in the overall allocation
8 methodology.
9 As need be, the method can be refined
10 by introducing more time periods to properly capture
11 the costs of capacity and energy. And that's an
12 improvement I think we should look at.
13 How am I doing, Bill? You're giving me
14 a signal here.
15 THE FACILITATOR: You're a little over
16 time, Bill.
17 MR. WILLIAM HARPER: Okay. Okay. I
18 guess I'll -- well, give me a real hook when you think
19 I should stop.
20 And I'll also agree with Manitoba
21 Hydro's proposed treatment of interconnections whereby
22 they're allocated to domestic customers and firm
23 exports using the weigh -- weigh -- weighted energy
24 allocator as generation.
25 The allocation to both exports and

1 domestic load recognize the fact that interconnections
2 are used both for exports and to purchase -- and for
3 purchases to support Manitoba Hydro load.
4 On the domestic side, the benefits of
5 interconnections are improved both energy and capacity
6 reliability. And on the export side, the benefits
7 come in terms of opportunity energy sales and
8 dependable exports which come in the form of blocks of
9 power, five (5) by sixteen (16), seven (7) by sixteen
10 (16). So they also have both capacity and energy
11 considerations as well.
12 The last issue with respect to the cost
13 of service methodology I'd like to speak to is the
14 treatment of the uniform rate adjustment and the costs
15 for the Affordable Energy Fund.
16 With respect to the uniform rate
17 adjustment, uniform rates are a statutory requirement
18 based on government policy. At the time government
19 indicated and introduced the legislation, it indicated
20 that its ability to implement uniform rates was due to
21 the benefits generated by export sales, and that, as a
22 result, it was not asking Manitobans to pay more.
23 Given this context, Manitoba Hydro's
24 proposed treatment whereby the impact of implementing
25 uniform rates is charged to exports seems entirely

1 consistent with the policy.

2 Similarly in the case of the Affordable

3 Energy Fund, it too is a statutory requirement. And

4 indeed, in this case, the legislation specifically

5 states that it'll be funded out of export revenues.

6 Furthermore, the uses of the fund go far beyond just

7 electricity energy efficiency and into other areas.

8 So again, I think -- think the proposal

9 to treat it and allocate it against export sales is

10 reasonable.

11 I think probably I'll -- I'll stop

12 there, Bill. And if there's time, I'll come back to

13 the last slide at some point in time.

14 THE FACILITATOR: Thanks very much,

15 Bill.

16 We have a bit of a change in terms of

17 the order as we've changing all the times in order as

18 we're going along anyways. The City of Winnipeg is

19 going to ask questions first, and switch with MIPUG in

20 terms of its time line for questioning.

21 As they get ready for asking questions,

22 there was one (1) thing that I neglected to do before

23 Bill started, and that was that, as an undertaking for

24 MIPUG, I understand they're in agreement that they

25 will provide the list where the methodology that

1 Manitoba Hydro has used has changed from previous Cost
2 of Service Studies and where MUG -- MIPUG agrees or
3 disagrees with that.
4 So that -- that chart that Patrick had
5 before he'll provide as an undertaking for the benefit
6 of that.
7
8 --- UNDERTAKING NO. 33: MIPUG to provide list of
9 Manitoba Hydro changes in
10 methodology from previous
11 Cost of Service Studies,
12 and indicate where MIPUG
13 agrees or disagrees
14
15 MS. KELLY DERKSEN: Bill -- Bill, can
16 I ask a question about that --
17 THE FACILITATOR: All right.
18 MS. KELLY DERKSEN: -- about the
19 undertaking? Is it in comparison to the last PUB
20 Board Order specifically addressing cost of service
21 matters -- in other words, 116/08? Is that what the
22 undertaking is?
23 THE FACILITATOR: No. I think in my
24 mind, what I was asking for at the time was really
25 what Manitoba Hydro's last application was, not the

1 Board's determination of that. So had they changed
2 anything from what they applied for last time, and, if
3 so, does -- does MIPUG agree with that or not agree
4 with that?
5 MS. KELLY DERKSEN: Would it be
6 reasonable that Manitoba Hydro put on the record
7 similar perspectives with respect to let's say MIPUG
8 perspectives that have not changed since that time?
9 Or I suppose you could extend that to all Intervenors
10 also.
11 THE FACILITATOR: Yes. I think that's
12 -- you know, that information will be of help to the
13 panel, so that I think that would be another
14 undertaking. This is the third undertaking to -- to
15 Manitoba Hydro to provide similar information, I think
16 it is, to the request that has been made of MIPUG from
17 it -- from its perspective of the MIPUG evidence.
18 Is that not correct? Close enough?
19 Actually, Kelly, if you can state it, you'd probably
20 do much better than me anyways.
21 MS. KELLY DERKSEN: I wasn't going to
22 restate it. I was debating what the value in doing
23 that for all parties is because -- because the fact of
24 the matter is, I mean, that's ten (10) years ago, and
25 it just adds another layer of confusion potentially,

1 number 1, and number 2, another sort of de -- deck of
2 cards to play from, so it becomes a very massive
3 undertaking to sort through that, let alone sort
4 through what we have currently on the record and in
5 play in this proceeding.
6 So I'm -- you know, I'm a bit concerned
7 about how one sorts through all of that massive
8 information.
9 MR. WILLIAM HARPER: Yes. Sorry, I
10 misunderstood. I thought you wanted to do that this.
11 I think that, if you don't want to do it, you don't
12 have to do it, no homework.
13 MR. BYRON WILLIAMS: And mis -- Mr.
14 Grant, if -- it's Byron Williams here back -- way in
15 the back here unusually quiet this week. I'll just
16 say, yeah, and it certainly is appropriate if MIPUG --
17 if that undertaking was posed to them, for them to
18 submit it.
19 It is a bit unusual for a party that's
20 not testifying to be offering an undertaking. It
21 sounds a li -- little bit more to me like new
22 evidence. And that might be appropriate if Manitoba
23 Hydro did wish to introduce it, but I think it's not
24 an undertaking.
25 And they might want to make a motion if

1 they think that's -- that's relevant, but I don't see
2 that as an undertaking. The -- the time for Hydro's
3 undertakings were in the first workshop.
4 THE FACILITATOR: Well, it sounds,
5 Kelly, as if you weren't keen on doing it anyways, so
6 why don't I withdraw that undertaking? Sorry for the
7 confusion. Over to the City of Winnipeg.
8
9 CROSS-EXAMINATION BY MS. DENISE PAMBRUN:
10 MS. DENISE PAMBRUN: Thank you very
11 much, Mr. Grant.
12 Mr. Harper, we've had some discussion
13 about -- just a minute, I have to find my notes, the
14 allocation of net export revenue. And I take it that
15 it is your pos -- well, I -- I'm not sure I have your
16 position or your views.
17 You're aware that the City of Winnipeg
18 is taking the position that next export revenue should
19 be allocated against -- not -- not directly against
20 the participating classes.
21 Do I -- you knew that?
22 MR. WILLIAM HARPER: I'm -- I'm
23 sorry, I --
24 MS. DENISE PAMBRUN: I'm sorry, I -- I
25 phrased that very badly. That net export revenue

1 should not be left out of the cost of service study?
2 MR. WILLIAM HARPER: Actually, I -- I
3 didn't see that in the evidence that was filed on
4 behalf of the City of Winnipeg, but I sort of gleaned
5 that from the questions you were posing to Mis -- to
6 Mr. Bowman. And if you say that's your position, I
7 will accept that as your position.
8 MS. DENISE PAMBRUN: All right. And
9 you're aware that if net export revenue is allocated
10 to all the classes, it is Manitoba Hydro's proposal
11 that it be allocated against only those costs that are
12 not directly allocated. Isn't that right?
13 MR. WILLIAM HARPER: Well, I don't
14 think that's quite their proposal because I think, you
15 know -- and I think maybe this is where some of the
16 confusion is coming up. And maybe the diesel is a
17 particularly good example, is because in the cost of
18 service study, tho co -- a significant portion of all
19 -- virtually all the costs are directly assigned to
20 diesel, but in the co -- but in the net export revenue
21 allocation they are included as part of the allocation
22 base.
23 MS. DENISE PAMBRUN: Right.
24 MR. WILLIAM HARPER: I think the
25 better distinction make, and I think you were --

1 somebody was exploring this morning, was that direct
2 assignments related to costs associated with
3 facilities and activities behind the customer meter,
4 or if you don't have a meter in the case of street
5 lighting, behind the point of delivery or demarcation
6 between where the Manitoba Hydro system stops and the
7 customer system starts.
8 Those types of costs should be excluded
9 from the allocation base.
10 MS. DENISE PAMBRUN: Right.
11 MR. WILLIAM HARPER: And I think
12 that's why -- you know, there's a bit of confusion
13 when you say direct assignment, but that's my
14 understanding --
15 MS. DENISE PAMBRUN: Okay.
16 MR. WILLIAM HARPER: -- if I parse it
17 down in terms of what Manitoba Hydro --
18 MS. DENISE PAMBRUN: So diesel is the
19 exception, and area and roadway lighting is a
20 situation where 70 percent of the cost allocated to
21 area and roadway lighting are direct -- directly
22 allocated, correct?
23 MR. WILLIAM HARPER: I'll accept your
24 number for purposes of our conversation, yeah.
25 MS. DENISE PAMBRUN: All right. And

1 in that case, area and roadway lighting is at a
2 disadvantage, you'd agree with me, if Manitoba Hydro,
3 which it does, proposes to assign net export revenue
4 against only the non-directly allocated costs?
5 MR. WILLIAM HARPER: Yeah, I'll agree
6 that you're at a -- you're at a disadvantage as
7 opposed to a different allocation approach, which
8 would include all costs in -- in the allocation base,
9 yes.
10 MS. DENISE PAMBRUN: And other
11 classes, which do not have nearly the same percentage
12 of directly allocated costs such as residential or
13 general service, and diesel, which is an exception,
14 have a relatively advantaged position.
15 Isn't that right?
16 MR. WILLIAM HARPER: Yes, I -- I
17 believe that's correct, yes.
18 MS. DENISE PAMBRUN: And you'd agree
19 with me that it would be a more consistent treatment
20 with say diesel -- diesel has been given an exception
21 for whatever reason?
22 MR. WILLIAM HARPER: Well, I -- I
23 guess I don't agree with your characterization that
24 diesel has been given an exception, because as I said,
25 the cost associated with diesel that are directly

1 assigned are costs that are on the system side of the
2 meter and therefore totally consistent with the types
3 of costs that are allocated to the other customer
4 classes.
5 Direct -- when we directly assign the
6 cost of diesel generation, those generating facilities
7 in the community, they're directly assigned. For all
8 other customer classes diesel is an allocated cost.
9 And so I don't agree with your characterization of the
10 way that, you know, of diesel, no.
11 MS. DENISE PAMBRUN: Okay. Well,
12 let's talk about the directly allocated cost and the
13 area and roadway lighting category then. So you're
14 aware that the directly allocated costs include
15 luminaires, right?
16 MR. WILLIAM HARPER: Yes.
17 MS. DENISE PAMBRUN: They include the
18 poles on which the luminaires are -- are held, are
19 contained, or mounted?
20 MR. WILLIAM HARPER: And maybe --
21 maybe we can be specific like that, be cumulative
22 injury think there might be two (2) different types of
23 poles here. You can talk about poles on which only a
24 street light is -- is mounted, in which case that
25 might be viewed as being a -- an asset, you know, sort

1 of on the customer side of -- of the meter.
2 You know, there might also -- I don't
3 know whether there are any pole involved where there
4 are streetlights mounted on Manitoba Hydro poles. I
5 assume if there are those poles are part of the
6 allocated costs and not part of the directly assigned
7 costs, but I don't know.
8 So there's fin -- there's -- there's
9 sort of fine points on this that I'm not familiar
10 with.
11 MS. DENISE PAMBRUN: Okay. If I tell
12 you that there are shared poles and they are directly
13 allocated to the area and roadway lighting category,
14 do you agree with me that is an inconsistent
15 treatment?
16 MR. WILLIAM HARPER: Yes, I would.
17 And actually, when we're talking about customer side
18 of the meter versus the system side of the meter and I
19 read, I believe, it's one (1) of the City of Winnipeg
20 IRs where Manitoba Hydro was specifically outlining
21 what the assets were, I know there were a number of
22 assets you say like luminaires, arms --
23 MS. DENISE PAMBRUN: Brackets.
24 MR. WILLIAM HARPER: -- photo sen --
25 sensors and those things that I viewed as being

1 clearly on the customer side of the meter. There were
2 also other things like the secondary wire, and as
3 you've informed me, poles that might more reasonably
4 be considered as being on the distribution side.
5 And when I was reading Mr. Todd's
6 evidence the piece that was missing for me, and it
7 might be interesting to have some discussion about it
8 at some point in time, was he seemed to be assuming
9 the sini -- the majority of those costs were
10 associated with the poles and that's secondary.
11 I haven't seen any evidence on the
12 record that indicates whether those are 80 percent of
13 the cost, in which case I believe you've probably got
14 an issue. If they're 5 percent of the cost, I think
15 you've -- you know, the needle may swing the other
16 way.
17 MS. DENISE PAMBRUN: All right. And
18 so I asked some questions earlier of the first
19 witness, Mr. Bowman, about line drops. For instance,
20 let's say, and I'm not expert in these areas, but bear
21 with me, you've got a line drop that is exclusive to a
22 single dwelling.
23 It's -- it's on the Hydro side of the
24 meter, but it is exclusive to that dwelling. Now, to
25 be consistent, do you agree with me that that is -- to

1 be consistent, that should be a direct allocation to
2 the residential class?
3 MR. WILLIAM HARPER: Well, one, I
4 guess -- I guess you can say -- well, there's two (2)
5 things. One (1), ideally, it should -- you know,
6 ideally, if you could identify it, if you were that --
7 if -- if you're -- if the GIS system for the utility
8 was -- was that finely tuned and you could identify
9 them, yes.
10 To go to your second question, which I
11 assume -- I do not agree that it would be then -- the
12 fact that it's directly assigned, it's still on the
13 system side of the metre, and therefore it's re -- you
14 know, it would be reasonable to include it in the
15 allocation base because it's on the systems. We have
16 to draw a demarcation point somewhere.
17 MS. DENISE PAMBRUN: Okay. And I
18 understand. In -- in the case of residential, the
19 demarcation point is the metre.
20 MR. WILLIAM HARPER: Yes.
21 MS. DENISE PAMBRUN: The difficulty in
22 the area and roadway lighting category is there's no
23 metre.
24 MR. WILLIAM HARPER: Exactly. And so
25 --

1 MS. DENISE PAMBRUN: And so you have
2 to pick a different de -- demarcation point.
3 MR. WILLIAM HARPER: Yeah.
4 MS. DENISE PAMBRUN: And then I'm
5 suggesting to you is what the demarcation point --
6 well, I'm asking you what you think the demarcation
7 point may have to be.
8 MR. WILLIAM HARPER: Well, I guess
9 there is no equivalent service drop, my understanding
10 is, for -- for streetway lighting. You know, I just
11 got off of a work group on street lighting cost
12 allocation for -- for the OEB, and so -- but there --
13 there is no sort of service drop for street lighting.
14 MS. DENISE PAMBRUN: Right.
15 MR. WILLIAM HARPER: But there are --
16 but there -- there is the issue about sort of what use
17 of the secondary and whether that's on what's viewed
18 as being -- where that is relative to the demarcation
19 point. So I -- I don't -- services for residential
20 may not be a good analogy because there is no
21 equivalent asset for street lighting.
22 MS. DENISE PAMBRUN: Right, but I
23 think it's also a little simplistic to say that the
24 poles and the wires between the poles are not part of
25 the electrical system because you could certainly

1 argue that they are.

2 Isn't that fair?

3 MR. WILLIAM HARPER: Yes. No, and I

4 think I've agreed with you on that point. And I think

5 it -- you know, you've got -- if you say there's an

6 issue here conceptually, then I think you've got --

7 you know, you -- you've got a decision.

8 You know, do you actually want to try

9 and go in? And can you parse out the costs? And is

10 record -- are the records even adequate enough for you

11 to be able to parse out the costs and make a

12 distinction and say, I'm going to apply a 20/80

13 weighting to -- to those? And -- and if the records

14 were sufficient, you could do that.

15 Your next step might be to say, The

16 records aren't sufficient that I feel comfortable

17 putting a percentage to it. But I can tell you that

18 the gross majority of the costs fall in pot A or pot

19 B, in which case I think the simplest approach might -

20 - or the most appropriate approach would be to say,

21 Wherever the -- you know, the vast majority of the

22 dollars fall, that's -- that's the way would be the

23 most reasonable way to treat it.

24 MS. DENISE PAMBRUN: Right. You've

25 heard the comment about the fridges and stoves. Do

1 you agree with Manitoba Hydro that the fridges and
2 stoves analogy is a useful one?
3 MR. WILLIAM HARPER: Well, you know, I
4 think it's -- it -- it's one you can use. Sort of the
5 analogy I was thinking of was, you know, if -- and I'd
6 have to think about it very long. I hate analogies
7 because inevitably somebody ties you up on them.
8 But -- but from a clean energy strategy
9 perspective, there was a view and directive from the
10 government that Manitoba Hydro should be out there
11 subsidizing and basically offering chargers to
12 residential customers to put in their garages to
13 charge electric cars because this was good for the
14 environment, it was consistent with their strategy.
15 And Manitoba Hydro should be financing
16 these, and it would go on their weight base, and, you
17 know, they may charge customers. Like I -- I would
18 have a difficult time saying, Yes, and now that those
19 will be in Manitoba Hydro's rate base, we should be
20 including them in the allocation base for net export
21 revenue.
22 And when I take that analogy, I say
23 that sounds similar to me to a fridge and a stove.
24 MS. DENISE PAMBRUN: Right. All
25 right. And then you heard an exchange between Mr.

1 Todd and Mr. Bowman this morning where Mr. Todd was
2 struggling to take Mr. Bowman's answer and then
3 explain it to me. Were you -- and that's partly
4 because I don't understand a lot of this stuff.
5 MR. WILLIAM HARPER: No. I -- I must
6 admit I -- I recall the exchange. I don't recall
7 precisely what the -- what the topic was. There's
8 been a lot of topics talked about.
9 MS. DENISE PAMBRUN: It had to do with
10 the weighted energy allocator --
11 MR. WILLIAM HARPER: Yes.
12 MS. DENISE PAMBRUN: -- with a demand
13 allocator. And my initial comment to Mr. Bowman was
14 that he was double dipping, and he didn't agree with
15 that. And then Mr. Todd waded in -- weighed in in an
16 -- and challenged Mr. Bowman.
17 I can have Mr. Todd re-ask the question
18 if you require more explanation than that.
19 MR. WILLIAM HARPER: No. I --
20 MS. DENISE PAMBRUN: -- because I'd
21 like your take on that -- on that debate.
22 MR. WILLIAM HARPER: -- I think I
23 recall it now, and I think, if you recall, during my
24 presentation, I did present my -- my specific view on
25 that, and that is that if you've -- you know,

1 admittedly, there -- there may be a difference in the
2 costs of providing energy on the Manitoba Hydro system
3 in different time periods, in which case, if there's a
4 difference in the costs of providing energy, that
5 would be appropriate to include in any allocation of
6 the energy portion of the peak credit method.
7 To the extent you're using -- you're
8 using information that includes capacity
9 considerations as well as ener -- as -- as well as
10 energy cost considerations.
11 And at least up until 2009, if not
12 after that, the view was was that SEP prices included
13 capacity considerations using SEP prices, in my mind,
14 would -- would end up in double dipping if you were
15 applying them to -- to just the energy side of the
16 equation.
17
18 (BRIEF PAUSE)
19
20 MS. DENISE PAMBRUN: Thank you very
21 much, Mr. Harper. Those are all my questions.
22 MR. WILLIAM HARPER: Thank you.
23 THE FACILITATOR: Thank you. We're
24 finally making up a bit of time. Paul, I -- I think
25 we should get going and see how far we can --

1 (BRIEF PAUSE)

2

3 MR. PAUL CHERNICK: You want me to

4 start rather than MIPUG?

5 THE FACILITATOR: Yes. MIPUG was

6 actually going to change places --

7 MR. PAUL CHERNICK: Okay.

8 THE FACILITATOR: -- with the City of

9 Winnipeg. So if we can go until about 5:00, and

10 hopefully break at a convenient time for you.

11 MR. PAUL CHERNICK: Okay. I should be

12 able to get one (1) answer out by then.

13 MR. WILLIAM HARPER: I won't take a

14 slight for that.

15 MR. PAUL CHERNICK: Well, actually, I

16 meant to say get one (1) question out by then, but --

17 MR. WILLIAM HARPER: Okay.

18 MR. PAUL CHERNICK: -- it's already

19 late in the day. Okay. Let me just cue up the

20 beginning of my questions.

21

22 (BRIEF PAUSE)

23

24 CROSS-EXAMINATION BY MR. PAUL CHERNICK:

25 MR. PAUL CHERNICK: On DSM, the

1 allocation of DSM, you take a position that DSM should
2 be treated as a resource and allocated on the basis of
3 its benefits. And you justify that on the grounds
4 that DSM reduces overall costs and benefits all
5 customers.
6 Are you sure that cost-effective DSM,
7 if allocated the way you've proposed, would actually
8 wind up reducing the bill, not just for all customers
9 as a group, but for each customer class? That is, is
10 it possible that the allocation of costs to some class
11 might be greater than the benefits that they receive?
12 MR. WILLIAM HARPER: Given that I am
13 always surprised how cost of service models -- when
14 you run the model at the end of the day, how things
15 turn out. Sometimes I'm surprised with -- with all
16 the puts and takes, how things come out at the end of
17 the day.
18 I can't say unequivocally that -- that
19 a circumstance like -- like what you're stating
20 wouldn't arise.
21 MR. PAUL CHERNICK: Because one (1) of
22 the things that DSM does is that it reduces the cost
23 allocation determinants of the participating class,
24 right?
25 MR. WILLIAM HARPER: Yes.

1 MR. PAUL CHERNICK: So some costs are
2 going to be reallocated to other classes. So the --
3 the share of the cost pie for those other classes will
4 go up as this participating classes share goes down.
5 But if, as you pointed out, the whole pie gets
6 smaller, and we've got those two (2) things going on
7 at once.
8 So I'd just like to suggest to you that
9 maybe it's not as clear that the -- that all classes
10 are necessarily better off due to DSM if it's
11 allocated in proportion to the -- the benefits?
12 MR. WILLIAM HARPER: You know, I'll
13 accept that -- I'll -- I'll accept that may -- may be
14 the case. You know, it depends on -- I think when I
15 was looking at the DSM plan, that the -- for 2012 that
16 underpinned PCOSS14, and I was looking at the various
17 measures that were used. Actually, I -- I believe the
18 plan passed not only the resource cost test, but the
19 utility cost test, but also the RIM test, as well.
20 And so perhaps for that particular
21 plan, you know, it -- it may not be a problem, but I,
22 but -- but I --like I said, I can't guarantee that
23 plan's in -- in the future. But I think, in my mind,
24 the fundamental view is -- the prime test that's used
25 is, like, what's -- what's the overall benefit to the

1 -- does it provide a least cost plan to the system
2 overall and, you know -- and if, on that basis, if --
3 if I have to pick one (1) or the other, I -- I view
4 using it as a system benefit as being the preferable
5 approach.
6 MR. PAUL CHERNICK: And... Okay, so -
7 - so basically what you're saying is you would start
8 there. And it sounds like you're saying, If somebody
9 pointed out that this then caused a problem for some
10 class because of the cost shifting, you'd be willing
11 to rethink your -- your devotion to this particular
12 approach?
13 MR. WILLIAM HARPER: Well, you know,
14 and -- and I think -- I'm not -- I'm not too sure,
15 because I think cost is a -- there may be an issue,
16 and I haven't -- I haven't -- haven't thought this
17 through. This is part of the issues of a workshop, is
18 we're doing this a bit on the fly.
19 But I think there may also be an issue
20 in terms of we're talking about cost shifting for a
21 particular year, or cost shifting over the -- over the
22 overall period where the program is being offered.
23 Because I think we have to remember that while we're
24 doing a cost of service study for one (1) year, we're
25 making investments in whether it be generation or DSM

1 not from the -- not from the perspective of what's
2 going to happen in that one (1) year, but from the
3 perspective of what's going to happen over the long
4 term.
5 And that therefore -- you know, perhaps
6 just because a customer class gets a higher allocation
7 in one (1) particular year may not necessarily mean
8 that if I looked at it over the whole -- over the
9 whole time frame, and con -- cons -- over which the
10 DSM is being considered, if that -- you know, was --
11 was -- would that class be better off in -- in the
12 long run? I think I'd have to con -- consider that as
13 well.
14 That starts to get rather -- brings a
15 lot of con -- considerations into it, but I -- I think
16 it's just more than just short term consideration.
17 MR. PAUL CHERNICK: Okay. You
18 expressed a concern that if -- if costs are allocated
19 back to the participating class, that the -- the
20 customers will have a reduced incentive to
21 participate?
22 MR. WILLIAM HARPER: Well, I -- I
23 think -- I -- I think effectively -- and I -- I mean,
24 the fact that all customers don't participate means
25 that the cost being -- you know, the costs are being -

1 - are being spread over more kilowatt hours and just
2 those customers participating, and therefore it does -
3 - doesn't arise. I think the clearest situation where
4 it arises is within the Curtailable Rate Program that
5 Mr. Bowman mentioned in his evidence where virtually
6 every customer in that class participates in that
7 program.
8 And he was expressing a concern that
9 there were costs of $8 million being allocated and a
10 credit of only $5 million being given to the customers
11 in terms of their discount. And so at -- so he's
12 talking about, Well, let's make the two (2) equal.
13 Well, even if you make the two (2) equal, that means
14 customers have signed up for a lower reliability
15 without any change in their overall financial
16 position.
17 MR. PAUL CHERNICK: But that -- that -
18 - that's different than the Power Smart DSM programs
19 where you're -- you -- in terms of --
20 MR. WILLIAM HARPER: Well, you know, I
21 -- I don't know. If -- if I had a class of customers
22 and for some reason, it was small enough or maybe like
23 area and roadway lighting, you know, I -- I
24 implemented a high efficiency program there, but I
25 charged them in the -- in the cost allocation, and put

1 in their rates effectively the equivalent amount of
2 money that I gave them to go out and undertake the
3 program to begin with, I think you could have a
4 similar problem arise.
5 MR. PAUL CHERNICK: Okay. I -- I see
6 your perspective, there. I was just wondering whether
7 you could explain in the example that you ran where --
8 where you re-allocated the costs, do you understand
9 why it is that the residential allocation rises when
10 you're switching over to allocating the DSM cost
11 primarily on generation, which is energy, and
12 residentials pay a relatively small portion of -- of -
13 - or a relatively small por -- portion of their
14 revenue requirement is for generation and energy
15 compared to, say, the industrial class.
16 MR. WILLIAM HARPER: I -- I think --
17 MR. PAUL CHERNICK: I don't understand
18 what's going on there.
19 MR. WILLIAM HARPER: Well, I think
20 there's a couple of moving parts, here. One (1) has
21 to do with, what's the relative size of the DSM
22 program in residential versus other customer classes.
23 And for other customer classes, such as the GS
24 classes, the dollars being spent on DSM are higher
25 relative to the revenues.

The second piece that's going on there is when you treat it this way, you're allocating -- you're treating it as a generation resource partially to transmission. That's where eighty (80) -- you know, a good -- all -- 93 percent of the costs are going. That ends part -- that ends up being allocated to exports, which will reduce the net export revenues, so that reduces the allocation of net export revenues to -- to certain classes.

Residential is one (1) of the classes that has a -- you know, a significant point of distribution costs in it, and so it gets a -- gets a share of net export revenues and that. So I think it's two (2) things going on. One (1) is -- one (1) is, what's the relative size of the DSM programs for each customer class, and then how does the impact on net export revenues work its way through back -- back to the customer classes?

MR. PAUL CHERNICK: Okay. Moving on to the -- the allocation for -- well, the -- the classification and allocation of generation class, moving off of DSM.

You have a lot of problems with Manitoba Hydro's inclusion of the capacity value in the energy allocator. Is that --

1 MR. WILLIAM HARPER: Well, I -- I
2 think -- like I said, I think there were a lot of
3 reasons in my mind where it did not look like,
4 particularly for the years we were talking about, you
5 know, it -- it was appropriate to -- to incl -- to --
6 to include it, you know.
7 MR. PAUL CHERNICK: Okay. One (1) --
8 one (1) thing that I wanted to ask you about is, I --
9 I wasn't quite sure reading your -- your evidence
10 whether you were getting at this. The cost of the
11 peaker that -- the capacity cost was -- that -- that
12 Manitoba Hydro put into the energy allocation was a
13 cost of a -- a new peaker which -- and it was putting
14 that on top of the short run opportunity sales that
15 are used to -- to price the SEP.
16 So you're comparing -- you're adding in
17 a -- a long-term resource cost with a short-term
18 energy cost. Was that one (1) of the things that you
19 were thinking was a mismatch?
20 MR. WILLIAM HARPER: Well -- well, to
21 clarify, 1) They don't include the cost of the peaker.
22 What they include in there is the cost -- the val --
23 you know, the reference -- the reference value for the
24 discount for their CRP program, which is only a
25 percentage of the cost of a peaker.

1 So I just want to make -- make that
2 clarification explicit.
3 MR. PAUL CHERNICK: Okay. Thank you
4 for that. I was wondering where that specific number
5 came from.
6 MR. WILLIAM HARPER: Yeah, but I -- I
7 think even that dollar value on a per kilowatt per
8 month is considerably higher than the market prices
9 that -- that have been achieved either in the
10 voluntary capacity market or in the subsequent reso --
11 resource market that Manitoba Hydro's been -- been
12 participating in.
13 So if you say it's those two (2)
14 markets and the fact that those two (2) -- people can
15 get some money out of those two (2) markets, which
16 means they don't have to -- when they're making their
17 bids in -- in the -- sort of on the opport -- for --
18 you know, for opportunity sales, at prices quite as
19 high, there -- there is a significant mis -- mismatch
20 there between the value they can get out of those
21 markets and what we're putting in the -- and what
22 we're adding to the SEP-based prices.
23 MR. PAUL CHERNICK: Okay. I -- I
24 wound up not being quite sure what your recommendation
25 was in terms of the capacity adder to the -- to the --

1 the energy allocation across time. I've heard --
2 MR. WILLIAM HARPER: Well -- well, I
3 think, one -- 1) We're dealing here with PCOSS14. And
4 PCOSS14, I think it's -- I think it's clear that based
5 on the -- based on the time frame over which those --
6 you know, the -- you know, the -- over which those
7 prices are -- are averaged in the market that there's
8 isn't -- that we shouldn't be including a capacity
9 adder there.
10 Going for -- go -- going forward, if we
11 -- if -- if you think it's worthwhile, thinking about
12 the issue that may -- maybe I haven't -- maybe the
13 markets now are give -- getting more value to it.
14 Maybe we can understand more why -- why the changes in
15 the PCOSS prices are taking place.
16 Maybe this is something we -- we should
17 be looking at and studying further. But I -- I think
18 for the particular PCOSS14, I think it's premature to
19 add anything in there.
20 MR. PAUL CHERNICK: Okay. So it
21 sounds like you're saying that you're willing to be
22 convinced that some capacity value belongs in the
23 energy allocation --
24 MR. WILLIAM HARPER: Yes.
25 MR. PAUL CHERNICK: -- but you would

1 have to be shown a case that you haven't seen yet?
2 MR. WILLIAM HARPER: Yes. And -- and
3 I think what's particularly curious is the fact that
4 when Manitoba Hydro was asked in the IRs about the,
5 you know, about the change in marketing conditions,
6 they compared prices over fairly broad periods, the
7 MISO definition of periods, which is only four (4)
8 peak-off peak prices, and they showed that there had
9 been a decline in the relative values.
10 Well, that is actually quite
11 diametrically different than what -- when you take the
12 twelve (12) periods and you put peak to off-peak
13 prices there. From the graph I showed you in my
14 presentation, the opposite is going on. So I think
15 one (1) needs -- that goes to not only the fact, you
16 know, do we need it, but what periods are -- are we
17 applying it to, because it seems based on the
18 information we've got to date, that at least on those
19 narrower periods used for the SEP, that the peak-off
20 peak ratios are maintaining historic values if not
21 being higher.
22
23 (BRIEF PAUSE)
24
25 MR. PAUL CHERNICK: Okay. Do we have

1 time to move on to another topic? Yeah, I guess we
2 do.
3 MR. WILLIAM HARPER: There's lots of
4 time.
5 MR. PAUL CHERNICK: Okay. On sub-
6 transmission, the functionalization and allocation of
7 -- of the sub-transmission function, I take it from
8 your -- your evidence that you support Manitoba
9 Hydro's treatment of that set of costs.
10 Is that correct?
11 MR. WILLIAM HARPER: Yes, I do.
12 That's what the -- the evidence outlined, yes.
13 MR. PAUL CHERNICK: So the -- the
14 first part of that is to -- that they break out sub-
15 transmission costs and they say the industrial
16 customers served directly off transmission should not
17 be charged any costs for sub-transmission, but
18 everybody else should be -- should pay for both
19 transmission and sub-transmission.
20 So if the class uses 100 megawatts or
21 however it's being measured, they pay -- if they're
22 the industrial class, they pay for 100 megawatts if --
23 the large -- the high-voltage industrial. And if
24 they're anybody else, they pay for 100 megawatts of --
25 share of the transmission plus 100 megawatts of sub-

1 transmission, which implies that sub-transmission
2 customers are more expensive to serve because they're
3 served at sub-transmission rather than transmission.
4 Is that right?
5 MR. WILLIAM HARPER: Yes.
6 MR. PAUL CHERNICK: Do you think
7 that's true factually that it would be cheaper to run
8 transmission lines out to the --
9 MR. WILLIAM HARPER: Well, I must
10 admit, when you asked me the question, I qualified it
11 by saying, That's -- that's the position I outlined in
12 my evidence, you know.
13 MR. PAUL CHERNICK: You're a sneaky
14 one, aren't you?
15 MR. WILLIAM HARPER: No, no. You
16 know, and because to be -- to be -- be quite honest
17 with you, and you'll find this out tomorrow, I read
18 with quite an amount of interest your -- your evidence
19 and your -- and your arguments. And I think that's an
20 area where -- where there's worth -- worth exploring.
21 I mean, I don't -- I haven't thought
22 about the paradigm exactly the way you'd set -- you --
23 you set it out in your evidence. It is -- it is
24 somewhat different than the normal paradigm that's
25 sort of applied in -- in the industry, but I think

1 it's a -- I think it's an intriguing one, if I -- if I
2 can describe it that way.
3 And I think it perhaps requires a
4 little bit more numerical investigation. I mean, you
5 were talking about how much of the distribution system
6 really doesn't use transmission, it uses sub-
7 transmission. I'd be interested in getting it.
8 And you were trying to come up with
9 some estimates. I'd be interested in getting a take
10 from Manitoba Hydro in terms of whether that's a
11 minority of the case or -- you seem to be suggesting
12 it was a fair significant part of the case sort of
13 thing.
14 So I think that -- I think that is an
15 area that's -- that -- that's worth -- that's worth
16 exploring. I think it puts the paradi -- like I said,
17 it uses a somewhat different paradigm, and it's
18 something that takes more than five (5) minutes for
19 someone to wrap one's mind around.
20 MR. PAUL CHERNICK: Well, it's
21 refreshing in a regulatory process to have somebody
22 say that they want to think about it, and they
23 actually seem to mean it.
24 The -- the other sub-transmission issue
25 is -- is the allocator, the choice of coincident

1 versus non-coincident peak, or some kind of more
2 complex coincident peak like the one that's used for -
3 - for transmission.
4 Do you have any thought about whether
5 Hydro's non-coincident peak is -- is a superior
6 allocator than -- than a coincident peak measure of
7 some sort?
8 MR. WILLIAM HARPER: Well, I think --
9 and -- and again, sort of, you know, we're working
10 with sort of a minimum amount of information. But --
11 but I think -- I think the problem is -- is that
12 probably for those lines, coincident peak is probably
13 -- like if you were to look at -- let's take -- take
14 the presumption that, if we looked at where those
15 lines -- what were the -- where were the peaks on each
16 of those lines?
17 And you assume that, because they're
18 serving different types of customers in different
19 locations, the peaks are all over -- all over the
20 place. The -- you know, the -- the graph for those
21 peaks may look something like the graph you have in
22 your own evidence for sub-transmission stations.
23 They're all over the place.
24 On the one hand, you can make the
25 argument that that doesn't support an NCP allocation

1 because they're not peaking at the time of individual
2 customer class.
3 You can take that same argument and
4 turn it on its head and say, Well, they're not peaking
5 coincident with the system peak, and therefore a
6 coincident peak allocation isn't appropriate either,
7 you know.
8 And so that you're left with, well, the
9 two (2) most standard forms of allocation we use,
10 we've just concluded neither of them is sort of the
11 perfect fit for this situation.
12 In -- in those cases where there's a
13 lot of dispersion in the load, I would tend to lean
14 towards the non -- non-coincident peak allocation
15 myself.
16 MR. PAUL CHERNICK: Well, wouldn't it
17 also be feasible to --
18 MR. WILLIAM HARPER: Oh --
19 MR. PAUL CHERNICK: -- drive an
20 allocator specifically for the sub-transmission --
21 MR. WILLIAM HARPER: -- oh, oh, you
22 know --
23 MR. PAUL CHERNICK: -- reflecting the
24 hours it has high load?
25 MR. WILLIAM HARPER: I -- I think --

1 I think in your evidence outlined the perfect world,
2 where if we knew the -- if we knew the customer loads
3 and how they were on each individual line we could --
4 you know, we could -- we could come up with, but we
5 don't have that -- that level of information. And I
6 think what we're dealing with here is information at
7 an aggregate level.
8 So, you know, in an ideal world we
9 might try and define an amount of information we would
10 need to do that. To be honest with you, I'm sure
11 Manitoba Hydro wouldn't readily have such information
12 available and we'd be dealing with, well, at a
13 minimum, what are we going to do for the next five (5)
14 to eight (8) years.
15 MR. PAUL CHERNICK: Okay, well, let's
16 -- let's step back from the ideal world that we would
17 like to live in and look at the -- the real world.
18 Manitoba Hydro does have estimates of hourly load by -
19 - by rate class, right? And we know which of those
20 rate classes are served, at least in part, off of the
21 subtransmission system.
22 So your point is, well, we don't know
23 exactly for the subtransmission system as a whole or -
24 - or any one (1) line what percentage of that is -- is
25 GSL 30:70 and what part is GSM and what part is -- is

1 residential.

2 But if you just assume that the mix on

3 the subtransmission system was the same as on the

4 system as a whole, which is what you're doing with the

5 transmission lines, wou -- would that be a reasonable

6 way of approaching the --

7 MR. WILLIAM HARPER: Well -- well,

8 except the problem is, is we -- we've already accepted

9 that the peaks for those lines are all over the place,

10 so that -- that proposition doesn't hold.

11 MR. PAUL CHERNICK: And is that not

12 true for the transmission system?

13 MR. WILLIAM HARPER: Well, probably

14 to a lesser extent. You know, yes, there's probably

15 peaks at particularly different points on some

16 transmissions, but I -- I would suspect that they're

17 much closely group -- grouped together, you know. And

18 that's part -- part of the reason, to some extent, why

19 you're using, not one (1) single hour, but multiple

20 hours for -- for your CP allocators.

21 MR. PAUL CHERNICK: Okay. So, well, I

22 -- so I think the one (1) thing that maybe we can

23 agree on on that subject of -- of how to allocate the

24 subtransmission cost is that it would be nice to see

25 what data Manitoba Hydro could come up with and to --

1 to think about it some more.

2 MR. WILLIAM HARPER: Yeah. This --

3 this is one (1) of those area where if -- you know, if

4 we'd had some working groups a year go dealing with

5 subtransmission and distribution we might have been

6 able to explore those a little bit further at that

7 point in time, you know, but -- but we are where we

8 are today.

9 MR. PAUL CHERNICK: But we could be

10 someplace else in the future?

11 MR. WILLIAM HARPER: Yes.

12 MR. PAUL CHERNICK: Okay. Speaking of

13 Manitoba Hydro's date, you say in your testimony, page

14 78 I think it is, that the SCC data available from

15 Hydro's financial systems regarding various

16 distribution equipment is sufficiently detailed to

17 facilitate subfunctionalization. And you -- you're

18 saying that, as I understand it, in the context of, I

19 believe, the primary secondary?

20 MR. WILLIAM HARPER: No, I'm saying

21 that in the context of substations versus poles ans

22 wires versus services --

23 MR. PAUL CHERNICK: Okay --

24 MR. WILLIAM HARPER: -- versus

25 transformers.

1 MR. PAUL CHERNICK: -- for -- for that
2 level.
3 MR. WILLIAM HARPER: The
4 subfunctionalization that they actually have
5 implemented.
6 MR. PAUL CHERNICK: Okay. Oh, okay.
7 So you're saying they have the data to do what they've
8 done?
9 MR. WILLIAM HARPER: Yes, they had the
10 data to do what they've done.
11 MR. PAUL CHERNICK: Okay.
12 MR. WILLIAM HARPER: And that's why
13 sort of, you know -- and that's why sort of the
14 subfunctionalization, at least for those particular
15 costs, is -- seems -- seems totally reasonable to me
16 because -- because they've got the information in
17 their financial systems. There -- there is virtually
18 no allocation involved in ter -- terms with the
19 physical asset costs.
20 There is some allocation in some of the
21 overheads.
22 MR. PAUL CHERNICK: Yes. Okay.
23 MR. WILLIAM HARPER: They have some
24 problems there.
25 MR. PAUL CHERNICK: All right. I -- I

1 thought that that was -- that was about the --
2 determining the -- either the demand customer split or
3 the -- the primary secondary split. And -- but when
4 it comes to those kinds of issues, there's -- the --
5 the company has a lot less useful data?
6 MR. WILLIAM HARPER: Yes. And I -- I
7 think, you know, that was on page 77. You know, I was
8 -- you know -- you know. And I think for the evidence
9 I've talked about, the fact that, you know -- well,
10 page 77, in the middle paragraph there, it says:
11 "It will be prudent for Manitoba
12 Hydro to investigate ways of
13 updating their percentage split for
14 secondary costs."
15 And I left it that prudent update
16 because I'm not too sure what information they have
17 and what information they can bring to bear on that
18 particular question.
19 MR. PAUL CHERNICK: Okay. And -- and
20 in that same section you were -- you expressed some
21 concern about the functionalization of common costs
22 among the distribution subfunctions.
23 And I -- I just wonder whether you
24 could --
25 MR. WILLIAM HARPER: Right. Well --

1 MR. PAUL CHERNICK: -- run -- run
2 through that again because I didn't quite follow the
3 issue.
4 MR. WILLIAM HARPER: And maybe I can
5 make a distinction. On the financial records they --
6 they track the -- you know, the assets, the
7 transformers --
8 MR. PAUL CHERNICK: Right.
9 MR. WILLIAM HARPER: -- the poles, the
10 wires, the services, that's fine. There were also a
11 number of -- I guess when we -- when you use the term
12 SCC, that's settlement cost centers in their financial
13 systems, where they track more general cost for
14 distribution overall related to things like research
15 and development, environment and hazardous waste,
16 planning records, those -- those types -- you know, I
17 typically view those as sort of like the overheads
18 that sort of support the whole activity.
19 MR. PAUL CHERNICK: Right.
20 MR. WILLIAM HARPER: But what they've
21 done with those is they've taken all those costs, and
22 I believe they've put them just in the distribution
23 station sub -- subfunction, and -- as opposed to
24 thinking through and saying that maybe some of those
25 costs support some of the other subfunctions as well,

1 and we should have allocated them to some of those
2 other subfunctions.
3
4 (BRIEF PAUSE)
5
6 MR. PAUL CHERNICK: You just said to
7 the -- they allocate them all to the...
8 MR. WILLIAM HARPER: Distribution
9 substation subfunction that --
10 MR. PAUL CHERNICK: Substations -- at
11 the top of page 78 you say that:
12 "The communication building and
13 general equipment have all been
14 subfunctionalized as poles and
15 wires."
16 MR. WILLIAM HARPER: That's a
17 different category of costs again.
18 MR. PAUL CHERNICK: Okay. So some
19 things they put entirely on poles and wires. Some
20 things they put entirely on stations.
21 MR. WILLIAM HARPER: Right. And I
22 guess again it was a matter of, you know -- you know,
23 it's all going somewhere. Sort of if one was to step
24 back and look at it on a -- sort of on a broader basis
25 one might be able to come up with a more consistent

1 approach to how you're allocating all of those things.
2 MR. PAUL CHERNICK: Okay. So that's
3 another thing that would be nice to know better in the
4 future.
5 MR. WILLIAM HARPER: Yeah, and I guess
6 it -- it seems to me one way of doing that would be to
7 -- a lot of the reason why they're doing this is a lot
8 of this subfunction -- a lot of this functionalization
9 cost is outside of their model, so that the costs
10 really can't -- there is -- really isn't as readily
11 allocated as if some of these costs were actually
12 incorporated and allocated within the model. That's
13 one of the model recommendations that -- that I've
14 been making.
15 MR. PAUL CHERNICK: Okay. Because
16 it's easier if you have the communications building
17 and general equipment that you've functionalized to
18 distribution, it's easier just stick it in one (1)
19 line item rather than spreading it out over --
20 MR. WILLIAM HARPER: Yeah.
21 MR. PAUL CHERNICK: -- all six (6) or
22 eight (8).
23 MR. WILLIAM HARPER: Yeah.
24 MR. PAUL CHERNICK: Okay.
25

1 (BRIEF PAUSE)

2

3 MR. PAUL CHERNICK: Moving onto -- to
4 the exciting topic of the allocation of service drops,
5 the -- you discuss the number of res -- of multi
6 family buildings that Manitoba Hydro serves where
7 customers are individually metered within them. And
8 there also tend to be GSS and/or GSM customers in
9 those same buildings.
10 I assume that's either for the
11 buildings own load, the offices, maybe there's --
12 there's store on the first floor or something --
13 MR. WILLIAM HARPER: Well, I would
14 think and my understanding is -- subject -- subject to
15 correction, is that what you're probably talking about
16 is things like apartment buildings whereby as well as
17 the individual residential units in the apartment that
18 are individually metered you also have the apartment
19 owner itself who's taking power probably at some
20 general service rate in order to power the lights in
21 the halls, power the elevators, power the fans and the
22 furnaces that are heating the building, you know, so
23 that at that general level that's -- that's the
24 general service cust -- customer.
25 And then you have the -- you know,

1 which is -- I would probably think would be typically
2 the -- you know, could well be the -- the building
3 owner.
4 MR. PAUL CHERNICK: Okay. So I'm
5 trying to understand your calculation on page -- that
6 you describe on page 79, and you then have a table on
7 page 80 implementing it. And -- and not -- I
8 understand the calculation. I'm just trying to
9 understand the rationale.
10 So there are a hundred and three
11 thousand (103,000) multi family buildings metered in -
12 - in the way we've been talking about. And -- excuse
13 me, one hundred (100) -- a hundred and three thousand
14 (103,000) customers. We don't know how many buildings
15 there are.
16 MR. WILLIAM HARPER: Well, you know,
17 from my understanding there's -- like these hundred
18 and three thousand (103,000) customers are in -- are -
19 - are associated with forty-nine (4,900) general
20 service -- small or general service medium.
21 So I assume there's probably something
22 in the order of forty-nine hundred (4,900) buildings
23 we're talking about in total if, you know, if -- if
24 there's one (1) general service --
25 MR. PAUL CHERNICK: Right. Or it

1 could be fewer buildings, because there's the account
2 for the -- for the hallways, and so on, but there's
3 another account for the drycleaner who has a -- an
4 operation in the basement, or all kinds of other
5 things.
6 MR. WILLIAM HARPER: That, you know...
7 MR. PAUL CHERNICK: So you say, Okay,
8 we've got a hundred and thirty thousand (130,000)
9 residential customers, forty-nine hundred (4,900) GS
10 or GSM customers in those buildings, however many
11 buildings there are, and you're basically assuming
12 there are probably about forty-nine hundred (4,900) of
13 them?
14 MR. WILLIAM HARPER: Yes.
15 MR. PAUL CHERNICK: Okay. And then
16 you say, We're going to reduce the number of GSS
17 services by twelve thousand six hundred and fifty-nine
18 (12,659). That's in your Table 16?
19 MR. WILLIAM HARPER: Yes.
20 MR. PAUL CHERNICK: But there are only
21 forty-nine hundred (4,900) GSS and GSM customers put
22 together in these buildings.
23 MR. WILLIAM HARPER: Yes.
24 MR. PAUL CHERNICK: So how are you
25 getting such a large reduction in -- in the number of

1 --

2 MR. WILLIAM HARPER: Well, I guess

3 when I noted the fact that we had a hundred and three

4 thousand (103,000) too many services in total in the

5 allocation I was looking at -- there -- there are a

6 number of ways you could do it.

7 One (1) way would be to say, Well, each

8 of those has got a general service meter. Why don't

9 we just reduce residential by a hundred and three

10 thousand (103,000). That would clearly give the most

11 benefit. That gives all of the benefit of the change

12 to -- to the residential customers.

13 And I was struggling with the fact, but

14 that one (1) -- is one (1) realistic way -- way of

15 doing it. We don't know how many -- we don't know how

16 many of these buildings are GSS or GSM and that's why

17 I used the percentage splits for total.

18 If we knew how many of the buildings

19 were exactly GSS or GSM, you -- you could -- you could

20 use that -- you could use those numbers instead. They

21 would probably be -- be preferable to what I've done

22 here.

23 I was just trying to go through and

24 come up with -- with an illustrative calculation of

25 the fact we've got a hundred and three thousand

1 (103,000) too many. I was coming up with what would
2 be sort of a modest way of -- of reducing -- of
3 reducing it by applying it sort of equally across all
4 of the customer classes and showing -- and trying to
5 figure out what the impact would be.
6 Clearly there would more favourable
7 impacts particularly on the residential class than if
8 you were to do it another way. And -- and I -- I
9 fully agree with you, with more information --
10 MR. PAUL CHERNICK: Right.
11 MR. WILLIAM HARPER: -- it's probably
12 more appropriate to do it another way.
13 MR. PAUL CHERNICK: I -- I'm always in
14 favour of more information. But in this particular
15 case, I -- I just think your result doesn't make sense
16 --
17 MR. WILLIAM HARPER: Yeah.
18 MR. PAUL CHERNICK: -- that you can't
19 reduce the number of GSS and GSM customers by more
20 than the total of who are in the building. So you've
21 got a hundred and three thousand (103,000) extra
22 customers. You've got a hundred a three thousand
23 (103,000) more customers than you have service lines
24 to this building under your assumptions.
25 MR. WILLIAM HARPER: Yeah.

1 MR. PAUL CHERNICK: So it seems like
2 you could then split those between residential and the
3 commercial using the hundred and three thousand
4 (103,000) residential and the forty-nine hundred
5 (4,900) commercial and use that to make a ratio and
6 then take the commercial share and split it using the
7 total number of GSS and GSM.
8 MR. WILLIAM HARPER: I mean, that
9 probably would have been a bet -- would have been a
10 better way to do it. I -- I would agree with you.
11 MR. PAUL CHERNICK: Okay. Good.
12 That's -- that also indicates I also understood what
13 you were doing, which is a great relief. I believe
14 that's all my questions.
15 THE FACILITATOR: Perfect. We're
16 finishing on time in -- in spite of all our gyrations
17 during the day. So thank you very much, everyone.
18 And I think today's stuff has really brought out a lot
19 of information on the key issues.
20 So tomorrow at nine o'clock we'll have
21 more fun. Thanks.
22
23 --- Upon adjourning at 4:59 p.m.
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25

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3 Certified correct,
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7 _____
8 Sean Coleman, Mr.
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