EXHIBIT MIPUG-10-1

Index – MIPUG Book of Documents

2015/16 Manitoba Hydro GRA

As of May 26, 2015

Tab	Description	Reference
Manitoba Hydro Policy Panel		
1	A) DSM Financial Evaluation for three rate setting methodologies: Main Submission Rate Methodology, Alternative Rate Methodology 1 and Alternative Rate Methodology 2. B) Sunk costs by project (Conawapa, Keeyask and US Tie Line) over 18 year amortization period to 2033 – included in select rate increases in NFAT.	A) Exhibit MH-104-12 from the NFAT Review B) MIPUG/MH I-003c from the NFAT Review
2	A) Comparison of the capital spending differences between CEF14 and NFAT	A) PUB/MH I-13 from 2015/16 GRA
3	A) Manitoba Hydro 2012/13 & 2013/14 GRA – Transcript from December 10, 2012	A) Opening Remarks of Scott Thomson and Cross-Exam on December 10, 2012; pages 297- 326, 377 – 385, and 391 – 393.

TAB 1

NFAT DSM ANALYSIS - MAIN SUBMISSION RATE METHODOLOGY

	Development Plan	Plan #	DSM Level	Keeyask & Conawapa Capital Cost Scenario	(A) Cumulative Nominal Rate Increases by 2061/62 - Compared to Base	(B) Projected Even-Annual Rate Increases (2015/16 to 2031/32)	(C) Equivalent Even-Annual Rate Increases over the Forecast Period (2014/15 to 2061/62)	(D) Cumulative Nominal Rate Increases as at 2031/32	(E) Cumulative Nominal Rate Increases as at 2061/62	(F) Net Fixed Assets	(G) Net Debt	(H) Retained Earnings	(I) Debt:Equity Ratio as at 2031/32	(J) Net Fixed Assets	(K) Net Debt	(L) Retained Earnings	(M) Debt:Equity Ratio as at 2061/62	(N) * 20 year Present Value of Consumers Revenue (2031/32 back to 2012/13) in Billions of 2012PV$	(O) * 50 year Present Value of Consumers Revenue (2061/62 back to 2012/13) in Billions of 2012PV$	(P) * 50 year Present Value of Consumers Revenue - Compared to Base in Billions of 2012PV$
										As at 2031/32 in Billions of Nominal Dollars				As at 2061/62 in Billions of Nominal Dollars						
1	K19 Sales C26 750 MW	14	Base	Reference	-	4.33%	1.42%	114%	96%	$34.7	$25.2	$8.4	75%	$37.7	$15.0	$16.8	47%	$30.8	$60.6	-
2	K19 Sales C30 750 MW	14	DSM Level 1	Reference	-4%	4.29%	1.37%	112%	92%	$36.8	$26.9	$9.0	75%	$38.7	$15.2	$17.6	46%	$30.1	$58.6	($1.9)
3	K19 Sales C31 750 MW	14	DSM Level 2	Reference	-10%	4.27%	1.30%	112%	86%	$36.9	$26.9	$9.0	75%	$39.1	$15.4	$17.8	46%	$29.3	$56.5	($4.0)
4	K19 Sales C33 750 MW	14	DSM Level 3	Reference	-10%	4.39%	1.31%	116%	87%	$34.4	$25.2	$8.4	75%	$40.0	$16.3	$17.7	48%	$29.3	$56.5	($4.0)
5	K19 Gas 750 MW	5	Base	Reference	-	3.63%	1.85%	91%	141%	$25.3	$18.5	$6.2	75%	$33.8	$15.3	$13.0	54%	$29.2	$61.4	-
6	K19 Gas 750 MW	5	DSM Level 1	Reference	-7%	3.76%	1.79%	95%	135%	$25.1	$18.3	$6.1	75%	$33.5	$15.1	$12.9	54%	$28.9	$58.7	($2.7)
7	K19 Gas 750 MW	5	DSM Level 2	Reference	-15%	3.74%	1.72%	94%	126%	$24.7	$18.1	$6.0	75%	$32.7	$14.6	$12.7	53%	$28.2	$56.2	($5.1)
8	K19 Gas 750 MW	5	DSM Level 3	Reference	-19%	4.04%	1.68%	104%	122%	$24.6	$18.0	$6.0	75%	$32.4	$14.2	$12.7	53%	$28.5	$55.9	($5.5)
9	All Gas	1	Base	Reference	-	3.29%	2.14%	80%	176%	$20.2	$14.8	$4.9	75%	$31.8	$15.6	$11.0	59%	$28.4	$62.8	-
10	All Gas	1	DSM Level 1	Reference	-11%	3.40%	2.05%	84%	165%	$19.3	$14.2	$4.7	75%	$30.4	$14.5	$10.7	57%	$28.1	$60.0	($2.7)
11	All Gas	1	DSM Level 2	Reference	-15%	3.36%	2.02%	82%	161%	$19.0	$13.9	$4.6	75%	$29.9	$14.2	$10.5	57%	$27.4	$57.8	($5.0)
12	All Gas	1	DSM Level 3	Reference	-19%	3.65%	1.99%	91%	157%	$18.9	$13.9	$4.6	75%	$29.7	$14.0	$10.5	57%	$27.7	$57.4	($5.4)
13	K19 Sales C26 750 MW	14	Base	High	-	4.81%	1.45%	131%	100%	$37.3	$27.2	$9.1	75%	$39.0	$15.3	$17.9	46%	$32.0	$63.1	-
14	K19 Sales C30 750 MW	14	DSM Level 1	High	-3%	4.68%	1.42%	126%	97%	$39.8	$29.1	$9.7	75%	$40.4	$15.6	$18.9	45%	$31.0	$61.0	($2.0)
15	K19 Sales C31 750 MW	14	DSM Level 2	High	-9%	4.63%	1.35%	125%	91%	$39.9	$29.2	$9.8	75%	$40.9	$15.8	$19.1	45%	$30.2	$58.9	($4.2)
16	K19 Sales C33 750 MW	14	DSM Level 3	High	-7%	4.72%	1.38%	128%	93%	$36.8	$27.0	$9.0	75%	$41.9	$16.9	$19.0	47%	$30.0	$58.9	($4.2)
17	K19 Gas 750 MW	5	Base	High	-	3.87%	1.86%	98%	142%	$26.0	$19.0	$6.3	75%	$34.2	$15.3	$13.3	53%	$29.7	$62.3	-
18	K19 Gas 750 MW	5	DSM Level 1	High	-7%	4.01%	1.80%	103%	135%	$25.8	$18.8	$6.3	75%	$33.8	$15.1	$13.2	53%	$29.4	$59.6	($2.7)
19	K19 Gas 750 MW	5	DSM Level 2	High	-15%	3.99%	1.72%	102%	127%	$25.4	$18.6	$6.2	75%	$33.1	$14.7	$13.0	53%	$28.7	$57.1	($5.2)
20	K19 Gas 750 MW	5	DSM Level 3	High	-19%	4.29%	1.69%	112%	123%	$25.3	$18.5	$6.2	75%	$32.7	$14.3	$12.9	52%	$29.1	$56.8	($5.5)

* 2012 Constant dollar Consumers' Revenue discounted at 1.86% real discount rate

NFAT DSM ANALYSIS - ALTERNATIVE RATE METHODOLOGY 1

	Development Plan	Plan #	DSM Level	Keeyask & Conawapa Capital Cost Scenario	(A) Cumulative Nominal Rate Increases by 2061/62 - Compared to Base	(B) Year that 1.20 Interest Coverage Ratio is Achieved	(C) Equivalent Even-Annual Rate Increases over the Forecast Period (2014/15 to 2061/62)	(D) Cumulative Nominal Rate Increases as at 2031/32	(E) Cumulative Nominal Rate Increases as at 2061/62	(F) Net Fixed Assets	(G) Net Debt	(H) Retained Earnings	(I) Debt:Equity Ratio as at 2031/32	(J) Net Fixed Assets	(K) Net Debt	(L) Retained Earnings	(M) Debt:Equity Ratio as at 2061/62	(N) * 20 year Present Value of Consumers Revenue (2031/32 back to 2012/13) in Billions of 2012PV$	(O) * 50 year Present Value of Consumers Revenue (2061/62 back to 2012/13) in Billions of 2012PV$	(P) * 50 year Present Value of Consumers Revenue - Compared to Base in Billions of 2012PV$
										As at 2031/32 in Billions of Nominal Dollars				As at 2061/62 in Billions of Nominal Dollars						
21	K19 Sales C26 750 MW	14	Base	Reference	-	2027	1.50%	78%	104%	$34.7	$28.2	$5.4	84%	$37.7	$17.0	$14.7	53%	$29.5	$61.0	-
22	K19 Sales C30 750 MW	14	DSM Level 1	Reference	-2%	2027	1.48%	76%	102%	$36.8	$30.6	$5.2	86%	$38.7	$17.7	$15.1	54%	$28.5	$59.2	($1.8)
23	K19 Sales C31 750 MW	14	DSM Level 2	Reference	-8%	2027	1.42%	70%	96%	$36.9	$30.9	$5.1	86%	$39.1	$18.0	$15.1	54%	$27.6	$57.1	($3.9)
24	K19 Sales C33 750 MW	14	DSM Level 3	Reference	-6%	2027	1.44%	72%	98%	$34.4	$29.3	$4.3	87%	$40.0	$19.0	$14.9	56%	$27.5	$57.1	($3.8)
25	K19 Gas 750 MW	5	Base	Reference	-	2025	1.89%	61%	146%	$25.3	$20.1	$4.5	82%	$33.8	$16.4	$11.9	58%	$28.4	$61.5	-
26	K19 Gas 750 MW	5	DSM Level 1	Reference	-6%	2026	1.84%	61%	140%	$25.1	$20.3	$4.1	83%	$33.5	$16.4	$11.5	59%	$27.9	$58.9	($2.6)
27	K19 Gas 750 MW	5	DSM Level 2	Reference	-14%	2027	1.77%	56%	132%	$24.7	$20.1	$4.0	83%	$32.7	$15.9	$11.3	58%	$27.2	$56.4	($5.1)
28	K19 Gas 750 MW	5	DSM Level 3	Reference	-16%	2027	1.75%	61%	130%	$24.6	$20.6	$3.4	86%	$32.4	$16.0	$10.9	59%	$27.3	$56.2	($5.3)
29	All Gas	1	Base	Reference	-	2023	2.16%	57%	179%	$20.2	$15.9	$3.8	81%	$31.8	$16.3	$10.2	61%	$27.8	$62.8	-
30	All Gas	1	DSM Level 1	Reference	-10%	2024	2.08%	58%	168%	$19.3	$15.4	$3.5	81%	$30.4	$15.2	$9.9	60%	$27.5	$60.1	($2.7)
31	All Gas	1	DSM Level 2	Reference	-15%	2024	2.04%	54%	164%	$19.0	$15.1	$3.5	81%	$29.9	$14.9	$9.7	60%	$26.8	$57.8	($5.0)
32	All Gas	1	DSM Level 3	Reference	-18%	2025	2.02%	56%	161%	$18.9	$15.4	$3.1	83%	$29.7	$15.0	$9.5	61%	$26.9	$57.5	($5.3)
33	K19 Sales C26 750 MW	14	Base	High	-	2032	1.59%	100%	113%	$37.3	$32.2	$4.0	89%	$39.0	$18.6	$14.4	56%	$29.9	$63.8	-
34	K19 Sales C30 750 MW	14	DSM Level 1	High	-4%	2028	1.55%	93%	110%	$39.8	$34.0	$4.9	88%	$40.4	$18.8	$15.6	55%	$29.0	$61.8	($2.1)
35	K19 Sales C31 750 MW	14	DSM Level 2	High	-9%	2027	1.50%	82%	104%	$39.9	$34.2	$4.8	88%	$40.9	$19.2	$15.8	55%	$28.1	$59.7	($4.2)
36	K19 Sales C33 750 MW	14	DSM Level 3	High	-6%	2028	1.53%	81%	107%	$36.8	$32.1	$3.9	89%	$41.9	$20.3	$15.5	57%	$27.9	$59.7	($4.2)
37	K19 Gas 750 MW	5	Base	High	-	2026	1.91%	67%	147%	$26.0	$21.1	$4.2	83%	$34.2	$16.7	$11.9	58%	$28.8	$62.5	-
38	K19 Gas 750 MW	5	DSM Level 1	High	-5%	2027	1.86%	68%	142%	$25.8	$21.4	$3.7	85%	$33.8	$16.8	$11.4	59%	$28.3	$59.9	($2.6)
39	K19 Gas 750 MW	5	DSM Level 2	High	-13%	2027	1.79%	62%	134%	$25.4	$21.1	$3.6	85%	$33.1	$16.3	$11.2	59%	$27.5	$57.4	($5.1)
40	K19 Gas 750 MW	5	DSM Level 3	High	-15%	2028	1.78%	68%	133%	$25.3	$21.8	$2.9	88%	$32.7	$16.4	$10.7	60%	$27.6	$57.2	($5.3)

* 2012 Constant dollar Consumers' Revenue discounted at 1.86% real discount rate

NFAT DSM ANALYSIS - ALTERNATIVE RATE METHODOLOGY 2

	Development Plan	Plan #	DSM Level	Keeyask & Conawapa Capital Cost Scenario	(A) Cumulative Nominal Rate Increases by 2061/62 - Compared to Base	(B) Even Annual Rate Increases required to minimize Net Losses between the period as stated below	(C) Equivalent Even-Annual Rate Increases over the Forecast Period (2014/15 to 2061/62)	(D) Cumulative Nominal Rate Increases as at 2031/32	(E) Cumulative Nominal Rate Increases as at 2061/62	(F) Net Fixed Assets	(G) Net Debt	(H) Retained Earnings	(I) Debt:Equity Ratio as at 2031/32	(J) Net Fixed Assets	(K) Net Debt	(L) Retained Earnings	(M) Debt:Equity Ratio as at 2061/62	(N) * 20 year Present Value of Consumers Revenue (2031/32 back to 2012/13) in Billions of 2012PV$	(O) * 50 year Present Value of Consumers Revenue (2061/62 back to 2012/13) in Billions of 2012PV$	(P) * 50 year Present Value of Consumers Revenue - Compared to Base in Billions of 2012PV$
										As at 2031/32 in Billions of Nominal Dollars				As at 2061/62 in Billions of Nominal Dollars						
						2018-2022														
41	K19 Sales C26 750 MW	14	Base	Reference	-	3.95%	1.50%	78%	104%	$34.7	$28.2	$5.4	84%	$37.7	$17.0	$14.7	53%	$29.5	$61.0	-
42	K19 Sales C30 750 MW	14	DSM Level 1	Reference	-2%	4.18%	1.47%	75%	102%	$36.8	$30.4	$5.4	85%	$38.7	$17.5	$15.2	53%	$28.5	$59.1	($1.8)
43	K19 Sales C31 750 MW	14	DSM Level 2	Reference	-8%	4.32%	1.41%	69%	96%	$36.9	$30.6	$5.3	85%	$39.1	$17.8	$15.3	54%	$27.7	$57.0	($4.0)
44	K19 Sales C33 750 MW	14	DSM Level 3	Reference	-8%	5.13%	1.41%	68%	96%	$34.4	$28.4	$5.2	85%	$40.0	$18.5	$15.5	54%	$27.8	$56.9	($4.1)
						2016-2022														
45	K19 Gas 750 MW	5	Base	Reference	-	4.16%	1.89%	60%	145%	$25.3	$19.9	$4.7	81%	$33.8	$16.3	$12.0	57%	$28.4	$61.5	-
46	K19 Gas 750 MW	5	DSM Level 1	Reference	-7%	4.54%	1.83%	59%	138%	$25.1	$19.7	$4.7	81%	$33.5	$16.0	$11.9	57%	$28.1	$58.8	($2.7)
47	K19 Gas 750 MW	5	DSM Level 2	Reference	-15%	4.60%	1.75%	53%	130%	$24.7	$19.4	$4.7	81%	$32.7	$15.5	$11.8	57%	$27.4	$56.2	($5.2)
48	K19 Gas 750 MW	5	DSM Level 3	Reference	-19%	5.08%	1.72%	54%	126%	$24.6	$19.4	$4.7	81%	$32.4	$15.1	$11.7	56%	$27.7	$55.9	($5.6)
						2016 - 2020														
49	All Gas	1	Base	Reference	-	4.95%	2.15%	55%	178%	$20.2	$15.5	$4.2	79%	$31.8	$16.1	$10.5	60%	$27.9	$62.7	$0.0
50	All Gas	1	DSM Level 1	Reference	-11%	5.35%	2.07%	55%	167%	$19.3	$14.8	$4.1	78%	$30.4	$14.9	$10.3	59%	$27.7	$59.9	($2.8)
51	All Gas	1	DSM Level 2	Reference	-16%	5.46%	2.02%	51%	162%	$19.0	$14.5	$4.1	78%	$29.9	$14.5	$10.2	59%	$26.9	$57.6	($5.1)
52	All Gas	1	DSM Level 3	Reference	-20%	5.94%	2.00%	51%	158%	$18.9	$14.4	$4.1	78%	$29.7	$14.3	$10.2	58%	$27.2	$57.2	($5.5)
						2018-2022														
53	K19 Sales C26 750 MW	14	Base	High	0%	4.42%	1.56%	95%	110%	$37.3	$31.3	$5.0	86%	$39.0	$18.0	$15.1	54%	$30.3	$63.7	-
54	K19 Sales C30 750 MW	14	DSM Level 1	High	-2%	4.62%	1.54%	90%	108%	$39.8	$33.4	$5.5	86%	$40.4	$18.4	$16.0	53%	$29.2	$61.6	($2.0)
55	K19 Sales C31 750 MW	14	DSM Level 2	High	-8%	4.75%	1.48%	79%	103%	$39.9	$33.5	$5.4	86%	$40.9	$18.7	$16.2	53%	$28.3	$59.5	($4.2)
56	K19 Sales C33 750 MW	14	DSM Level 3	High	-7%	5.58%	1.49%	74%	103%	$36.8	$30.8	$5.3	85%	$41.9	$19.5	$16.4	54%	$28.3	$59.4	($4.3)
						2016-2022														
57	K19 Gas 750 MW	5	Base	High	-	4.40%	1.90%	64%	146%	$26.0	$20.6	$4.7	82%	$34.2	$16.4	$12.2	57%	$28.9	$62.4	-
58	K19 Gas 750 MW	5	DSM Level 1	High	-7%	4.77%	1.84%	63%	140%	$25.8	$20.4	$4.7	81%	$33.8	$16.2	$12.1	57%	$28.6	$59.7	($2.7)
59	K19 Gas 750 MW	5	DSM Level 2	High	-15%	4.86%	1.76%	57%	131%	$25.4	$20.1	$4.7	81%	$33.1	$15.6	$11.9	57%	$27.9	$57.2	($5.2)
60	K19 Gas 750 MW	5	DSM Level 3	High	-19%	5.33%	1.73%	59%	128%	$25.3	$20.0	$4.7	81%	$32.7	$15.2	$11.9	56%	$28.2	$56.8	($5.6)

* 2012 Constant dollar Consumers' Revenue discounted at 1.86% real discount rate

REFERENCE: Chapter 11: Financial Evaluation of Development Plans

QUESTION:

Please provide the full amortization schedule by year for amortizing each of the sunk costs for projects that do not (under various scenarios) proceed. Indicate which costs are being amortized and which type of costs (if any) are maintained as some form of deferred asset.

RESPONSE:

The following table provides a breakdown of the sunk costs by project and annual amortization expense associated with each project through to 2032/33 for the reference scenario. As indicated in MIPUG/MH I-003(a), total costs spent to June 2014 are assumed to be amortized over the 18-year period to 2032/33 for the purposes of the financial analysis. There are no costs assumed to be maintained in the form of deferred assets.

Conawapa Generating Station sunk cost amortization is applied in the All Gas (Plan 1), K22/Gas (Plan 2), K19/Gas/250 (Plan 4), and K19/Gas/750 (Plan 6) plans. Keeyask Generating Station and Transmission sunk cost amortization applies to the All Gas (Plan 1) and Gas/C26 (Plan 7) plans. The US Tie Line sunk cost amortization applies to the All Gas (Plan 1), K22/Gas (Plan 2) and Gas/C26 (Plan 7) plans. It should be noted that the sunk cost amortization under high capital cost/high economic indicator and low capital cost/low economic indicator scenarios do not change materially from the reference scenario.

Total Sunk Costs and Amortization Expense by Project:

(in $ millions)		Fiscal Year ------>																		
Project		**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Conawapa Generating Station	Total Sunk Cost	376.1																		
	Annual Amortization Expense	13.9	20.9	20.9	20.9	20.9	20.9	20.9	20.9	20.9	20.9	20.9	20.9	20.9	20.9	20.9	20.9	20.9	20.9	7.0
Keeyask Generating Station	Total Sunk Cost	1,186.7																		
	Annual Amortization Expense	51.8	65.9	65.9	65.9	65.9	65.9	65.9	65.9	65.9	65.9	65.9	65.9	65.9	65.9	65.9	65.9	65.9	65.9	14.2
Keeyask Transmission	Total Sunk Cost	13.4																		
	Annual Amortization Expense	0.4	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.3
US Tie Line	Total Sunk Cost	1.2																		
	Annual Amortization Expense	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0
	Total Sunk Cost	1,577.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total Annual Amortization Expense	66.17	87.64	87.64	87.64	87.64	87.64	87.64	87.64	87.64	87.64	87.64	87.64	87.64	87.64	87.64	87.64	87.64	87.64	21.46

TAB 2

Manitoba Hydro 2015/16 & 2016/17 General Rate Application
PUB/MIPUG-13

Chapter:	**P. Bowman Direct Testimony -Section 6.0 Figure 7**	**Page No.:**	**20**
Topic:	**Capital Expenditure**		
Subtopic:			
Issue:	**Forecast Capital Spending Changes**		

PREAMBLE TO IR:

QUESTION:

a) Please provide an analysis that identifies the main differences in CEF14 versus that presented in the NFAT.

RATIONALE FOR QUESTION:

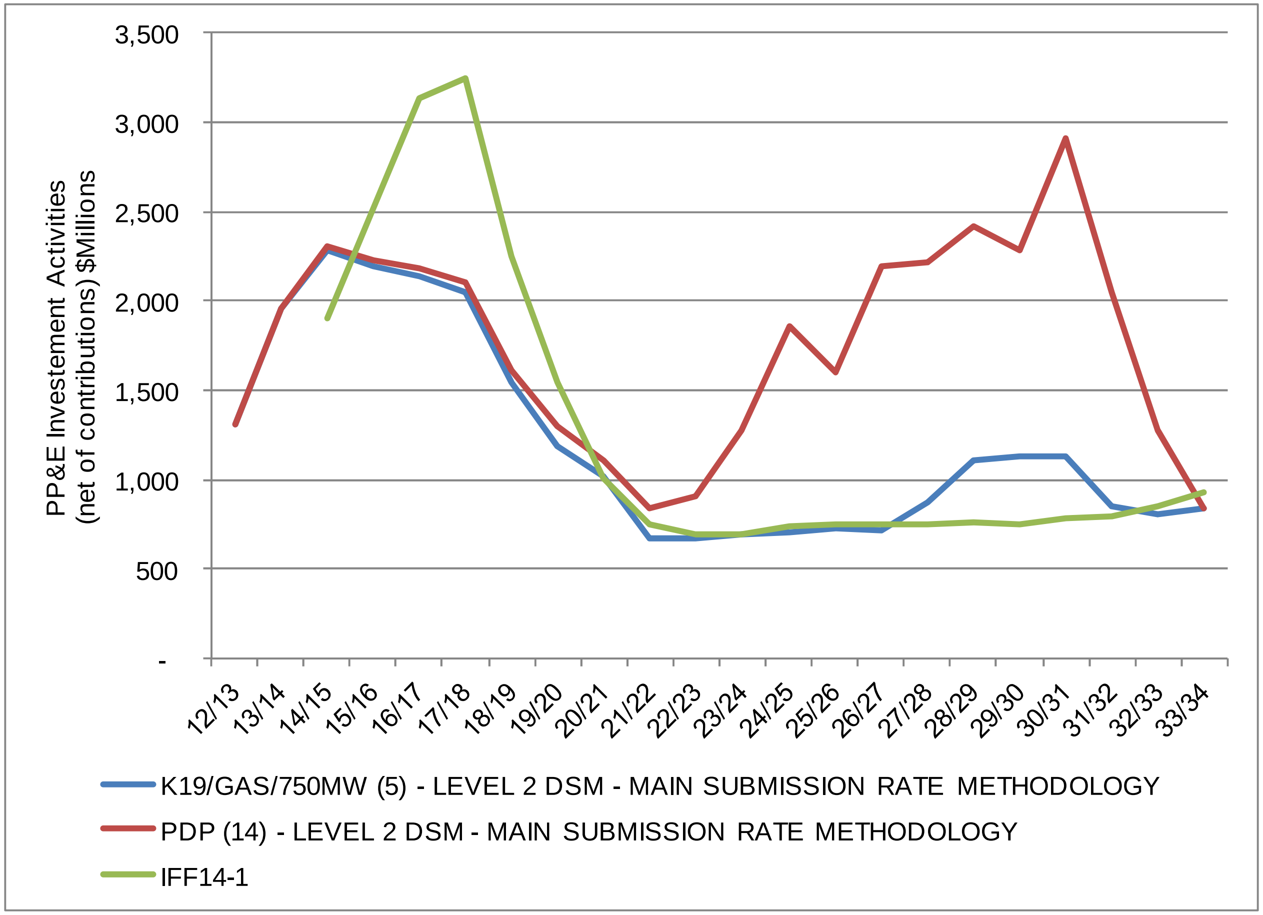
RESPONSE

(a)

Comparing the capital spending differences between CEF14 and NFAT plans is difficult because comparable capital plans were not provided for each NFAT plan.

Broadly, the total Property, Plant and Equipment contributions each year can be compared through the cash flow statements provided in Exhibit MH-104-12-1 in the NFAT review with the cash flow in IFF14 as is done in the graph (Figure 1) and Table 1 below. However, note that this includes major capital spending on Keeyask and Conawapa where relevant.

Figure 1: Comparison of PP&E Investment Activities from Cash Flow Statement ($ Millions)[1]



[1] Data from IFF14-1 Appendix 3.3: Electric Operations (MH14) Projected Cash Flow Statement page 40-41 and Exhibit MH-104-12-1 DSM Evaluation Pro Forma Financial Statements for Level 2 DSM with main submission rate methodology for Plan 5 (most comparable to Hydro's current plans) and Plan 114 (Hydro's Preferred Development Plan at the time which includes Conawapa).

Manitoba Hydro 2015/16 & 2016/17 General Rate Application
PUB/MIPUG-13

Table 1: Forecast PP&E Investment Activities from Cash Flow Statement ($ Millions)

($ Millions)	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23
K19/GAS/750MW (5) - LEVEL 2 DSM - MAIN SUBMISSION RATE METHODOLOGY	1,311	1,964	2,279	2,189	2,132	2,050	1,547	1,190	1,019	673	672
PDP (14) - LEVEL 2 DSM - MAIN SUBMISSION RATE METHODOLOGY	1,311	1,964	2,301	2,230	2,180	2,101	1,612	1,294	1,114	839	912
IFF14-1			1,900	2,518	3,134	3,244	2,253	1,550	1,010	756	698
	23/24	24/25	25/26	26/27	27/28	28/29	29/30	30/31	31/32	32/33	33/34
K19/GAS/750MW (5) - LEVEL 2 DSM - MAIN SUBMISSION RATE METHODOLOGY	692	702	732	719	872	1,104	1,128	1,129	853	805	837
PDP (14) - LEVEL 2 DSM - MAIN SUBMISSION RATE METHODOLOGY	1,277	1,859	1,599	2,196	2,211	2,423	2,283	2,913	2,045	1,277	842
IFF14-1	697	744	751	752	745	762	748	787	800	846	928

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From an overall spending analysis Hydro is now forecasting to spend over $3.2 billion more in the next 6 years (2014/15-2019/20) than forecasts from one year ago (K19/Gas). It should be noted that the above NFAT analysis includes the updated capital costs for Keeyask, Conawapa and BiPole-III that were reported in 2014.[2]

To review on a more detailed basis for major capital and administrative capital spending, CEF12[3] has been compared with CEF14[4] in Table 2.

The NFAT primarily used 2012 planning assumptions in the original preparation of the resource planning options (including the IFF12 and CEF12);[5] however changes were made during the review regarding Keeyask and BiPole total costs and level of DSM expenditures in the Major New Generation & Transmission spending that are not captured in CEF12. Table 2 assumes that the sustaining capital per NFAT should be basically consistent with CEF12 and therefore should be a reasonable representation of the common capital expenditures across all NFAT plans (in this case Plans 5 and 14). These values are used as a comparison to CEF14 to determine the main differences in expenditures other than Major New Generation & Transmission.

[2] From Exhibit MH-104-8 in the NFAT review, page 1.
[3] Filed in IFF12 as Appendix A in the NFAT review.
[4] Filed as Appendix 4.1 in the 2015/16 GRA, compares only electric expenditures.
[5] NFAT Business Case, August 2013, Chapter 1, Section 1.4.2.5 NFAT Submission Planning Assumptions, page 21.

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Table 2: Comparison of Major Capital and Base Capital (i.e. Sustaining Capital) from NFAT (CEF12) and CEF14 ($ Millions)

($ Millions)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Major & Base Capital - Generation/Power Supply										
CEF14	132.0	131.9	132.0	132.1	132.0	131.9	132.1	134.7	137.3	140.1
CEF12	178.5	180.7	166.1	142.9	191.2	126.9	181.4	161.1	192.5	185.7
Difference	**-46.5**	**-48.8**	**-34.1**	**-10.8**	**-59.2**	**5.0**	**-49.3**	**-26.4**	**-55.2**	**-45.6**
Major & Base Capital - Transmission										
CEF14	125.0	125.0	125.0	124.9	125.1	125.0	150.0	150.0	149.9	150.0
CEF12	148.9	124.0	67.5	39.2	42.4	45.3	49.3	72.5	93.0	106.4
Difference	**-23.9**	**1.0**	**57.5**	**85.7**	**82.7**	**79.7**	**100.7**	**77.5**	**56.9**	**43.6**
Major & Base Capital - Customer Service & Distribution										
CEF14	235.5	240.9	268.3	206.0	205.9	206.0	206.0	210.1	214.3	218.6
CEF12	185.8	175.1	142.8	144.7	147.5	150.5	153.5	187.1	207.6	221.7
Difference	**49.7**	**65.8**	**125.5**	**61.3**	**58.4**	**55.5**	**52.5**	**23.0**	**6.7**	**-3.1**
Customer Care & Marketing, Human Resources, Finance & Administration										
CEF14	78.4	79.2	59.3	59.3	59.4	59.5	59.6	59.9	61.1	62.3
CEF12	61.3	60.1	60.2	61.3	61.0	61.5	58.6	59.6	60.6	61.7
Difference	**17.1**	**19.1**	**-0.9**	**-2.0**	**-1.6**	**-2.0**	**1.0**	**0.3**	**0.5**	**0.6**
Total Major & Base Capital & Administrative										
CEF14	570.90	577.00	584.60	522.30	522.40	522.40	547.70	554.70	562.60	571.00
CEF12	574.50	539.90	436.60	388.10	442.10	384.20	442.80	480.30	553.70	575.50
Difference	**-3.60**	**37.10**	**148.00**	**134.20**	**80.30**	**138.20**	**104.90**	**74.40**	**8.90**	**-4.50**

In summary, Table 2 shows an increase for CEF14 compared with CEF12 (excluding Major New Generation and Transmission) of $534.2 million in the first six years (2015-2020), and of $717.9 million by 2023/24. The following analysis examines changes within each category in Table 2. However, within the first three of these categories, available data makes it difficult to compare all separate cost items between the two forecasts because CEF14 now lumps most costs in each category under a poorly enumerated "Base Capital" heading.

For **Major & Base Capital - Generation/Power Supply and Transmission**, these two categories must be assessed together as it is clear that HVDC work has changed classification between the two CEFs. The total impact is an increase in planned spending of nearly $200 million by 2024.

For **Major & Base Capital – Customer Service & Distribution** spending, the cumulative change for CEF14 compared with CEF12 is a capital cost increase of $416.2 million by 2020 and $495.3 million by 2024. However, given that the majority of spending is reported in “Base Capital” for CEF14 and in “Customer Service & Distribution Domestic” for CEF12, it’s not easy to analyze the cost differential based on Hydro’s filings to date or to understand a rationale for these increases since the NFAT, notwithstanding Hydro's list of construction works causing increases in the test years provided in PUB/MH I-18e.

For **Customer Care & Marketing, Human Resources, Finance & Administration**, the cumulative change for CEF14 compared with CEF12 is a capital cost increase of $29.7 million by 2020 and $32.1 million by 2024.

In general, the use in CEF14 of "Base Capital" as a summary grouping for all expenditures with a forecast of less than $50 million[6] adds a barrier to full review of the key changes since CEF12 (which reports all major capital individually).

Table 3 below attempts to compare Base Capital spending in CEF14 with CEF12 by summing all major capital projects under the $50 million total project spending threshold in CEF12 and the domestic expenditures for each of the first three major capital categories.

Table 3: Comparison of Capital Spending on Projects less than $50 Million or 'Base Capital' ($ Million)

($ Millions)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Generation/Power Supply Base Capital										
CEF14	98.9	101.6	71	55.7	77.2	72.7	118.1	97.8	110.7	98.7
CEF12	101.2	86.3	69.6	42.6	34.5	24.9	24.5	29.5	30.6	28.4
Difference	**-2.3**	**15.3**	**1.4**	**13.1**	**42.7**	**47.8**	**93.6**	**68.3**	**80.1**	**70.3**
Transmission Base Capital										
CEF14	73.2	57.3	68.3	94.8	84.8	76.1	66.5	64.7	63	128.2
CEF12	90.4	72.3	47.3	39.2	42.4	45.3	49.3	37.3	38	38.8
Difference	**-17.2**	**-15**	**21**	**55.6**	**42.4**	**30.8**	**17.2**	**27.4**	**25**	**89.4**
Customer Service & Distribution Base Capital										
CEF14	197	182.6	209.6	160.7	173	193.3	206	210.1	214.3	218.6
CEF12	165	152.8	142.4	144.7	147.5	150.5	153.5	156.6	159.7	162.9
Difference	**32**	**29.8**	**67.2**	**16**	**25.5**	**42.8**	**52.5**	**53.5**	**54.6**	**55.7**
Total Base Capital										
CEF14	369.1	341.5	348.9	311.2	335	342.1	390.6	372.6	388	445.5
CEF12	356.6	311.4	259.3	226.5	224.4	220.7	227.3	223.4	228.3	230.1
Difference	**12.5**	**30.1**	**89.6**	**84.7**	**110.6**	**121.4**	**163.3**	**149.2**	**159.7**	**215.4**

From the comparison of the above "Base Capital" forecasts it appears that Hydro has consistently increased expenditures or number of smaller projects with total budgets less than $50 million across all departments.

In summary, Table 3 shows an increase for CEF14 compared with CEF12 for the defined "Base Capital" (focused on items with costs under $50 million) of $448.9 million in the first six years

[6] As explained in PUB/MH I-18a.

(2015-2020), and of $1,136.5 million by 2023/24. Increases in this "Base Case" cost grouping as evaluated in Table 3 are spread over each major category:

- For **Base Capital - Generation/Power Supply**, the cumulative change for CEF14 compared with CEF12 is a capital cost increase of $118.0 million by 2020 and $430.3 million by 2024.

- For **Base Capital – Transmission**, the cumulative change for CEF14 compared with CEF12 is a capital cost increase of $117.6 million by 2020 and $276.6 million by 2024.

- For **Base Capital – Customer Service & Distribution** spending, the cumulative change for CEF14 compared with CEF12 is a capital cost increase of $213.3 million by 2020 and $429.6 million by 2024.

RATIONALE FOR REFUSAL TO FULLY ANSWER THE QUESTION:

TAB 3

MANITOBA PUBLIC UTILITIES BOARD

Re: MANITOBA HYDRO

GENERAL RATE APPLICATION

2012/13 AND 2013/14

Before Board Panel:

Regis Gosselin - Board Chairman

Raymond Lafond - Board Member

Larry Soldier - Board Member

HELD AT:

Public Utilities Board

400, 330 Portage Avenue

Winnipeg, Manitoba

December 10, 2012

Pages 1 to 419

-- we're forecasting and we've got -- I wouldn't want to see it -- it decline beyond where we're forecasting over the period, but I -- I -- I think we can manage that forward.

It is -- it is incumbent on us to -- to be in a position to generate those funds though, because unlike a -- an investor-owned utility, which can go to the market, it can -- it can get additional equity to inject in the business to -- to help manage its growth, we've followed a path at -- at Manitoba Hydro over the course of our history where -- where we do generate funds internally. The government doesn't tend to inject money into the business, nor does it take a dividend out, unlike many provincial Crown corporations across the country.

MR. BOB PETERS: In terms of building Conawapa, do you see the capital structure needed to support that project as being any different than the capital structure to support Keeyask?

MR. SCOTT THOMSON: Well, based on the projections and the outlook we've got, for a period of time the capital structure is going to be significantly high -- more highly leveraged. And we are projecting over -- over a twenty (20) year outlook that we'll -- we'll recover back to the -- the 75:25 capital structure that we've -- we've got today.

So, you know, in a perfect world, Mr. Peters, I think that I'd -- I'd be much more comfortable operating where we could maintain that throughout but -- but accepting that we -- we wouldn't be in a position to internally generate that -- that level of capitalization in a rapid period of time before we start generating revenues from the assets.

I mean, that's -- that's the other thing. In the -- in the lengthy pre-build time that we've got, we're not -- we're not generating any additional revenues off those assets. So over a -- a longer time frame we'll -- we'll see that coming back into balance and -- and again, beyond the sort of twenty (20) year outlook provided, we -- we can manage to operate for a decade or fifteen (15) years without significant new additions to capital because of the capacity that we're adding. I would see a much more modest outlook beyond that.

But we're going to increase out capital -- our net capital assets by about $15 billion over the next twelve (12) years or so. Assuming that we ultimately want to achieve 25 percent equity again, we need close to $4 billion of -- of equity additionally in the business over that time frame. And -- and absent the investment from an -- an outside party being the province, we've got to generate those funds over time.

So we are trying to strike a balance between, you know, the customer on the one hand and -- and the financial requirements of -- of the business over the long term. And ultimately our customers are -- are the owners, if you will, of the company as well. So they've got a vested interested in -- in the -- the financial well-being of the business. We're not -- we're not jacking up rates in order to enrich a shareholder here; the customers are the shareholder.

MR. BOB PETERS: Does the Province of Manitoba's guarantee of the repayment of Manitoba Hydro's debt obligations account then for about 30 percentage points on the capital structure? Let me -- you've got puzzled look and maybe I do to.

But you said you're familiar with the -- your 60:40 debt-equity in British Columbia, and your equity is going to fall to 10 percent in your revised forecast, correct?

MR. SCOTT THOMSON: M-hm. Yeah. That's -- that's right, I guess, at the trough.

MR. BOB PETERS: Yeah. And, therefore, does Manitoba Hydro see the provincial debt guarantee to repay any debt as being worth at least 30 percentage points on that capital structure?

MR. SCOTT THOMSON: Well, the -- it -- it has a -- it has an impact in that it -- it reduces our cost of borrowing generally. I mean, we -- we can operate with that kind of leverage and -- and not pay -- pay usurious bond rates. So whether -- whether -- I don't think I'd quite characterize it that it fills a 30 percent gap in equity. But -- but, over time, the -- the fact that we -- we can lean on the government, I think, allows us to operate with a -- with an -- an equity or a capital structure that's about 25 percent equity. And for -- for brief periods during heavy capital investment, we can -- we can push it beyond that.

Historically, we've been much more highly leveraged. But at the same time, we weren't -- you know, when we built Bipole 1, at least the federal government funded that initiative; we didn't have the financial capacity as an organization, as a corporation, to do it ourselves. We're -- we're in a much stronger position now because of -- because of the capital structure that we've built up over time.

MR. BOB PETERS: Did that answer include that, if maybe it wasn't worth 30 percentage points on the capital structure, maybe it was worth as much as fifteen (15), in terms of the difference between twen -- 40 percent and 25 percent?

(BRIEF PAUSE)

MR. SCOTT THOMSON: I see the chief benefit of the -- of the -- the debt guarantee as reducing the cost of borrowing over time, and -- and it does provide some comfort to rating agencies that -- that allow us to -- to operate with even higher leverage during a -- a period of build that -- that we're looking at.

I wouldn't be comfortable at all if -- if -- if we were to allow the -- the capital structure to decline at our highest point of leverage and then maintain it at that level over -- because I think we'd -- we'd be looking at downgrades, and I think that that could negatively impact the borrowing costs of the province as a whole.

MR. BOB PETERS: But Manitoba Hydro expects the generating stations will bring the capital structure back to a more favourable position from the revenues directly attributed to those generating stations.

Isn't that the plan?

MR. SCOTT THOMSON: Yeah, over the long term.

MR. BOB PETERS: And so in terms of quantifying it over the short term, you're not comfortable putting a number on it in terms of what -- what that provincial debt guarantee allows the Corporation to do that it would otherwise have to do with other equity infusions?

MR. SCOTT THOMSON: Well, I think that -- that, based on discussions that we -- we've had internally -- and we -- we do have discussions with -- with the rating agencies on a -- on an annual or more often basis -- that -- that they -- they've seen our outlooks and -- and provided -- and -- and given soft indications that, provided over time we move back towards our targeted capital structure, interest coverage and -- and that sort of thing, that -- that we can continue to operate and move forward with our plan.

MR. BOB PETERS: Is this Board to conclude, Mr. Thomson, that the Manitoba Hydro Electric board is comfortable, and if not comfortable, at least satisfied, that the capital structure that will deteriorate to 90 percent debt in the next ten (10) years is -- is satisfactory to them?

MR. SCOTT THOMSON: Yeah, we've -- we've spent a great deal of time talking with -- with the board about the outlook and -- and the implications on -- on rates. And -- and while again I think -- I think our -- all of our board members would be much more comfortable if -- if we -- if we were in a position where we could forecast lower -- lower rate increases over time, that would be positive and -- and would prefer to avoid leverage, the -- the degree of leverage that we've got and are -- are anticipating, but that they're -- they're prepared to move forward on the basis that -- that we've put in front of the Board.

MR. BOB PETERS: Can the Board take from your answer that -- well, I guess, as a matter of course, your board did approve the IFF12 back at their November meeting?

MR. SCOTT THOMSON: Yes, they did, subject to some adjustments, which have been made and have been filed. It wasn't -- there was -- there was a great deal of discussion at the board table.

MR. BOB PETERS: We -- Ms. Ramage doesn't generally let me get very far with those discussions of the witnesses. But the net result of -- from what I can tell, of IFF12 is expenses up on capital projects 4 billion, revenues from exports down

3 billion, so it's a $7 billion less favourable position than IFF11-2?

MR. SCOTT THOMSON: Yeah, I don't think you can compare the dollars to dollars in quite that way. But the -- but the revenue over the period is down -- down the -- the roughly, you know, based on the numbers that you provided and -- and the capital cost outlook. But those costs would be recovered over the life of the assets, you know, seventy (70) to a hundred years in -- in some cases.

MR. BOB PETERS: And as for consumer rate increases, rare is the time I get to correct my colleague, Mr. Williams, but instead of what the Board saw in -- in 11.2 as a rate increase of 3 1/3 percent for twelve (12) years, which I think was up from its previous projection in IFF-09, the new projection is approximately 4 percent for eighteen (18) years?

MR. SCOTT THOMSON: Yeah, we've -- the -- the levelized increase is just under 4 percent over that time frame.

(BRIEF PAUSE)

MR. BOB PETERS: You said in a previous answer, Mr. Thomson, that the Corporation has to try to find a balance as between its financial picture and the -- the interests of its domestic consumers. Did I adequately rephrase you?

MR. SCOTT THOMSON: I think that's fair.

MR. BOB PETERS: And in -- in terms of -- can you tell this Board how Manitoba Hydro determines where that balancing point is?

MR. SCOTT THOMSON: Well, we -- again, looking at over the -- the longer term -- in -- in the near term we're seeking to recover the -- the cost of service over the -- over the -- the two (2) year test period. And we've lost a significant revenue stream, and that's -- that's at the heart of what's driving our -- our two (2) year test period rate requests.

I don't think it's -- it's prudent for us to operate at a loss. And -- and the -- the rate increases that we've asked for over the -- the two (2) year test period keep us in the black, and modestly so if you look back over the -- the earnings history that we've -- we've had over the la -- since 2004, the last drought period.

You know, we're -- we're marginally favourable, marginally profitable over the two (2) year test period assuming that we get the rate increases.

And -- and absent those rate increases we're operating at a loss.

Longer-term, we've -- we've seen the deterioration in our -- in our financial results and -- and the outlook, the long-term outlook, as a consequence of the lost export revenue. And that -- that -- you know, three (3) or four (4) years ago our outlook was a lot stronger, and it -- it has a significant impact over the long term on us. And -- and that's what's really driving our longer-term outlook on -- on rates.

If that changes three (3), four (4), five (5) years out and -- and is substantially more favourable then we're anticipating, we'll be in a position to pull back. We're -- we're not seeking rate increases at this time beyond the two (2) year test period. And clearly we'd -- we'd revisit that every year as we move forward.

But what -- what I'd -- I am concerned about is artificially suppressing the -- the rate -- the rate increases now and then facing a situation where, you know, you might get a couple of periods of drought in the twenty (20) year -- in the twenty (20) year time frame. And by deferring things, pushing a problem out into the future isn't going to make the problem go away. It's going to exacerbate the problem.

So if -- if we can make the adjustments and -- and get the rate increase that we're seeking here, we can maintain profitability. We can continue to deliver service to our customers and reliability, and -- and address the -- the challenges that we've got in maintaining the existing assets that we have in the short term.

And -- and again, if -- if circumstances change in -- out into the future, we'd be in -- we may -- favourably, then we'd be in a position to temper future rate increases. But -- and -- and I know Ms. Ramage might kick me under the table, but -- but that was one of the -- you know, one of the lengthy discussions we had at the board table when -- when the IFF was approved, you know. There was -- there was concern expressed, you know, these are above the -- the general rate of inflation.

Well, we are investing in new assets for the future of -- of the business over the longer term and the -- the twenty (20) year time horizon. That's what we're -- we're anticipating is going to be required to -- to be able to do that. If -- if our future revenue stream reverts back to the way it looked three (3) or four (4) years ago, we won't require increases of -- of that order of magnitude.

But if long-term bond rates go up, you know, a couple of percentage points, there -- there are a number of factors that could come into play five (5) years down the road that could be negative. And if we -- if we don't -- if we don't act prudently now, those problems are -- are going to get even tougher to deal with as we -- as we move forward.

MR. BOB PETERS: So the balance that Manitoba Hydro has put to it is to put additional rate pressures on domestic customers at approximately two (2) times inflation to try to keep Manitoba Hydro's head above water, at least keep it in the black?

MR. SCOTT THOMSON: That's -- that's what we're facing right now, because as -- as I said, if you -- if you put it in a context of reduction in export revenues on the order of $150 million, which represents, you know, double dig -- double-digit change in terms of -- of the overall domestic revenue stream in percentage terms, we've got to make up that shortfall somehow.

We -- we've enjoyed the benefit of the subsidy for a long time. The subsidy has gone away. But -- but we can't turn the Corporation on a dime. We can't shed cost at the same rate that -- that that decline in revenues happened. We -- we just -- we -- we can't do it and -- and operate safely and -- and effectively. So -- but that's the reality that we're facing. So we need -- we need to make up for that shortfall.

MR. BOB PETERS: And did I hear from your second-last answer, Mr. Thomson, that if the future risks turn negative, such as an unfavourable drought or bond rates go up and cost more for financing purposes, then even the numbers that are in IFF12 would be downgraded?

MR. SCOTT THOMSON: Yeah, I want to be careful. The -- the -- we planned for -- we planned for drought in our long-term plans. So based on -- on water flows over a hundred years, we -- we incorporate the effects of drought in our -- in our long-term forecast.

But when that will occur, it -- we know that it will happen and we're -- and we anticipate it will happen approximately, you know, on average in the same proportion. But we could have two (2) short term bursts of drought in -- in ten (10) years.

If we had a -- if we had an extended drought that we do plan for and -- and the -- the negative financial impact of that on the order of -- of close to $2 billion, if that hit us, then 80 percent of our equity disappears. If we have another negative impacts on the operations of the company a few years later, that really puts a strain on the business, so -- and -- and increases the leverage dramatically.

But we may have -- we may have a period of -- of strong water flows. The caution that I'd have there is we also anticipate having periods of strong water flow, and that's built into our long-term outlook as well.

So if things are -- are real good for a couple of years, you still have to plan for the bad times as well. And that -- and that's what the long-term IFF is designed to do. It's -- it -- it looks at the -- in the very short run, builds in the existing reservoir levels and -- and, in -- in the current year ahead, forecasts much more directly what we anticipate.

But over the long term, it's -- it's average water flows. And -- and we build that into our revenue forecast in terms of the -- the energy that's going to be available. And then we look at -- at a -- a group, a blend of -- of external forecasts in terms of what the market will pay for -- for the electricity. And -- and that has come off in recent years.

MR. BOB PETERS: And, Mr. Thomson, what

if the export market price doesn't -- doesn't double in the next five (5) years or triple in the next ten (10) years, as perhaps included in the forecast? Does that also mean it's a negative -- there's a negative impact on IFF12?

MR. SCOTT THOMSON: If -- if the -- if the actuals -- if the actual revenue levels are lower, then, yeah, it's going to negatively impact on our -- on our forecast.

MR. BOB PETERS: I want to pick up on a comment, Mr. Thomson. You said that Manitoba Hydro -- at least my recollection and what my notes said was you can't shed costs as quickly as -- as revenue has left the Corporation from exports.

MR. SCOTT THOMSON: Yes, that's right. We're a price taker in the opportunity market.

MR. BOB PETERS: All right. I want to turn away from what Hydro is doing to get more revenues through domestic rate increases to get your perspective on what Hydro is doing to find bottom-line revenues through internal savings from its $800 million of OM&A expenses.

Would it be fair and correct to say that at Fortis, an investor-owned distribution utility, you had to create financial efficiencies to deliver value and money to your shareholders?

MR. SCOTT THOMSON: Yes, we did. We looked at -- at productivity.

MR. BOB PETERS: And what creative solutions did you, as the CFO, come up with that you can briefly tell us were successful?

MR. SCOTT THOMSON: We did a bunch of process redesign. We had grown through -- through acquisition. And we were in -- we had the ability -- through that process, there were redundancies that were created and opport -- opportunities to -- to streamline. We looked at discretionary expenditures and minimized those.

And -- and, generally speaking, what we -- what we typically did in a budgeting exercise year to year was -- was look at -- it was a -- kind of a modified zero-base budgeting approach. But we looked at -- at the objectives of the business units and what they -- what it was that they had to achieve from year to year and -- and whether there were opportunities, based on investments in capital that could grade -- create operating productivity. We -- we built those into -- into the forecast's outlook.

There were -- we had the opportunity, being an investor-owned company, to provide performance-based incentives. But for the most part, it -- it focussed around the -- the mission of -- of the organizational units and -- and what they required to do their -- their job.

So typically, again, we built in -- we -- we looked at labour cost escalation. We looked at the -- the costs that were -- were non-controlled. And we allowed for those, and we -- we challenged the -- the business units internally to look for productivity improvements.

There's -- but -- but you can't -- you can't cost-cut your way to prosperity. There's a limit to -- to what can be achieved there at the absolute extreme. You -- you can't cut below zero. And -- and we obviously can't operate a utility with the geographic scope of this one without people, and their labour is our -- is our largest cost in -- in our operating cost structure.

MR. BOB PETERS: Mr. Thomson, in your ten (10) months that you've been at the helm of Manitoba Hydro, have you determined whether any of those efficiency improvements that you just spoke about can be transferred to Manitoba Hydro with -- with positive gains?

MR. SCOTT THOMSON: Well, I guess I'd -

- I'd first like to say that the Company's had a running start at it. They -- they've been examining and looking, going back some years, at -- at how costs can be minimized. And there have been further additional actions taken in the time that I've been here.

But what -- what we've really cha -- the executives have challenged the organization to do is when -- we have a certain amount of turnover of employees each -- each year and -- and attrition through -- through retirements and those sorts of things, and a hiring freeze, if you will, was -- was put in place, and then -- then exceptions are -- are allowed. But basically challenging the -- the Company to look at whether or not we needed to replace every position that -- that -- when -- when people either retire or move on, whether they can -- whether the work could be accomplished differently and/or whether the work needs to continue to be done or could be done in -- in a somewhat different way.

And -- and for the most part, what -- what we've seen is that the -- the actions and activities that -- that we're undertaking were manned -- were manned appro -- were -- were staffed appropriately.

I think over the longer haul, to make material changes in -- in our -- our co -- our operating cost structure we'd have to -- to focus on whether there are things that our customers don't truly value that we do and look at -- at, you know, what business are you in, so to speak. And that's -- that's a longer-term exercise.

MR. BOB PETERS: Have you come up with any concrete plan, in terms of dollars and cents and timelines, that you'd like to target in terms of those efficiencies yet?

MR. SCOTT THOMSON: We're -- we're in the planning staging for those things now, again, looking at core business review and requirements. And -- and so, no, I don't have -- I don't have a timeline that I can share with you right now.

MR. BOB PETERS: Did you, at Fortis, or your colleagues there, Mr. Thomson, ever benchmark the Fortis/Terasen group of companies against peers?

MR. SCOTT THOMSON: Yes, we did, although it's -- it's always a challenge in -- in the utility industry across Canada. The -- the geography's covered. The -- the customer mix can have a pretty significant bearing on -- on how -- how you have to staff up and, as well, your -- your operating philosophy or strategy.

Some utilities -- and -- and we were Fortis -- the Fortis companies tended to operate this way, did -- did an awful lot of the construction work, had outsourced a lot of its -- its construction work. So we were -- we were more an operate and maintain organization as -- as opposed to the way that -- that Hydro is configured, where -- where a significant proportion of our -- our staff are devoted to capital activities.

And -- and we're an integrated utility. We generate. We transmit. We distribute. The Fortis focus had been predominantly on distribution, as opposed to -- we had some generation on the electricity side, some transmission some transmission assets on the gas side, but -- but no production, no exploration.

So while -- while in absolute numbers, you know, we had over a million customers between gas and electric and -- and substantially smaller employee footprint, we didn't operate in -- in big chunks of -- of that -- of the -- the supply chain that -- that Manitoba Hydro operates under.

MR. BOB PETERS: Did those benchmarking activities when you were in British Columbia yield the discovery of best practices in any area that you weren't currently or your company wasn't currently involved in?

MR. SCOTT THOMSON: Well, through the industry associations that -- that we belonged to and -- and which were the -- the two (2) larger ones in Canada being the Canadian Gas Association and Canadian Electricity Association, most of the -- the -- both of those associations have operating sub-groups within them, and there's an awful lot of information sharing through -- through that process.

But we -- actually, one of the areas that we -- we benefited most was internal benchmarking. Again, Fortis had operated over broad geography in BC similar to the way that -- that Manitoba Hydro does here. And so there was regional operations, and -- and looking at the differences, you know, across -- across our own organization was -- was often times helpful in -- identifying improvement opportunities that might exist. And we're doing that here.

MR. BOB PETERS: In the process of doing that here?

MR. SCOTT THOMSON: Yes.

MR. BOB PETERS: Thank you. And you mentioned in an answer to me that when you were with Fortis or Terasen, there was also performance-based incentive rates, is that -- some performance-based measures that were -- existed?

MR. SCOTT THOMSON: Yeah, we -- well we -- our -- our rate-making -- I think what you're -- what I was referring to is -- was there were performance based incentives for -- for staff.

MR. BOB PETERS: Oh.

MR. SCOTT THOMSON: Our remuneration structure was -- was much different.

MR. BOB PETERS: But you also had performance-based rates?

MR. SCOTT THOMSON: From time to time, we operated under -- under PBR regimes, yes.

MR. BOB PETERS: And in those regimes, rates would be set. And any efficiencies you found, you could keep the profit so to speak, at least for a period of time?

MR. SCOTT THOMSON: Well, they were shared wi -- back with customers and then ultimately rebased.

MR. BOB PETERS: When you were also with FortisBC, you had to deal with IFRS?

MR. SCOTT THOMSON: Yes, we did.

MR. BOB PETERS: And your decision, on behalf of your company at that time, was to move --

shall I say, away from IFRS and you went and supported US GAAP?

MR. SCOTT THOMSON: Yes, we worked -- we worked within the process and advocated strongly with -- with industry participants to -- to try and get the -- the implementation rules for IFRS changed to re -- to recognize rate regulated accounting in Canada. Ultimately that, when it appeared that the -- the international standard setters weren't going to go down that path we -- we were forced to examine alternatives and -- and changed courses and adopted US GAAP.

MR. BOB PETERS: I want to turn in the time I have remaining to talk about Manitoba Hydros role in developing the energy policies in the Province of Manitoba. And again, I'm sure if in your ten (10) months here, or you're comfortable answering these questions Mr. Thomson ,but please tell me.

Can you explain to this Board, what role, if any, Manitoba Hydro has in developing energy policies in the Province of Manitoba?

(BRIEF PAUSE)

MR. SCOTT THOMSON: Broadly, I guess we -- we have interactions on an ongoing basis with --

with various different government departments. And -- and of course the minister responsible for -- for Hydro has access to our -- our board -- our board meeting minutes and -- and materials, so we're invited to comment from time to time on -- on things that they're contemplating and -- and we do provide -- provide our input and our perspectives on -- on how we feel that that might impact on our operations. But ultimately the -- it's -- it's the province's prerogative to set energy policy.

MR. BOB PETERS: Okay, ag -- agreed. And -- but Manitoba Hydro would be expected to implement many of the province's energy policies.

Wouldn't that also follow?

MR. SCOTT THOMSON: Yes.

MR. BOB PETERS: And what happens -- what can you tell the board if there's a -- call it a disagreement, as between the province and Manitoba Hydro? Do they -- they have the trump card?

MR. SCOTT THOMSON: My colleague here said, "We lose." Well, ultimately, management and myself re -- report to the board. And -- and but -- but the -- the government ultimately has -- has the -- the ability to direct us to -- to do certain things.

MR. BOB PETERS: Yup.

MR. SCOTT THOMSON: Either through legislation . . .

MR. BOB PETERS: You know, for example, and -- and I'm -- I -- I don't know of any disagreements, first of all, that may exist or not, so, I'll -- I'm just going to pick a few things that I -- I've thought about and I'll use them and you would -- you can tell the Board if they apply or how -- how it would be determined and if the province has a certain desire, let's say, for wind generated electricity. And Manitoba Hydros desire doesn't line up with that.

Would Manitoba Hydro be given an opportunity to try to influence the province's decision, maybe not to be quite as aggressive?

MR. SCOTT THOMSON: Well, we -- we have dialogue around -- around those -- those types of things. The -- the most recent -- or recently where the -- the government came out with their clean energy strategy. And -- and it does speak -- speak to wind.

Ultimately, our -- our objective is to -- to meet the energy needs of the -- of the -- the people of the province and -- and to do that as cost effectively as we can. So we -- we examine our resource options that we have available to us and -- and we identify which are the -- the most cost effective ways to go.

And -- and we do have wind in our -- in our supply stack. And we -- we see value to having wind in our -- our supply stack. But -- but, currently, the cost of -- of generating that -- that product and -- and from time to time we have other parties that bid into, or -- or come to us with proposals to -- to sell wind to us, we have to look at what that value is to us on our system.

And -- and more recently it's been -- it hasn't been economically viable to -- to initiate new projects. We can't afford to pay what it would cost a Proponent to -- to build wind and what they're looking for in terms of long term supply contracts. So in order for us to -- to enter into those agreements, we feel it would be detrimental to -- to our customers presently. And over time that -- that may well change and -- and we'll continue to revisit it from time to time.

MR. BOB PETERS: I want to pick up on a comment you made about Manitoba Hydro's mandate being to provide energy to satisfy the needs of the province. And you look at your resource options from, I think your words were, a least cost options. Would that be right?

MR. SCOTT THOMSON: Yeah, the most -- most economic options for the Corporation.

MR. BOB PETERS: And what if, for example, there were options that maybe have larger benefits to the province than would be -- when weighed against the impacts to consumers of the Manitoba Hydro resource option preferred plan? How does -- how does the province and Manitoba Hydro deal with those types of issues?

MR. SCOTT THOMSON: Well, fortunately, based on -- on the most, you know, the most recent development plan outlook that we've got, the -- the -- there's -- there's congruence, I'd suppose you'd say. The -- the resource options that we'll be pursuing are the most economic for the Corporation and they have the -- the additional benefit of providing -- providing benefits to the province as a whole, and sort of outside the -- the fence of the -- the Corporation. So we haven't really run into that at this point.

MR. BOB PETERS: Well, my -- my point more finely, Mr. Thomson, is does Manitoba Hydro ever factor in the benefits to the province as a whole, over and above the utility when it looks at these -- these issues?

MR. SCOTT THOMSON: We -- we have

looked at that. And -- and we'll -- we'll deal with that, I believe, at some length in the NFAAT process on -- on the resource development plans.

MR. BOB PETERS: All right. Maybe the last area then, Mr. Thomson, is -- if you'll indulge me. When you were with Terasen Gas and Fortis, I understood from your previous answers that you were responsible for rate and other filings with the British Columbia Utilities Commission?

MR. SCOTT THOMSON: Yes.

MR. BOB PETERS: And -- and better alert Ms. Ramage to have her hand at the ready here, but did Fortis and Terasen file documents in confidence with the BCUC?

MR. SCOTT THOMSON: Yes, and/or documents were dealt with in-camera at -- from time to time.

MR. BOB PETERS: And those would be documents that you would consider to be key documents in decision-making processes?

MR. SCOTT THOMSON: Yes, and they were commercially sensitive.

MR. BOB PETERS: And when you said you dealt with them in-camera, did that mean the -- the Intervenors were excluded from the hearing room, or were they still left in the hearing room?

MR. SCOTT THOMSON: It depended on the nature. In some instances, the -- the panel received filings or -- or the commission received filings, certain -- certain gas supply contracts or storage arrangements. And they didn't have public input on them. They -- they dealt with them themselves.

MR. BOB PETERS: Well, for those contracts -- and you'd be talking largely natural gas, I suppose, commodity and transportation contracts?

MR. SCOTT THOMSON: In that case, yes.

MR. BOB PETERS: Was there a redacted version put on the public record?

MR. SCOTT THOMSON: Generally not.

MR. BOB PETERS: And in some circumstances, when the commercial sensitivity was seen as less, the Board went in-camera to deal with them?

MR. SCOTT THOMSON: Yes. Generally speaking, that was the case. Occasionally, cer -- certain -- at times, some items were dealt with through confidenti under -- confidentiality undertakings of -- of participants, as well.

MR. BOB PETERS: And that was the point I was going to come to, was that -- can you just explain to the Board how that worked? It would be

Intervenors, their lawyers, their representatives.

They would have to sign confidentiality undertakings not to disclose the information?

MR. SCOTT THOMSON: Yes. And it was the Board's discretion as to whether -- based on submissions of parties, whether -- whether that was reasonable in the circumstances or whether the Board would just -- just review it themselves.

MR. BOB PETERS: Mr. Chairman, I'd like to thank Mr. Thomson for fielding my questions and providing his answers. I've enjoyed the opportunity to ask them of him. It's a bit wide ranging. And I look forward that maybe our -- our paths will cross again, maybe on or off the microphone. But thank you, sir.

MR. SCOTT THOMSON: Thanks.

THE CHAIRPERSON: Thank you, Mr. Peters. Mr. Williams...?

CROSS-EXAMINATION BY MR. BYRON WILLIAMS:

MR. BYRON WILLIAMS: Yes, thank you, members of the Board. And, Mr. Thomson, you'll find, as you see more of these hearings, that while Mr. Peters's questions tend to go on forever, mine -- mine tend to be quite a bit shorter so.

MR. SCOTT THOMSON: I can't promise my

bottom line?

MR. SCOTT THOMSON: Again, I wasn't -- I wasn't aware that it was that significant, but I'll accept that.

MR. ANTOINE HACAULT: Are you familiar with a review of BC Hydro which was shown to have been completed in or about June of 2011, and also deals with its recommendations on cuts to staffing levels?

MR. SCOTT THOMSON: Yes, I'm familiar with that report.

MR. ANTOINE HACAULT: And do you recall at all the nature and extent of the cuts to the employee labour force that was recommended in that report?

MR. SCOTT THOMSON: My recollection, it was on the order of a thousand (1,000).

MR. ANTOINE HACAULT: That's pretty close to my calculation, too. The report indicates that the total equivalent staff numbers were five thousand eight hundred (5,800) and some in 2011, and the report was recommending that a reasonable staffing level would be in the order of forty-eight hundred (4,800) employees.

Does that sound right to you?

MR. SCOTT THOMSON: Yeah. I -- I seem

to recall that. What -- what -- again, what you need to be careful about when -- when you look at that, BC Hydro had outsourced significant components of its operations into separate subsidiaries that aren't encompassed by those numbers.

MR. ANTOINE HACAULT: But it is a real cut of about a thousand (1,000) employees that is being recommended, correct?

MR. SCOTT THOMSON: That's -- that's what the report suggested, yes.

(BRIEF PAUSE)

MR. ANTOINE HACAULT: Can you offer any insight on why those two (2) utilities would be able to make such huge cuts in their labour force and still continue to deliver their services?

MR. SCOTT THOMSON: I don't think that they'll be able to deliver their services in the same fashion that they had previously, which is what I was referring to.

I think that, you know, if you add back, for instance, on -- on BC Hydro's roughly twenty-five hundred (2,500) people that -- that work through Centra Business Services, which was their customer care and --

and certain other functions that they -- they had outsourced, that puts you on the order of about eight thousand (8,000) employees.

And where they -- where they are in terms of -- they've -- they've got a major generating project -- generation project that's -- that's underway now, the planning for the -- the Site C development, which is a 900-megawatt hydro project. And they do have refurbishment activities, but their -- their approach has been significantly to deal, as I understand it, with -- with outsourced activities.

So they haven't achieved the recommended changes yet, so I think that it may be premature to -- to attempt to answer why they can do it when they -- they haven't achieved the -- the overall savings, some of which they've done through attrition and -- and had been planned. And -- and again, a hiring freeze.

But the focus of their activities -- and I -- and -- and I'm much more familiar with -- with BC and -- and much less with -- with what they're planning in Quebec, but they -- I know that Que -- Hydro Quebec has a substantial workforce in terms of overall size.

MR. ANTOINE HACAULT: So, one of the differences might be that in Quebec they can order these cuts whereas the Public Utilities Board here has no such jurisdiction, they can only express concerns.

MR. SCOTT THOMSON: The -- the Regie in -- in Quebec, I don't think that they can order the staffing level cuts, they can set rates though, which provides a -- you know -- and in particular, more so, the investor-owned utilities, but your inability to achieve a return. And both Hydro Quebec and -- and BC Hydro set rates differently than -- than we do here. They -- it's -- it's a rate-based rate of return approach and they actually generate substantial revenues for the provincial treasury.

MR. ANTOINE HACAULT: I wasn't suggesting it was the Regie in Quebec that was ordering this. It was an announcement by the Minister of Finance that these cuts would in fact occur. I'd like you -- to take you to -- just general principles in rate setting as it relates to your vision for Manitoba Hydro.

So, if you had to describe to me -- and I'm asking you to please do so -- what's your vision as it relates to rate setting when it comes to Manitoba consumers?

MR. SCOTT THOMSON: Well, we'll continue to follow a -- a cost recovery approach while -- while planning for -- while planning for the future development of the province over time. We -- we do, as I had explained earlier, we do need to build up the -- the capital structure of the Company over time to -- to support -- to support our capital investment program for the benefit of our customers.

So our customers ultimately are going to pay for all of this and -- and we need to preserve the -- the capital structure of the Company. We've got to balance that off with the -- the rate pressures or -- sorry, yeah, the affordability question but both of those things need to be met. We -- as much as we'd like to, we can't -- we can't just maintain lates -- rates at a low level or -- or preserve rate increases at or below the rate of inflation at the expense of -- of the financial integrity of the Company, because that's not in our customers' interest long term either.

We -- we have the ability, and I think that from a -- from a policy or philosophical standpoint we have the ability that we don't have to match rates in lock step with -- with revenue requirements like -- and in a rate-based rate of return approach to rate setting would do, where you tend to have a lot more rate volatility. At least that's been my experience and that seems to be the -- the experience that -- that certainly BC Hydro has -- has seen over the last number of years.

We will endeavour to maintain the rate advantage vis a vis competing jurisdictions. It's -- it's important I think for -- for commercial and industrial customers who -- whose competition isn't in Manitoba that -- that relative to what's happening in -- in other jurisdictions their -- they can continue to see an advantage to -- to being here.

Our outlook suggests that that's -- that's doable, certainly in the -- in the short to medium term where -- where our rates are lower to start with. And while -- while they are projected to go up at greater than the rate of inflation, the competing hydro jurisdictions which tend to have the -- the lower rates have -- you know, BC's had high single digit increases the last couple of years, they've got literally billions of dollars of unrecognized costs that they're carrying on the balance sheet in deferral accounts that there's going to be a day of reckoning around.

So, I -- I think that even with the rate increases that we're anticipating, our customers will continue to enjoy an advantage over -- over the rest of Canada and -- and the US.

MR. ANTOINE HACAULT: Thank you. To

probe a little bit deeper into this -- and it was a -- a former chair of this Board who used to, I think, refer to the little old lady on Agnes Street, and whether it should be her or her grandchild that should be paying for Conawapa, take for example.

Do you have any visions, speaking corporately, that Manitoba Hydro has on whether that asset is used and useful for the little old grandma on Agnes Street or the grandchild?

MR. SCOTT THOMSON: Well, I think that -- that there -- there's sort of a spectrum of views in terms of dealing with the issue of inter-generational equity, which I think you're -- you're referring to. We've got a plan for -- for the long term, and ultimately maintain the -- so the -- maintain the financial integrity of the -- of the Corporation provides benefits to the -- to the little old lady.

It -- it also ensures that her -- her grandchildren will -- will have electricity down the road. Again, it's -- it's striking a balance. We're -- we're not recognizing the -- directly the -- the cost of service impacts of those projects until they -- they come into service other than, again, over time, we'll be looking to -- to beef up the -- the capital structure of the Company.

We're not -- we're not -- our -- what's before the Board right now in this two (2) year test period is not -- the rate increases aren't there to pay for future assets that are going to come into service in -- in 2025. They're -- they're to meet a shortfall in -- in revenues that are a consequence of the current market conditions largely.

MR. ANTOINE HACAULT: I'm not so sure I understand what the vision is from your perspective. You've explained you have to weigh things, but -- so is it the grandma who pays for the 25 percent equity, or should it be the grandchild?

MR. SCOTT THOMSON: I think the answer is both.

MR. ANTOINE HACAULT: Thank you. And who pays the greater part of it?

MR. SCOTT THOMSON: Well, the -- the cost of recovery of the assets will be over their -- their life and the -- the period of their use. So, generally speaking, it's the user that pays.

MR. ANTOINE HACAULT: In fact, for bigger projects, the capital, as you've indicated in your direct testimony, is expected to last eighty (80) to a hundred years except for the turbines in them. Is that correct?

MR. SCOTT THOMSON: Yeah, the civil works tend to have the -- the longer life -- lifetime.

MR. ANTOINE HACAULT: So even to that extent, if the grandchild is putting the 25 percent in, he's not likely to see all the benefits of his 25 percent contribution, correct?

MR. SCOTT THOMSON: Well, the -- the equity underpinning -- there's two (2) ways that we can -- we can get this. The government can inject it and -- and taxpayers, including the -- the grandchild and -- and the -- the old lady, are going to pay for it through taxes. And -- and the debt service cost currently or -- or over time, we're -- we're -- we will be amortizing the assets over their life and will recover those cost in rates.

And -- and the equity -- because we don't -- we don't generate revenue requirement around the equity; it offsets the -- the cost of the debt service. If we -- if we leverage it a hundred percent, you'd pay the -- the debt service costs on -- on the entire investment on a declining basis over its life.

So there is a benefit in rates to -- to capitalizing it because we don't earn an -- an 8 or 9 or 10 percent return on the equity. Our rate setting is not driven that way.

MR. ANTOINE HACAULT: Thank you. The next subject area which I'd like to touch on is IFR.

THE CHAIRPERSON: Excuse me, Mr. Hacault. Did you want to respond, Mr. Warden?

MR. VINCE WARDEN: Well, I -- I just wanted to clarify that although our application did include time-of-use rates for industrial customers, this Board has decided not to consider that in this proceeding. So the -- the -- or the -- any rate increase that we are granted for April the 1st, 2013, will be across the board.

CONTINUED BY MR. ANTOINE HACAULT:

MR. ANTOINE HACAULT: Thank you, and I didn't mean to cut you off. Sorry if you needed to respond. If -- if you do in the future, just let me know and -- okay.

When you testified in front of the Legislative Assembly on April 4 of 2012, you'd made some comments that you were involved in lobbying with respect to the International Accounting Standards Board, correct?

MR. SCOTT THOMSON: That's correct.

MR. ANTOINE HACAULT: And you made the statement in April to the effect that, frankly, the industry doesn't believe that IFRS -- that doesn't reg -- recognize regulatory accounting is appropriate.

On what basis is the industry against this principle that IFRS wants to implement?

MR. SCOTT THOMSON: When -- when the Europeans introduced IFRS broadly in the utility industry there and in Australia, they -- they de-recognized any -- any rate-regulated assets. And -- and there was also -- rate making -- again, there were some differences in -- as I understand it, in -- in European rate -- rate setting. Often it was targeted.

It wasn't the traditional cost -- cost-of-service-based approach that we -- we tend to use in Canada and the US. And so they didn't have the significant assets on their balance sheets that -- that many Canadian and US utilities have.

So -- like our demand-side management investments, which are expected to -- to yield benefits over an extended number of years. Under IFRS you've got to write them off as incurred. And -- and that's, in large measure, what -- what drives the change in our -- in our outlook where -- where you'll see going forward once we -- once we bring IFRS there's a decrease in our -- in our equity from year over year.

So the ability to recognize assets on

your balance sheet or -- or liabilities -- and, again, many companies have tracking accounts for commodity costs or power purchase costs where they -- the -- unlike us, where we just -- we accept that -- that the -- the costs are difference -- different than forecast for -- for electricity and it hits the bottom line.

Many utilities will -- will track that and -- and amortize it over a period -- short -- usually short term, but in -- in that case. But there are benefits to -- to having those accounts in place. And -- and they -- they tend to reflect the reality in those rate-making regimes where those costs are allowed to be recovered from customers.

And they match the -- they -- in our -- in my view and -- and generally, I think it's held in the industry that it better matches the revenues and expenses. It -- it reduces the amount of reported volatility in, and it also smooths -- tends to smooth -- have the potential to smooth rate making.

Now, regulators can -- can ignore the effects of those or -- or continue to have deferral accounts for -- for rate-making purposes. But again, then it starts to introduce a disconnect between your books of account for external reporting purposes and your books for -- for rate-making purposes. And -- and