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Ontario Energy Board

EB-2009-0084

Report of the Board

on the Cost of Capital for Ontario's Regulated Utilities

December 11, 2009

(2)

4 The Board's Approach

4.1 Summary of Key Principles

As discussed previously, the Board confirms the following key principles with respect to its cost of capital policy. The Board has analyzed submissions, discussions at the consultation and the final written comments of participants to the consultation with these general principles in mind.

1. **Fair Return Standard.** All three requirements – comparable investment, financial integrity and capital attraction – must be met and none ranks in priority to the others. It is not sufficient for a formulaic approach for determining ROE to produce a numerical result that satisfies the FRS on average, over time. The Board is of the view that each time a formulaic approach is used to calculate an allowed ROE; it must generate a number that meets the FRS, as determined by the Board using its experience and informed judgment.

2. **The overall ROE must be determined solely on the basis of a company's cost of equity capital**. It does not mean that in determining the cost of capital that investor and consumer interests are balanced. The opportunity cost of capital should be determined by the Board based on a systematic and empirical approach that applies to all rate-regulated utilities regardless of ownership. The Federal Court of Appeal was clear that the overall ROE must be determined solely on the basis of a company's cost of equity capital and that the impact of any resulting toll increase is an irrelevant consideration in that determination.

3. **Efficient amount of investment.** As it relates to a rate regulated entity's cost of capital, the role of the regulator is to determine, as accurately as possible, the opportunity cost of capital to ensure that an efficient amount of investment occurs in the public interest for the purpose of setting utility rates.

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4. **Predictability, transparency, and stability**. The approach adopted by the Board to determine the opportunity cost of capital should result in an environment where outcomes are predictable and consistent so that investors, utilities and consumers are better able to plan and make decisions.

5. **Systematic and empirically-based approach**. The methodology used by the Board to determine the cost of debt and equity capital should be a systematic approach that relies on economic theory and is empirically derived from objective, data-based analysis. For example, in establishing comparability, it is possible to build a low-risk sub-set from a higher risk universe using an empirically based approach.

6. **Minimize the time and cost of administering the framework.** Costs imposed on all participants, including the regulated entity and the regulator, should not exceed the benefits available. This objective could be met through a simple process that reflects the concerns of interested participants and reduces the formal process requirements.

4.2 Return on Equity

4.2.1 Need to Reset and Refine Existing ROE Formula

In order to ensure that on an ongoing basis changing economic and financial conditions are adequately and appropriately accommodated in the Board's formulaic approach for determining a utility's equity cost of capital**, the Board has determined that its current formula-based ROE approach needs to be reset and refined**. As previously indicated, **the Board will continue to use a formula-based ERP approach**. However, informed by the discussion at the consultation and the written comments of participants generated by the consultation, as well as its own analysis, the Board has concluded that the formula needs to be reset to address the difference between the allowed ROE arising from the application of the formula and the ROE for a low-risk proxy group that cannot be reconciled based on differences in risk alone. The formula also needs to be refined to reduce its

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Ontario

BY E-MAIL AND WEB POSTING

November 25, 2013

To: All Licensed Electricity Distributors and Transmitters
All Gas Distributors
Ontario Power Generation Inc.
All Registered Intervenors in 2014 Cost of Service Applications

Re: Cost of Capital Parameter Updates for 2014 Cost of Service Applications

The Ontario Energy Board (the "Board") has determined the values for the Return on Equity ("ROE") and the deemed Long-Term ("LT") and Short-Term ("ST") debt rates for use in the 2014 cost of service applications. The ROE and the LT and ST debt rates are collectively referred to as the Cost of Capital parameters. The updated Cost of Capital parameters are calculated based on the formulaic methodologies documented in the *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities* (the "Cost of Capital Report"), issued December 11, 2009.

Cost of Capital Parameters for 2014 Rates

For rates with effective dates in 2014, the Board has updated the Cost of Capital parameters based on: (i) the September 2013 survey from Canadian banks for the spread over the Bankers' Acceptance rate of 3-month short-term loans for R1-low or A:-(A-stable) commercial customers, for the Short-Term debt rate; and (ii) data three months prior to January 1, 2014 from the Bank of Canada, *Consensus Forecasts*, and Bloomberg LLP, for all Cost of Capital parameters.

The Board has determined that the updated Cost of Capital parameters for 2014 cost of service rate applications for rates with effective in 2014 are:

Cost of Capital Parameter	Value for 2014 Cost of Service Applications for rate changes in 2014
ROE	9.36%
Deemed LT Debt rate	4.88%
Deemed ST Debt rate	2.11%

Detailed calculations of the Cost of Capital parameters are attached.

The Board considers the Cost of Capital parameter values shown in the above table, and the relationships between them, to be reasonable and representative of market conditions at this time.

As documented in the *Report of the Board on Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors* (EB-2010-0379) issued November 21, 2013, the Board intends to update Cost of Capital parameters for setting rates in cost of service applications only once per year. For this reason, the Cost of Capital parameters above will be applicable for all cost of service applications with rates effective in the 2014 calendar year.

The Board monitors macroeconomic conditions and may issue updated parameters if economic conditions materially change. An applicant or intervenors can also file evidence in support of different Cost of Capital parameters due to the specific circumstances in individual rate hearings, but must provide strong rationale for deviating from the Board's policy.

All queries on the Cost of Capital parameters should be directed to the Board's Market Operations hotline, at 416 440-7604 or market.operations@ontarioenergyboard.ca.

Yours truly,

Original Signed By

Kirsten Walli
Board Secretary

Attachment

Ontario Energy Board
Commission de l'Énergie de l'Ontario

Attachment: Cost of Capital Parameter Calculations

(For Cost of Service rate changes effective in 2014)

Cost of Capital Parameter Calculations

Return on Equity and Deemed Long-term Debt Rate

Step 1: Analysis of Business Day Information in the Month

Month: September 2013

	Day	Bond Yields (%) Government of Canada 10-yr	Bond Yields (%) Government of Canada 30-yr	A-rated Utility 30-yr	Bond Yield Spreads (%) 30-yr Govt over 10-yr Govt	30-yr Util over 30-yr Govt
1	1-Sep-13					
2	2-Sep-13					
3	3-Sep-13	2.68	3.15	4.61	0.47	1.46
4	4-Sep-13	2.71	3.18	4.63	0.47	1.45
5	5-Sep-13	2.80	3.25	4.72	0.45	1.47
6	6-Sep-13	2.76	3.23	4.70	0.47	1.47
7	7-Sep-13					
8	8-Sep-13					
9	9-Sep-13	2.74	3.22	4.69	0.48	1.47
10	10-Sep-13	2.82	3.28	4.75	0.46	1.47
11	11-Sep-13	2.78	3.26	4.73	0.48	1.47
12	12-Sep-13	2.78	3.26	4.73	0.48	1.47
13	13-Sep-13	2.76	3.25	4.73	0.49	1.48
14	14-Sep-13					
15	15-Sep-13					
16	16-Sep-13	2.79	3.28	4.76	0.49	1.48
17	17-Sep-13	2.77	3.26	4.77	0.49	1.51
18	18-Sep-13	2.70	3.21	4.69	0.51	1.48
19	19-Sep-13	2.70	3.22	4.74	0.52	1.52
20	20-Sep-13	2.69	3.20	4.69	0.51	1.49
21	21-Sep-13					
22	22-Sep-13					
23	23-Sep-13	2.65	3.17	4.67	0.52	1.50
24	24-Sep-13	2.59	3.11	4.63	0.52	1.52
25	25-Sep-13	2.57	3.09	4.60	0.52	1.51
26	26-Sep-13	2.58	3.10	4.61	0.52	1.51
27	27-Sep-13	2.55	3.08	4.56	0.53	1.48
28	28-Sep-13					
29	29-Sep-13					
30	30-Sep-13	2.54	3.07	4.56	0.53	1.49
31						
		2.70	3.19	4.68	0.496	1.483
	Sources:	Bank of Canada		Bloomberg L.P.	❶	❷

Step 2: 10-Year Government of Canada Bond Yield Forecast

Source: *Consensus Forecasts*	Publication Date:	September 9, 2013	
	3-month	12-month	Average
September 2013	2.700	3.100	❸ 2.900 %

Step 3: Long Canada Bond Forecast

10 Year Government of Canada Concensus Forecast (from Step 2)	③	2.900 %
Actual Spread of 30-year over 10-year Government of Canada Bond Yield (from Step 1)	①	0.496 %
Long Canada Bond Forecast (LCBF)	❹	3.396 %

Step 4: Return on Equity (ROE) forecast

Initial ROE		9.75 %
Change in Long Canada Bond Yield Forecast from September 2009		
LCBF (September 2013) (from Step :	④ 3.396 %	
Base LCBF	4.250 %	
Difference	-0.855 %	
0.5 X Difference		-0.427 %
Change in A-rated Utility Bond Yield Spread from September 2009		
A-rated Utility Bond Yield Spread (September 2013) (from Step 1)	② 1.483 %	
Base A-rated Utility Bond Yield Spread	1.415 %	
Difference	0.068 %	
0.5 X Difference		0.034 %
Return on Equity based on September 2013 data		9.36 %

Step 5: Deemed Long-term Debt Rate Forecast

Long Canada Bond Forecast for September 2013 (from Step 3)	④	3.396 %
A-rated Utility Bond Yield Spread September 2013 (from Step 1)	②	1.483 %
Deemed Long-term Debt Rate based on September 2013 data		4.88 %

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Ontario Energy Board
Commission de l'Énergie de l'Ontario

Attachment: Cost of Capital Parameter Calculations
(For Cost of Service rate changes effective in 2014)

Cost of Capital Parameter Calculations
Deemed Short-term Debt Rate

Step 1: Average Annual Spread over Bankers Acceptance

Once a year, in January, Board staff contacts prime Canadian banks to get estimates for the spread of short-term (typically 90-day) debt issuances over Bankers' Acceptance rates. Up to six estimates are provided.

A.		Average Spread over 90-day Bankers Acceptance		Date of input
	Bank 1	100.0	bps	Sept., 2013
	Bank 2	100.0	bps	Sept., 2013
	Bank 3	82.5	bps	Sept., 2013
	Bank 4	80.0	bps	Sept., 2013
	Bank 5			
	Bank 6			

B.	Discard high and low estimates If less than 4 estimates, take average without discarding high and low.		
	Number of estimates	4	
	High estimate	100.0	bps
	Low estimate	80.0	bps

C.	Average annual Spread	91.250	bps	❶

Step 2: Average 3-month Bankers' Acceptance Rate

Calculation of Average 3-month Bankers' Acceptance Rate during month of September 2013

Month: September 2013

Day		Bankers' Acceptance Rate (%) 3-month	
1	1-Sep-13		
2	2-Sep-13	Bank holiday	%
3	3-Sep-13	1.20	%
4	4-Sep-13	1.20	%
5	5-Sep-13	1.20	%
6	6-Sep-13	1.20	%
7	7-Sep-13		
8	8-Sep-13		
9	9-Sep-13	1.20	%
10	10-Sep-13	1.20	%
11	11-Sep-13	1.20	%
12	12-Sep-13	1.20	%
13	13-Sep-13	1.20	%
14	14-Sep-13		
15	15-Sep-13		
16	16-Sep-13	1.20	%
17	17-Sep-13	1.20	%
18	18-Sep-13	1.20	%
19	19-Sep-13	1.20	%
20	20-Sep-13	1.20	%
21	21-Sep-13		
22	22-Sep-13		
23	23-Sep-13	1.20	%
24	24-Sep-13	1.20	%
25	25-Sep-13	1.20	%
26	26-Sep-13	1.20	%
27	27-Sep-13	1.20	%
28	28-Sep-13		
29	29-Sep-13		
30	30-Sep-13	1.20	%
31			
		1.200	% ❷

Source Bank of Canada / Statistics Canada
Series V39071

Step 3: Deemed Short-Term Debt Rate Calculation

Calculate Deemed Short-term debt rate as sum of average annual spread (Step 1) and average 3-month Bankers' Acceptance Rate (Step 2)

Average Annual Spread	0.913	%	①
Average Bankers' Acceptance Rate	1.200	%	②
Deemed Short Term Debt Rate	2.11	%	

Reference on Calculation Method:
- Appendix D of the *Report of the Board on Cost of Capital for Ontario's Regulated Utilities*, issued December 11, 2009.

IV. FAIR RETURN STANDARD

The fair return standard governs the assessment of the reasonableness of OPG's common equity ratio. The standards for a fair return arise from legal precedents which are echoed in numerous regulatory decisions across North America, including the OEB's *Cost of Capital Report.*[8] The *Cost of Capital Report*, citing the National Energy Board, states:

> A fair or reasonable return on capital should:
>
> - be comparable to the return available from the application of invested capital to other enterprises of like risk (the comparable investment standard);
> - enable the financial integrity of the regulated enterprise to be maintained (the financial integrity standard); and
> - permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (the capital attraction standard).[9]

As the OEB recognized in its *Cost of Capital Report*, the fair return reflects the aggregate return on capital, which incorporates the capital structure of the utility and cost rates for each element of the capital structure. With respect to equity, as the OEB stated in its most recent cost of capital determination for Enbridge Gas Distribution:

> The Cost of Capital Report indicates that the Board makes determinations on two elements in establishing the equity component of the cost of capital:
>
> 1) The deemed return on equity ("ROE"). This is a single rate of return set by the Board periodically for all utilities, considering overall market conditions; and
> 2) The deemed equity ratio, which is set by the Board for each utility individually, considering the circumstances of that particular utility.[10]

[8] The principal seminal court cases in Canada and the U.S. establishing the standards include *Northwestern Utilities Ltd.* v. *Edmonton (City)*, [1929] S.C.R. 186; *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia,(262 U.S. 679, 692 (1923))*; and, *Federal Power Commission v. Hope Natural Gas Company (320 U.S. 591 (1944))*. Each of these was cited in the *Cost of Capital Report.*

[9] National Energy Board, *Reasons for Decision, TransCanada PipeLines Limited, RH-2-2004 Phase 2, Cost of Capital*, April 2005.

[10] OEB, *In the Matter of an Application by Enbridge Gas Distribution Inc. for an Order or Orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas commencing January 1, 2013, Decision on Equity Ratio and Order, EB-2011-0354*, February 7, 2013, page 3 (hereafter referred to as "*EGD Decision on Equity Ratio*").

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Authorized Return on Equity for Canadian and U.S. Gas and Electric Utilities

Volume II, May 8, 2014

Concentric Energy Advisors, Inc. (Concentric) is pleased to publish the second edition of this newsletter. It summarizes authorized returns on common equity (ROEs) and common equity ratios for Canadian gas and electric distributors, Canadian electric transmission companies, U.S. gas and electric distributors, and select bond yields. Regulators, stakeholders, and analysts in Canada routinely consider allowed returns in other Canadian jurisdictions, and increasingly consider the comparability of Canadian and U.S. utilities when assessing the cost of capital. This newsletter seeks to assist with these inter-jurisdictional comparisons.

This newsletter and supporting database contain the authorized ROEs and common equity ratios for over 40 Canadian electric and gas utilities. For comparison purposes, the newsletter also presents the average and median authorized ROEs and common equity ratios for U.S. gas and electric distributors, as reported by SNL Financial's Regulatory Research Associates.

Concentric observes that the gap between authorized ROEs for Canadian and U.S. gas distributors continues to narrow, from 100 basis points in 2000 to 77 basis points in 2013 and to 35 basis points through the first three months of 2014. In 2013, the median authorized ROE for Canadian gas distributors was 8.93 percent, while the median for U.S. gas distributors was 9.70 percent. The difference also narrowed for electric distributors, but not to the same extent, where a larger gap between Canadian and U.S. distributors remains, 125 basis points in 2013 and 111 basis points in 2014. Concentric notes that gas ROEs are higher than their electric counterparts in Canada, while the opposite is true in the U.S.

Concentric attributes the closure of the gap between Canadian and U.S. authorized ROEs to the resetting and replacement of automatic formulas widely used in Canada to re-based ROE's and revised formulas or periodically litigated ROEs.

While authorized ROEs have converged in the two countries, the authorized common equity ratios have not. In 2013, the median common equity ratio for Canadian gas distributors was 40.5 percent while the same figure in the U.S. was 50.4 percent, comparable to the difference for electric distributors.

In this update, Concentric has added the allowed returns and equity ratios for Canadian electric transmission companies. Median ROEs are identical to those allowed for Canadian electric distributors, but 111–125 basis points below U.S. electric distributors over the 2013–2014 period. Allowed equity ratios for Canadian electric transmission companies are 3.0 percent lower than their electric distribution counterparts, and 13.0 percent below U.S. distributors.

Canadian utility regulators have issued several important ROE decisions since the first edition of this newsletter in October 2013. For example, in British Columbia, the BCUC set the allowed ROE and deemed equity ratio for the benchmark utility (FortisBC Energy Inc.) in May 2013 and for all other gas and electric utilities in the province in March 2014. The BCUC also decided to return to a formula (subject to government bond yields rising above a specified level). In Québec, the Régie revised the base allowed ROE for Hydro-Québec Distribution and Hydro-Québec TransÉnergie in March 2014 which had previously been set by a formula in place for more than a decade. The Régie further determined that an adjustment formula was not warranted at this time.

In Alberta, the AUC accepted evidence in a generic cost of capital proceeding in January 2014, with hearings scheduled for June and a decision is expected in the fourth quarter of 2014. The AUC will also rule on whether it is appropriate to return to an ROE formula, which was suspended in Alberta in 2009. In Ontario, the Ontario Energy Board's revised ROE formula established in December 1999 remains in effect, but will be subject to its first regular review in 2014. Union Gas recently settled its incentive rate plan, locking in the Board approved 2013 ROE of 8.93 percent for the five-year life of the plan.

Government and corporate bond yields are often considered when setting authorized ROEs for utilities. As shown in the chart on page 3, after declining for many years, the long-term government bond yields (considered the risk-free rate of return) in both Canada and the U.S. have been increasing since July 2012. While government bond yields play an important role in determining the authorized ROE for utilities, changes in government bond yields do not imply a one-for-one change in the cost of equity for utilities. The relationship between government bond yields and the equity risk premium (the spread between government bond yields and the cost of equity) has historically exhibited an inverse relationship.

Going forward, Concentric anticipates that improving economic conditions and the withdrawal of accommodative monetary policy in both Canada and the U.S. will continue to exert upward pressure on the cost of capital for utilities over the next several years.

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Authorized Return on Equity for Canadian and U.S. Gas and Electric Utilities [1]

	Return on Common Equity (%)			Common Equity Ratio (%)		
	2012	2013	2014	2012	2013	2014
Canadian Gas Distributors [2]						
AltaGas Utilities Inc. [3]	8.75	8.75	8.75	43.00	43.00	43.00
ATCO Gas [3]	8.75	8.75	8.75	39.00	39.00	39.00
Centra Gas Manitoba Inc.	N/A	N/A	N/A	30.00	30.00	30.00
Enbridge Gas Distribution Inc. [4]	8.39	8.93	9.36	36.00	36.00	36.00
Enbridge Gas New Brunswick	10.90	10.90	10.90	45.00	45.00	45.00
FortisBC Energy Inc.	9.50	8.75	8.75	40.00	38.50	38.50
FortisBC Energy (Vancouver Island) Inc.	10.00	9.25	9.25	40.00	41.50	41.50
FortisBC Energy (Whistler) Inc.	10.00	9.50	9.50	40.00	41.50	41.50
Gaz Métro Limited Partnership	8.90	8.90	8.90	38.50	38.50	38.50
Gazifère Inc.	8.29	7.82	9.10	40.00	40.00	40.00
Heritage Gas Limited	11.00	11.00	11.00	45.00	45.00	45.00
Pacific Northern Gas Ltd.	10.15	9.50	9.50	45.00	46.50	46.50
Pacific Northern Gas (N.E.) Ltd. (Fort St. John/Dawson Creek)	9.90	9.25	9.25	40.00	41.00	41.00
Pacific Northern Gas (N.E.) Ltd. (Tumbler Ridge)	10.15	9.50	9.50	40.00	46.50	46.50
SaskEnergy Inc.	8.75	8.75	8.75	37.00	37.00	37.00
Union Gas Limited	8.54	8.93	8.93	36.00	36.00	36.00
Average	9.46	9.23	9.37	39.66	40.31	40.31
Median	9.50	8.93	9.25	40.00	40.50	40.50

	Return on Common Equity (%)			Common Equity Ratio (%)		
	2012	2013	2014	2012	2013	2014
Canadian Electric Distributors [2]						
ATCO Electric Ltd. [3]	8.75	8.75	8.75	39.00	39.00	39.00
ENMAX Power Corporation [3]	8.75	8.75	8.75	41.00	41.00	41.00
EPCOR Distribution Inc. [3]	8.75	8.75	8.75	41.00	41.00	41.00
FortisAlberta Inc. [3]	8.75	8.75	8.75	41.00	41.00	41.00
FortisBC Inc.	9.90	9.15	9.15	40.00	40.00	40.00
Hydro-Québec Distribution	6.37	6.19	8.20	35.00	35.00	35.00
Manitoba Hydro	N/A	N/A	N/A	25.00	25.00	25.00
Maritime Electric Company Limited	9.75	9.75	9.75	41.70	43.50	43.10
Newfoundland and Labrador Hydro	4.47	4.47	Pending	20.00	20.00	Pending
Newfoundland Power Inc.	8.80	8.80	8.80	45.00	45.00	45.00
Nova Scotia Power Inc.	9.20	9.00	9.00	37.50	37.50	37.50
Ontario's Electric Distributors [4]	9.12	8.98	9.36	40.00	40.00	40.00
Saskatchewan Power Corporation	7.40	8.50	8.50	40.00	40.00	40.00
Average	8.33	8.32	8.89	37.40	37.54	38.97
Median	8.75	8.75	8.75	40.00	40.00	40.00

[1] Data for an expanded group of Canadian gas transmission companies is contained in the Concentric Energy Advisors Return on Equity Database.
[2] Allowed in rates for the corresponding year; where the year overlaps, the rate/ratio shown prevails for the majority of the year.
Sources: Regulatory decisions and documents; annual information forms; annual reports.
[3] The Alberta Utilities Commission opened a Generic Cost of Capital proceeding in 2013 to review the current allowed ROE for regulated gas and electric utilities in Alberta.
[4] Rates effective May 1 under the Board's formula. The ROE proposed for 2014 by Enbridge in its five-year incentive rate filing, July 3, 2013, EB-2012-0459, is 9.27 %. Union's 2014 ROE per settlement agreement in its five-year plan Beginning in 2014, the Ontario Energy Board intends to update cost of capital parameters for setting rates in cost of service applications only once per year.
* N/A indicates the data is not available.

CONCENTRIC ENERGY ADVISORS

	Return on Common Equity (%)			Common Equity Ratio (%)		
	2012	**2013**	**2014**	**2012**	**2013**	**2014**
Canadian Electric Transmission Companies [1]						
AltaLink Management Ltd.	8.75	8.75	8.75	37.00	37.00	37.00
ATCO Electric Ltd. [2]	8.75	8.75	8.75	37.00	37.00	37.00
ENMAX Power Corporation [2]	8.75	8.75	8.75	37.00	37.00	37.00
EPCOR Transmission Inc. [2]	8.75	8.75	8.75	37.00	37.00	37.00
Hydro One Networks Inc.	9.42	8.93	9.36	40.00	40.00	40.00
Hydro-Québec TransÉnergie	6.39	6.41	8.20	30.00	30.00	30.00
Average	8.47	8.39	8.76	36.33	36.33	36.33
Median	8.75	8.75	8.75	37.00	37.00	37.00

	Return on Common Equity (%)			Common Equity Ratio (%)		
	2012	**2013**	**2014**	**2012**	**2013**	**2014**
U.S. Gas Distributors [3]						
Average of all Rate Cases Decided in the Year	9.94	9.68	9.54	51.13	50.60	51.14
Median of all Rate Cases Decided in the Year	10.00	9.70	9.60	51.47	50.38	52.30
U.S. Electric Distributors [3]						
Average of all Rate Cases Decided in the Year	10.17	10.02	10.23	50.59	49.25	51.08
Median of all Rate Cases Decided in the Year	10.08	9.90	9.86	51.72	50.84	50.00

Economic Indicators (% Yields) [4]	**2012**	**2013**	**2014**
Government of Canada Benchmark Long-Term Bond Yield	2.45	2.82	3.02
U.S. Treasury 30-Year Bond Yield	2.92	3.45	3.68
Bloomberg Fair Value Canada A-rated Utility Bond Yield	3.91	4.24	4.36
Moody's A-rated Utility Bond Index (U.S.)	4.13	4.48	4.56

Presented by Concentric Energy Advisors, Inc. For more information regarding this data, please contact:

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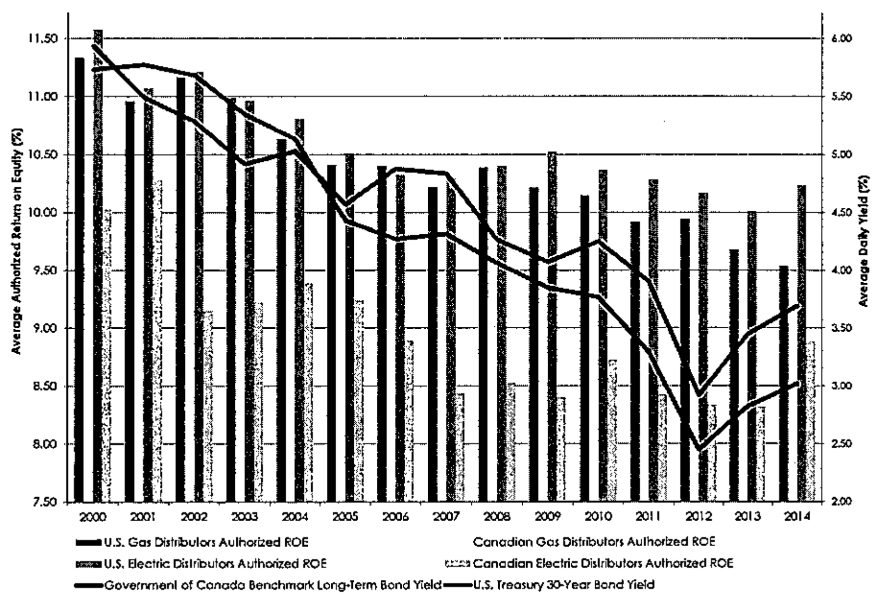

[1] Allowed in rates for the corresponding year; where the year overlaps, the rate/ratio shown prevails for the majority of the year.
Sources: Regulatory decisions and documents; annual information forms; annual reports.
[2] The Alberta Utilities Commission opened a Generic Cost of Capital proceeding in 2013 to review the current allowed ROE for regulated gas and electric utilities in Alberta.
[3] Source: SNL Financial LC's Regulatory Research Associates Division. Data for 2014 includes decisions through March 31, 2014.
[4] Average daily yield. Source: Bloomberg Finance L.P. Data for 2014 through March 31, 2014.

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BRITISH COLUMBIA UTILITIES COMMISSION

IN THE MATTER OF THE UTILITIES COMMISSION ACT
R.S.B.C. 1996, CHAPTER 473

And

Re: British Columbia Utilities Commission
Project No. 3698659/G-20-12

Generic Cost of Capital Proceeding

Vancouver, B.C.
December 13, 2012

PROCEEDINGS

BEFORE:

D. Cote,	Panel Chair / Commissioner
M. Harle,	Commissioner
L. O'Hara,	Commissioner
R. Giammarino	Commissioner

VOLUME 3

Allwest Reporting Ltd.
#1200 - 1125 Howe Street
Vancouver, B.C. V6Z 2K8

utility return out? Is that what you'd like me to do?
MR. WALLACE: Q: Okay, no, you are taking out comparable earnings already --
MS. McSHANE: A: Oh, I see, we are serially removing tests?
MR. WALLACE: Q: That is correct.
MS. McSHANE: A: Okay, well, if you take out the test with the next highest number, then the arithmetic says the number will be lower.
MR. WALLACE: Q: But when you take out the historic utility, would you then change your financing flexibility again or --
MS. McSHANE: A: No, that has nothing to do with it. It has to do with a type of test, not the value of the test.
MR. WALLACE: Q: I'd like to turn to business risk. You list six basic factors that you look at in your evidence at page 39 to 41, and then you look at them generically in terms of the type of operation on pages 45 to 48, and there you rank them from lowest to highest risk is electric transmission, electric distribution, gas distribution, and then integrated electric utility with alternative energy providers as the riskiest.

Has this risk ranking of yours been stable? I mean have you made significant changes in the

methodology over the last 10 years?
MS. McSHANE: A: In the methodology?
MR. WALLACE: Q: Well, in your risk ranking, the method -- or what you have shown here, is that what you have used over the last 10 years or have you changed it?
MS. McSHANE: A: Well, this isn't a method. This is -- if I could just back up and give you a little bit of context. The reason this is in here was because the commission asked in the minimum filing requirements for someone to do a relative risk ranking of these specific sectors. So, the job fell to me, to do this assessment. So what I tried to do was to set out for the Commission's benefit what I thought the specific factors were that would lead to the different rankings of these sectors.

Proceeding Time 11:39 a.m. T31

So I don't think that there's anything in the different sectors that's changed materially. Let's say in the last 10 years.
MR. WALLACE: Q: Okay, and --
MS. McSHANE: A: Can I just add one thing. The alternative energy service providers was -- was a sector that's very specific to B.C. and that was -- that's in here because the Commission asked to have that sector looked at as well.
MR. WALLACE: Q: Okay, can we put some company names to

situation.
MS. McSHANE: A: The fact that the utility, or the pipeline, can seek assistance from the regulator?
MR. WALLACE: Q: Yes.
MS. McSHANE: A: Oh, sure, yes.
MR. WALLACE: Q: Okay. Now, when we -- going back to your companies, then, in general, and I won't include all of them, but I take it that in terms of the companies you have listed, your risk ranking is generally AltaLink, then Newfoundland Power, then FEI and the other gas companies, then FortisBC and last would probably be NSPI?
MS. McSHANE: A: Okay. So we want to limit this to those specific companies, is that the idea?
MR. WALLACE: Q: That would be fine for the moment, yes.
MS. McSHANE: A: Okay. So let's start again?
MR. WALLACE: Q: Okay. We have AltaLink. Then Newfoundland Power. Then FEI -- with it, the other gas companies. Then FortisBC, and last would probably be NSPI.
MS. McSHANE: A: I think given the companies that you named, in terms of fundamental business risk, I would generally agree with you. I would like to just make sure that we are on the same page as far as the gas distribution utilities are concerned. I don't think I

would put them all in the same bucket, if you will, with FEI. I mean, there are some differences among them. I would consider ATCO Gas, for example, to be less risky than FEI. Enbridge Gas to be less risky than FEI.

MR. WALLACE: Q: Okay. I wasn't going to rank within the gas companies at this stage. I was simply going to take them in the --

MS. McSHANE: A: That's fine. I just didn't want to leave the impression that we were lumping them all together.

MR. WALLACE: Q: I'd like now then to turn to FEI business risk. You point out in your evidence that FEI derives 90 percent of its margin from residential and commercial customers. Do you agree with that?

And the reference is page 49, line 1252.

MS. McSHANE: A: Yes, that's correct.

MR. WALLACE: Q: And you go on to say that "of which over 80 percent is from space and water heating appliances."

MS. McSHANE: A: Correct.

MR. WALLACE: Q: And you indicate, of course, also, and we've been told, that FEI is capturing a smaller share of new construction and use is declining.

MS. McSHANE: A: Correct.

MR. WALLACE: Q: In terms of declining use, is this --

Requirement:

Plant in service continuity schedule (by function) including beginning balance, additions, asset retirements, ending balance, accumulated depreciation beginning balance, depreciation/accretion expense, retirements, accumulated depreciation ending balance, and net plant.

Submission:

Please refer to Partially Confidential Attachment 1.

Nova Scotia Power Inc.
Continuity Schedules for 2011A, 2012C, 2012F, 2013, 2014
(Numbers in thousands)

2011A

Function	Beginning Balance Gross Plant - 2011A	Additions - 2011A	Retirements - 2011A	Ending Balance Gross Plant - 2011A	Accumulated Depreciation Beginning Balance - 2011A	Depreciation/ Accretion Expense - 2011A	Retirements, Salvage and Cost of Removal - 2011A	ARO Adjustment 2011A	Accumulated Depreciation Ending Balance - 2011A	Net Plant - 2011A
Generation										
Steam	1,965,056	8,620	-23,952	1,949,724	827,517	52,634	-23,952	3,040	859,239	1,090,485
Gas Turbine	33,022	-186	0	32,836	24,836	957	0	-170	25,623	7,214
LM6000	83,503	-53	0	83,450	17,574	2,663	0	29	20,266	63,184
Wind Turbine	219,692	-9,114	0	210,578	2,468	10,199	0	-596	12,071	198,507
Hydro	424,451	30,897	-4,664	450,684	148,396	7,110	-4,664	-924	149,918	300,766
Transmission	650,286	68,330	-6,290	712,326	328,823	17,410	-8,170	-3,377	334,686	377,640
Distribution	1,198,117	62,176	-17,480	1,242,813	654,621	48,765	-21,161	-4,244	677,980	564,833
General Property	343,476	87,904	-3,562	427,818	179,902	28,073	-3,306	2,020	206,690	221,128
Totals	4,917,603	248,574	-55,948	5,110,229	2,184,136	167,810	-61,253	-4,221	2,286,473	2,823,757

2012C

Function	Beginning Balance Gross Plant - 2012C	Additions - 2012C	Retirements - 2012C	Ending Balance Gross Plant - 2012C	Accumulated Depreciation Beginning Balance - 2012C	Depreciation/ Accretion Expense - 2012C	Retirements, Salvage and Cost of Removal - 2012C	ARO Adjustment 2012C	Accumulated Depreciation Ending Balance - 2012C	Net Plant - 2012C
Generation										
Steam	2,051,120	104,021	-1,087	2,154,054	875,004	55,443	-1,087	-3,770	925,591	1,228,464
Gas Turbine	33,805	1,954	-326	35,433	25,534	1,092	-326	-168	26,133	9,300
LM6000	83,503	116	0	83,619	20,204	2,106	0	-105	22,205	61,414
Wind Turbine	218,981	-800	0	218,181	13,263	8,223	0	-1,273	20,213	197,968
Hydro	454,130	35,256	-350	489,035	151,898	9,538	-350	-1,442	159,645	329,391
Transmission	721,015	36,525	-593	756,948	344,293	16,398	-593	-358	359,740	397,208
Distribution	1,250,946	72,437	-1,372	1,322,011	708,541	49,950	-1,372	-2,527	754,591	567,420
General Property	437,220	15,406	-379	452,246	208,082	32,443	-379	0	240,145	212,101
Totals	5,250,720	264,914	-4,107	5,511,527	2,346,819	175,195	-4,107	-9,644	2,508,263	3,003,264

Forecasts are compiled for purposes of this rate application and are not intended to be relied upon for other purposes.

REDACTED

Row	2013									
57	Function	Beginning Balance Gross Plant - 2013	Additions - 2013	Retirements - 2013	Ending Balance Gross Plant - 2013	Accumulated Depreciation Beginning Balance - 2013	Depreciation/ Accretion Expense - 2013	Retirements, Salvage and Cost of Removal - 2013	ARO and Streetlight Adjustment 2013	Accumulated Depreciation Ending Balance - 2013	Net Plant - 2013
59	**Generation**										
60	Steam	2,088,641	245,533	-8,768	2,325,406	906,250	63,508	-8,768	-2,199	958,792	1,366,614
61	Gas Turbine	33,016	36	0	33,052	26,551	1,079	0	-164	27,466	5,586
62	LM6000	83,450	0	0	83,450	22,331	2,188	0	-37	24,483	58,968
63	Wind Turbine	210,952	0	0	210,952	15,976	8,186	0	-449	23,713	187,239
64	Hydro	474,466	31,829	-4,889	501,406	154,638	10,456	-4,889	-1,081	159,123	342,283
66	**Transmission**	764,948	74,469	-7,724	831,693	343,453	19,004	-11,400	0	351,057	480,635
68	**Distribution**	1,287,779	82,572	-20,417	1,349,933	696,423	50,720	-23,207	3,944	727,879	622,054
70	**General Property**	465,463	29,085	-4,014	490,533	234,709	37,585	-3,985	0	268,310	222,224
72	**Totals**	5,408,716	463,523	-45,812	5,826,426	2,400,332	192,726	-52,248	14	2,540,823	3,285,603

Row	2014									
76	Function	Beginning Balance Gross Plant - 2014	Additions - 2014	Retirements - 2014	Ending Balance Gross Plant - 2014	Accumulated Depreciation Beginning Balance - 2014	Depreciation/ Accretion Expense - 2014	Retirements, Salvage and Cost of Removal - 2014	ARO and Streetlight Adjustment 2014	Accumulated Depreciation Ending Balance - 2014	Net Plant - 2014
78	**Generation**										
79	Steam	2,325,406	42,454	-9,029	2,358,832	958,792	65,371	-9,029	-2,315	1,012,819	1,346,013
80	Gas Turbine	33,052	1,629	0	34,681	27,466	1,097	0	-173	28,390	6,291
81	LM6000	83,450	0	0	83,450	24,483	2,188	0	-39	26,632	56,819
82	Wind Turbine	210,952	0	0	210,952	23,713	8,186	0	-473	31,426	179,527
83	Hydro	501,406	32,506	-2,958	530,954	159,123	11,163	-2,958	-1,138	166,191	364,764
85	**Transmission**	831,693	52,270	-7,314	876,649	351,057	21,014	-9,048	0	363,023	513,626
87	**Distribution**	1,349,933	82,522	-17,978	1,414,478	727,879	53,240	-20,818	1,735	762,037	652,441
89	**General Property**	490,533	28,661	-3,605	515,589	268,310	39,917	-3,570	0	304,656	210,933
91	**Totals**	5,826,426	240,042	-40,883	6,025,586	2,540,823	202,176	-45,424	-2,403	2,695,172	3,330,413

Forecasts are compiled for purposes of this rate application and are not intended to be relied upon for other purposes.

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Board Staff Interrogatory #014

Ref: Exh C1-1-1 page 1

Issue Number: 3.1
Issue: What is the appropriate capital structure and rate of return on equity for the currently regulated facilities and newly regulated facilities?

Interrogatory

At the bottom of page 1, OPG states:

> OPG is not proposing any changes to its capital structure as there have been no significant changes in the risks faced by OPG's **regulated** asset portfolio that are not otherwise addressed by proposals to establish new variance and/or deferral accounts as described in Ex. H1-3-1. **[Emphasis added]**

Board staff notes that a key aspect of OPG's application is a significant change to OPG's "regulated asset portfolio" through the addition of "newly regulated hydroelectric" facilities, per O.Reg. 312/03,

Please confirm that OPG is of the view that the newly regulated hydroelectric facilities have similar business risks to the existing prescribed nuclear and hydroelectric generation assets. If yes, please provide OPG's reasons for this view.

Response

OPG believes that the business risks associated with the newly regulated hydroelectric assets are lower than the existing nuclear generation assets. This view is consistent with that of the OEB which found in OPG's previous application that "business risks associated with the nuclear business are higher than those of the regulated hydroelectric business[1]". In addition, OPG believes that the business risks associated with the newly regulated hydroelectric assets are higher than the previously regulated hydroelectric assets, as described below. In providing these views, OPG has assumed that its proposal to extend the existing deferral and variance accounts to the newly regulated hydroelectric assets is accepted.

The number of facilities and dams (48 and 175 for the newly regulated versus 6 and 27 for the previously regulated) compared to their production (2014 forecast of 12.4 TWh for the newly regulated versus 20.1 TWh for the previously regulated), their geographic distribution and remoteness of many of the facilities, along with the variability of production associated with inland rivers, combine to contribute to the operational risk of the newly regulated plants. Additionally, owing to the geographic location of the units, the newly regulated units have greater exposure to First Nations' risks than the previously regulated units.

[1] EB-2010-0008 Decision With Reasons, Page 116

Extending the application of the currently approved Hydroelectric Water Conditions Variance Account and the Surplus Baseload Generation ("SBG") Variance Account to include 21 of the 48 newly regulated hydroelectric units addresses some of the higher risk of the newly regulated hydroelectric assets.

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B. CONCLUSIONS

Based on the analysis conducted, OPG's deemed common equity should, at a minimum, remain at 47%, based on the following:

1. The business risks specific to OPG's regulated hydroelectric generation operations, including the newly regulated facilities, are somewhat higher than when the Board issued *Decision 2010-0008*, due largely to the higher operating risks of the newly regulated facilities.

2. The fundamental business risks of the nuclear generation operations have not changed materially. The operating leverage has continued to rise as anticipated, leading to higher potential volatility in earnings for the nuclear generation operations. All other things equal, a thicker equity component would be required to dampen the volatility.

3. The lower end of a reasonable range of equity ratios for the regulated hydroelectric generation operations, including the newly regulated generation, consistent with their relative business risks and the fair return standard is, conservatively, 45%. As such, a 47% common equity ratio for OPG's combined hydroelectric and nuclear operations, given the latter's higher operating risks and increased operating leverage, remains reasonable even with the higher proportion of regulated hydroelectric generation rate base during the test period.

4. The Darlington Refurbishment, due to its size, will reverse the relative proportions of the test period hydroelectric and nuclear generation rate base. Capital structure decisions reflect longer-term, not test period, business risks. As the Darlington Refurbishment investment is more than double the combined rate base additions from the NTP and newly regulated hydro facilities, maintaining the approved 47% common equity ratio is, a conservative approach that OPG should revisit once a decision on the Darlington refurbishment has been reached.

5. The passage of the Green Energy and Green Economy Act, which created a Feed-in Tariff program designed to attract investment in renewable energy projects, combined with lower market demand, had raised the potential that OPG would experience surplus baseload generation ("SBG"). In *Decision EB-2010-0008*, the Board directed OPG to create a variance account to capture the impacts of SBG (Hydroelectric Surplus Baseload Generation Variance Account, or SBG Variance Account), rather than forecast its occurrence.

The following changes since *Decision EB-2010-0008* impact OPG's business and financial risk:

1. The scope of Ontario Regulation 53/05 is expected to be expanded, so that all of OPG's hydroelectric generating plants that are not governed by contracts with the Ontario Power Authority will be regulated by the OEB. The 48 newly regulated hydroelectric plants, with an aggregate capacity of approximately 3100 MW, will add approximately $2.5 billion to OPG's regulated rate base.

2. The Niagara Tunnel Project has been placed into service. OPG's current application is requesting an addition to the 2014 rate base of $1.4 billion related to the NTP. The NTP increases the diversion capacity of the existing Sir Adam Beck (SAB) diversion facilities by approximately 500 m^3 per second, increasing the average annual energy production at the SAB generating complex by 1.5 TWh.

3. The definition phase of the Darlington Refurbishment Project has continued. OPG received a decision in early 2013 from the Canadian Nuclear Safety Commission which agreed that the project will not result in any significant adverse environmental effects. In October 2013, the Minister of Energy of Ontario announced that the province would go ahead with the refurbishment of the Darlington nuclear station as part of its revised long-term energy plan, expected to be released before the end of 2013. The Darlington Refurbishment

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VII. TRENDS IN BUSINESS RISK OF OPG'S REGULATED OPERATIONS

A. CHANGED CIRCUMSTANCES SINCE *DECISION EB-2010-0008*

At the time of *Decision EB-2010-0008*, in which the Board had found that there had been no material change in business risks since EB-2007-0905 and confirmed the previously approved 47% common equity ratio:

1. The approved test period (2012) rate base was comprised of approximately 50% hydroelectric assets and 50% nuclear assets. Because the rate base financed by the OEB approved capital structure removes the Asset Retirement Costs (ARC), the rate base financed by the hypothetical capital structure containing 47% common equity was allocated 61.5% to the regulated hydroelectric rate base and 38.5% to the nuclear rate base (*EB-2010-0008 Payment Amounts Order*, Appendix A, Table 1A).

2. The Niagara Tunnel Project, on which construction began in 2006, was expected to be placed in service in 2013.

3. OPG had announced its intention to proceed with the refurbishment of the Darlington nuclear generation station, expecting to commence construction by 2016, at an estimated cost of \$6 to \$10 billion (2009\$). The Board noted in *Decision EB-2010-0008* that the project was larger than the 2012 nuclear generation rate base of approximately \$4 billion, which was comprised of \$2.4 billion financed by the capital structure and \$1.5 billion of ARC (*EB-2010-0008 Payment Amounts Order*, Appendix A, Table 1A).

4. The Board had declined to allow the inclusion of Construction Work in Progress related to the Darlington Refurbishment in rate base.

Numbers may not add due to rounding.

Table 4
Capitalization and Cost of Capital
Summary of Capitalization and Actual Cost of Capital
Calendar Year Ending December 31, 2012

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Actual Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Achieved Capitalization and Return on Capital:					
1	**Short-term Debt**	1	7.2	0.1%	1.79%	3.4
2	**Existing Long-Term Debt**	2	2,287.6	38.0%	5.13%	117.3
3	**Other Long-Term Debt Provision**	3	898.9	14.9%	5.13%	46.1
4	**Total Debt**	4	3,193.7	53.0%	5.23%	166.9
5	**Common Equity**	4	2,832.2	47.0%	4.73%	133.9
6	**Rate Base Financed by Capital Structure**	5	6,025.9	76.5%	4.99%	300.8
7	**Adjustment for Lesser of UNL or ARC**	5, 6	1,851.1	23.5%	5.43%	100.5
8	**Rate Base**	7	7,876.9	100%	5.09%	401.3

Notes:

1 Ex. C1-1-3 Table 2: Principal (line 13), Cost Rate (line 8), Cost of Capital (line 14).

2 Ex. C1-1-2 Table 4, line 39.

3 Debt required to balance capital structure with proposed rate base. See Ex. C1-1-2, Section 5.0. Cost rate is the same cost rate used for Existing/Planned Long-Term Debt (line 2) per EB-2010-0008 Decision with Reasons.

4 Capital Structure approved by the OEB in EB-2010-0008 as discussed in Ex. C1-1-1. Return on Equity from Ex. F4-2-1 Table 4, line 1 less line 29, less $19.6M of income tax variances recorded in variance and deferral accounts (from Ex. C1-1-1 Chart 1).

5 The portion of rate base to be financed by the capital structure approved by the Board excludes the lesser of the forecast of the average unfunded liabilities (UNL) related to Pickering and Darlington, and the average unamortized asset retirement costs (ARC) included in fixed asset balances for Pickering and Darlington.

6 Principal from C2-1-1 Table 2, line 32. Weighted Average Accretion Rate from EB-2012-0002, Ex. L1-7 SEC-11, Chart 2.

7 Ex. B1-1-1 Table 1 (Prev. Reg. Hydro) and Ex. B1-1-1 Table 2 (Nuclear). Newly regulated hydroelectric assets are not included in the Board Approved capitalization and Cost of Capital.

Table 2
Capitalization and Cost of Capital
Summary of Capitalization and Cost of Capital
Calendar Year Ending December 31, 2014

Line No.	Capitalization	Note	Principal ($M)	Component (%)	Cost Rate (%)	Cost of Capital ($M)
			(a)	(b)	(c)	(d)
	Capitalization and Return on Capital:					
1	**Short-term Debt**	1	192.2	1.9%	1.87%	7.0
2	**Existing/Planned Long-Term Debt**	2	3,372.7	33.9%	4.85%	163.6
3	**Other Long-Term Debt Provision**	3	1,712.1	17.2%	4.85%	83.0
4	**Total Debt**	4	5,277.0	53.0%	4.81%	253.6
5	**Common Equity**	4	4,679.6	47.0%	8.98%	420.2
6	**Rate Base Financed by Capital Structure**	5	9,956.7	87.8%	6.77%	673.9
7	**Adjustment for Lesser of UNL or ARC**	5, 6	1,389.5	12.2%	5.37%	74.6
8	**Rate Base**	7	11,346.1	100%	6.60%	748.5

Notes:

1 Ex. C1-1-3 Table 2: Principal (line 13), Cost Rate (line 8), Cost of Capital (line 14).
2 Ex. C1-1-2 Table 6, line 45.
3 Debt required to balance capital structure with proposed rate base. See Ex. C1-1-2, Section 5.0. Cost rate is the same cost rate used for Existing/Planned Long-Term Debt (line 2) per EB-2010-0008 Decision with Reasons.
4 Capital Structure approved by the OEB in EB-2010-0008 as discussed in Ex. C1-1-1.
Return on Equity reflects the last Cost of Capital Parameter Update reported by the OEB (Feb. 14, 2013).
5 The portion of rate base to be financed by the capital structure approved by the Board excludes the lesser of the forecast of the average unfunded liabilities (UNL) related to Pickering and Darlington, and the average unamortized asset retirement costs (ARC) included in fixed asset balances for Pickering and Darlington.
6 Principal from C2-1-1 Table 2, line 32. Weighted average accretion rate from Ex. C2-1-1, section 3.0.
7 Ex. B1-1-1 Table 1 (Prev. Reg. Hydro and Newly Reg. Hydro) and Ex. B1-1-1 Table 2 (Nuclear).

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Ontario Energy
Board

Commission de l'énergie
de l'Ontario

Ontario

EB-2011-0354

IN THE MATTER OF the *Ontario Energy Board Act 1998*, S.O.1998, c.15, (Schedule B);

AND IN THE MATTER OF an Application by Enbridge Gas Distribution Inc. for an Order or Orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas commencing January 1, 2013.

BEFORE: Cynthia Chaplin
Presiding Member and Vice Chair

Paula Conboy
Member

Ellen Fry
Member

DECISION ON EQUITY RATIO AND ORDER

February 7, 2013

Background

Enbridge Gas Distribution Inc. ("Enbridge") filed an application on January 31, 2012 with the Ontario Energy Board (the "Board") under section 36 of the *Ontario Energy Board Act, 1998*, S.O. c.15, Schedule B (the "Act") for an Order or Orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas commencing January 1, 2013.

The Board issued a Notice of Application dated March 2, 2012. Details on the various procedural steps which followed are available on the Board's website.

that the Board should reconsider the basis for its decision in EB-2006-0034. Enbridge had the right to seek a review of that decision, but did not do so. Parties and ratepayers are entitled to rely on the results of Board proceedings, subject to the established legal review mechanisms.

In EB-2006-0034, the Board performed an assessment of the change in Enbridge's risk and determined the appropriate equity ratio for Enbridge at that time. In this proceeding, the Board's task in assessing the change in risk is to examine how risk has changed from the time the issue was previously decided in EB-2006-0034. To extend the analysis to a date before the Board's last consideration of the issue would inappropriately revisit the basis for the Board's risk assessment in EB-2006-0034, which was embodied in the approved equity ratio at that time. If there is now information available which was not known when the equity ratio was previously set, this will inform the analysis of change in risk only to the extent it is relevant to the change in risk since the equity ratio was last set.

Accordingly, the Board will determine whether there has been a significant change in Enbridge's risk since the Board rendered its decision in EB-2006-0034 in 2007.

Regarding the risk of future events, the Board agrees with CCC that the relevant future risks are those that are likely to affect Enbridge in the near term. Any risks that may materialize over the longer term can be taken into account in subsequent proceedings. In considering the risk of future events, the Board will take into account the fact that, generally, the more distant the potential event, the more speculative is any conclusion on the likelihood that the risk will materialize.

Assessment of Change in Risk

Although Enbridge has presented evidence and argument concerning changes in its risk since 1993, its position is also that it has experienced a significant increase in its business and financial risk since 2007. Intervenors take the position that this is not the case. Although the intervenors' expert witness, Dr. Booth, expressed the view that risk has decreased since 2007, the intervenors do not focus on arguing this position. No party argued that the risk had declined sufficiently to warrant a decrease in the common equity ratio. The Board has therefore focused only on the question of whether the risk has increased significantly.

Enbridge provided listings of the bonds it has issued since 2007 and its estimated bond pricing for a hypothetical 10-year Enbridge bond issued in 2013. The estimated spread for the hypothetical 2013 10-year bond is 110 basis points. This the same as the spread for the 10-year Enbridge bond issued in 2007. This comparison does not indicate an increase in financial risk since 2007.

Enbridge also provided a listing of the spreads for bonds issued by several potentially comparable utilities. However, none of these utilities issued bonds with terms and timeframes comparable to Enbridge's 10-year bonds.[14]

Financial Results

The Board also examined Enbridge's financial performance since 2007. From 2007 to 2011, Enbridge exceeded its Board allowed return on equity. The financial information provided by Enbridge shows a net revenue sufficiency in the range of $21 to $40 million each year in relation to total revenue of approximately $1 billion. Enbridge's forecast for 2012 shows that it does not expect to reach its Board allowed return; however the amount of the forecasted shortfall is only $4 million in relation to forecast total revenue of approximately $1 billion.[15] Therefore Enbridge has not experienced a significant deterioration in financial results since 2007.

Accordingly, as discussed above, the Board concludes that Enbridge's market circumstances have not deteriorated significantly since 2007 in terms of access to capital, interest coverage ratio, credit ratings, debt terms or financial results, and that consequently Enbridge has not experienced a significant increase in financial risk since 2007.

Decision of the Board on Equity Ratio

The Board concludes that there has been no significant increase in Enbridge's business and/or financial risk since 2007. Accordingly, the Board finds that Enbridge's equity ratio shall remain at 36% and that a full FRS analysis is not required.

Settlement on Cost of Debt

Issue E1 in this proceeding is as follows:

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[14] Accordingly it was not necessary for the Board to consider the extent to which these utilities are comparable to Enbridge.
[15] Figures in this paragraph have been rounded.

Ontario Energy Board | Commission de l'Énergie de l'Ontario

Ontario

EB-2011-0210

IN THE MATTER OF the *Ontario Energy Board Act 1998*, S.O.1998, c.15, (Schedule B);

AND IN THE MATTER OF an Application by Union Gas Limited for an Order or Orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas commencing January 1, 2013.

BEFORE: Marika Hare
Presiding Member

Karen Taylor
Board Member

DECISION AND ORDER

Union Gas Limited ("Union") filed an application on November 10, 2011 with the Ontario Energy Board (the "Board") under section 36 of the *Ontario Energy Board Act, 1998* for an order of the Board approving or fixing rates for the distribution, transmission and storage of natural gas, effective January 1, 2013 (the "Application"). The Board assigned file number EB-2011-0210 to the Application and issued a Notice of Application on December 1, 2011. This is the first cost-of-service application for setting rates since 2007. From 2008 to 2012 rates were set under an Incentive Regulation Mechanism ("IRM") which adjusted rates through a mechanistic formula.

The Board issued its Procedural Order No. 1 on January 11, 2012, which established the approved list of intervenors for this proceeding. The list included:

unfunded short-term debt was approximately $130 million in 2004 which is higher than the current unfunded short-term debt component of $115 million. Union submitted that the Board should reach a similar conclusion in this proceeding and not make any adjustments to the short-term or long-term debt component.

Board Findings

Deemed Common Equity Thickness

The Board finds that a deemed common equity ratio of 36% is appropriate for the 2013 test year, consistent with the deemed common equity ratio that was in place over the 2007 to 2012 period, inclusively.

The 2009 Cost of Capital Policy of the Board at page 43 sets out that for natural gas distributors such as Union, deemed capital structure is determined on a case-by-case basis and that reassessment of a gas utility's capital structure will only be undertaken in the event of significant changes in the company's business and/or financial risks.

Union filed no evidence in this proceeding that demonstrates its business and/or financial risks have changed over the period that the IRM Settlement Agreement was in place. In fact, Union stated many times during the proceeding that its business and financial risks have not changed and that it accepts that its overall risk profile has not materially changed since 2006.

Union put forth two arguments to support its application for a 40% deemed common equity ratio. The first is that the current deemed common equity ratio of 36% is too low and has never appropriately reflected its business and financial risk. Second, that the deemed common equity ratio should be increased solely on the basis of comparability; i.e., because other Canadian utilities now have higher deemed common equity ratios, the Board should also approve a higher deemed common equity ratio for Union.

The Board will address each of these two arguments in turn.

The Board does not accept the proposition that the deemed common equity thickness of 35% as determined by the Board in 2004 and subsequently increased to 36% as a result of a Settlement Agreement was incorrect and that it did not adequately reflect Union's financial and business risk profile. Union has filed no evidence to support this position that the deemed equity ratio was not correct and the Board therefore gives this argument little or no weight.

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The Fair Return Standard ("FRS") requires that a fair or reasonable return on capital should:

- Be comparable to the return available from the application of invested capital to other enterprises of like risk (the comparable investment standard);
- Enable the financial integrity of the regulated enterprise to be maintained (the financial integrity standard); and
- Permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (the capital attraction standard).

Union's second argument focuses on the first part of the comparable investment standard – that the return on invested capital must be comparable. However, Union's argument fails to address the second part of the comparable investment standard, that being the issue of "enterprises of like risk". Union would have the Board increase (and potentially reduce) its deemed common equity ratio in lock-step with the decisions of other regulators, without an analysis of whether the utilities to which it is compared are enterprises of like risk.

The Board acknowledges that there was a general consensus on the Canadian utilities that intervenors and Union asserted were comparable. The Board notes, however, that neither Union nor the intervenors filed analytical evidence that demonstrated that these utilities are of like risk to Union. Rather, what evidence was presented was anecdotal, ad hoc, and incomplete.

The Board is aware that since the 2008 financial crisis, the deemed common equity ratios of certain Canadian rate regulated entities have been increased. However, no evidence was filed in this proceeding that set out the risks that resulted in findings supporting higher deemed common equity for these utilities and no evidence was filed that demonstrates Union faces similar risks.

Union reiterated throughout the proceeding that its business and/or financial risks have not changed since 2006.

Accordingly, there is no reasonable basis for the Board to increase Union's deemed common equity ratio above the 36% level presently reflected in rates.

The Board does not agree with the submission of SEC that a higher deemed equity ratio must be supported by benefits to ratepayers. The Board's obligation to determine the

STANDARD &POOR'S

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Business Risk: Excellent

We believe CU Inc.'s business risk will continue to be excellent based on its low-risk, regulated monopoly businesses that are expected to continue to generate stable and predictable cash flow, supporting credit quality. Cost-of-service rate of return regulation that applies to both ATCO Electric Transmission and ATCO Pipelines provides very stable ongoing cash flow. We expect that PRB that will apply to ATCO Electric Distribution and ATCO Gas beginning in 2013 will heighten regulatory risk during its roll-out and the initial five-year period, but remain consistent with an excellent business risk. Virtually all of the company's businesses are in Alberta and are Alberta Utilities Commission-regulated. We believe demand in the province is particularly strong due to above-average population growth and economic activity that is driving rate-base investment. We expect the regulator to continue to be reasonably transparent and predictable in its decisions. While historically there has been some regulatory lag on rate case approvals, we do not believe there have been any cost disallowances that have affected credit quality. Allowed rates of return and deemed equity layers are somewhat low compared with those of U.S.-based peers, but similar to those of other Canadian utilities. We believe there is limited market risk owing in part to provincial GDP per capita that is the highest in the country.

Financial Risk: Significant

We expect funds from operations (FFO)-to-debt coverage to remain relatively stable, with some temporary downward pressure as a result of the large capital program. CU Inc.'s policy is to maintain total debt-to-total capital in line with regulator-set deemed capitalization which is similar to other regulated utilities in Canada. We believe that in the next several years, as the company undertakes significant investment, the regulated rate base and total debt could double in size. During this period, we expect CU Inc. will generate negative free cash flow, which somewhat constrains its financial risk profile. Still, we believe cash flows are highly predictable and are largely insensitive to macroeconomic risk. We expect rate-base growth to continue driving cash-flow growth.

We expect continuation of a 2011 precedent establishing decision that enabled ATCO Electric transmission to include CWIP, for projects directly assigned from the Alberta Electric System Operator, in the rate base, leading to increased cash flow. However, while CWIP in the rate base provides significant cash-flow support, the company will only begin to collect depreciation in rates once projects are completed, leading to downward pressure on credit metrics in the interim. The same regulatory decision also provided the utility with favorable tax decisions. The 2011 decision was clear, indicating that this was not a generic decision but based on circumstances. Given that the C$1.6 billion Eastern Alberta Transmission line received approval in November 2012 we have assumed that regulatory support will continue for 2013 and 2014. This reinforces our assessment of supportive cost-of-service and rate-of-return regulation in Alberta.

Liquidity: Adequate

Our short-term and commercial paper ratings on CU Inc. are 'A-1'. We believe the company has adequate consolidated

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THE IMPACT OF PRICE REGULATION ON THE COST OF CAPITAL

by

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Brazilian Development Bank

and

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ABSTRACT: *This paper investigates how price regulation under moral hazard can affect a regulated firm's cost of capital. We consider stylized versions of the two most typical regulatory frameworks that have been applied in the most recent decades by regulators: Price Cap and Cost of Service. We show that there is a trade-off between lower operational costs and a higher cost of capital under Price Cap regulation and higher operational costs and a lower cost of capital under Cost of Service regulation. As a result, when the extent of moral hazard is not significant, Price Cap regulation generates lower welfare than does Cost of Service regulation.*

Keywords: regulation and investment, cost of capital, price cap regulation.

JEL Classification: L51

Die Auswirkung von Preisregulierung auf die Kapitalkosten

In diesem Beitrag wird untersucht, wie Preisregulierung bei Vorliegen von Moral Hazard die Kapitalkosten eines regulierten Unternehmens beeinflussen kann. Betrachtet werden stilisierte Versionen der beiden typischsten Regulierungsrahmen, die in den letzten Jahrzehnten von Regulatoren praktiziert worden sind: Price Cap und Cost of Service. Es wird gezeigt, dass es bei der Price Cap-Regulierung einen Trade-off zwischen niedrigeren Betriebskosten und höheren Kapitalkosten gibt und zwischen höheren Betriebskosten und niedrigeren Kapitalkosten bei der Cost of Service-Regulierung. Im Ergebnis generiert die Price Cap-Regulierung, wenn das Ausmaß an

* Camacho acknowledges the financial assistance of the University of Queensland and the Brazilian Development Bank, and Menezes acknowledges support from the Australian Research Council (ARC Grants DP 0557885 and 0663768). We are thankful to John Panzar, two anonymous referees and seminar participants at the ANU, the University of Melbourne, Universidad de Chile, PUC-Chile, Auckland University, Hong Kong University, the CAMA/Brookings Conference on the Economics of Infrastructure, the 2010 SAET Meeting (NUS), IMPA, FUCAPE and the National University of Singapore for useful comments. The usual disclaimer applies. E-mails: camacho@bndes.gov.br; f.menezes@uq.edu.au.

economic rent left for the entrepreneur under COS regulation. Whether the regulator will be able to set a lower price under PC than the expected price under COS will depend on the parameter values.

If $p(E) \geq \lambda$, then the rate by which the cost of debt increases under PC is sufficiently low and it is welfare enhancing to reduce prices because the positive impact on consumer surplus outweighs the negative impact on the firm's cost of capital (and the entrepreneur's profit). The regulator then sets the lowest price possible to extract all rent, such that the entrepreneur's participation constraint is binding. In this case, under both types of regulatory regime, the entrepreneur's expected profit is equal to zero. However, the firm's cost of capital is higher than k under PC regulation and equal to k under COS regulation. Thus, we have the following rule: if the entrepreneur undertakes $E = 0$ under PC regulation, then COS regulation is welfare superior. The reason is the same as in the previous case; that is, as the firm's cost of capital is higher under PC than under COS (instead of a higher rent under PC than under COS, as in the previous case), the regulator extracts less rent under PC than under COS. This rent differential allows the regulator to set a lower expected price under COS than the price under PC regulation. However, if the entrepreneur undertakes $E = \varepsilon$ under PC regulation, then there is a trade-off between a higher level of effort under PC regulation and a lower cost of capital under COS regulation. Whether the regulator will be able to set a lower price under PC than the expected price under COS will again depend on the parameter values.[12]

5 Conclusion

We have investigated the relationship between price regulation and the cost of capital in a two-period model in which the regulator faces moral hazard and an entrepreneur is capital constrained. In our model, the cost of debt is greater than or equal to the cost of equity. Thus, the entrepreneur chooses the minimum level of debt possible.

In contrast to previous papers, our model fully explores the implications of the timing associated with the price-setting process. Thus, we assume that, under COS regulation, price is set *ex post* to firm's investment and financing decisions and uncertainty resolution, so that the regulated revenue exactly covers the firm's operational and capital costs. Under PC regulation, we assume that the regulator sets an *ex ante* price cap before the firm's investment and financing decisions and before the resolution of uncertainty. This modelling choice allows us to fully explore the contrast between the cost-plus and fixed price nature of regulatory contracts.

We have established that, when the cost of capital under PC is equal to the risk-free rate, PC regulation generates at least the same level of welfare as does COS regulation. In particular, if the extent of moral hazard is significant, then PC regulation is welfare superior. However, when the cost of capital under PC regulation is higher than the risk-free rate (or when the entrepreneur's profit is positive because the rate by which

12 The optimal choice of effort under PC regulation when the cost of debt is higher than the risk-free return (or when the entrepreneur's profit is positive) will depend on the parameter values as described in cells three ($E = \varepsilon$), four ($E = 0$) and five ($E = \varepsilon$ and $E = 0$) of the second column of Table 3 in the appendix.

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BRITISH COLUMBIA UTILITIES COMMISSION

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VIA EMAIL

May 10, 2013

To: All Registered Parties

Re: British Columbia Utilities Commission
Project No. 3698660/Commission Order G-20-12
Generic Cost of Capital Proceeding

Enclosed please find the Commission's Decision on the Stage 1 of the Generic Cost of Capital proceeding.

Yours truly,

Erica Hamilton

EC/dg
Enclosure

PF/BCUC_GCOC/GC/BCUC-GCOC-Stage 1-Decision Release

Mr. Engen submits that the 10 year bond yield spread for BBB/A rated utilities has been volatile and as of July 6, 2012, is at 38 basis points (bps). This is less than the 100 bps common during the 2008 financial crisis. According to Ms. McShane, over the past 15 years, the average spread between typical A and BBB rated utilities has been 75 bps. (Exhibit B1-9-6, Engen Evidence, Appendix E, p. 34; Exhibit B1-9-6, Appendix F, Ms. McShane Evidence, p. 36)

Commission Determination

The Commission Panel accepts that continued access to debt capital at an attractive price is an important element which benefits the shareholder and may benefit the customer. Based on the evidence of Ms. McShane and Mr. Engen, a drop to the equivalent of a BBB rating by both rating agencies would result in a borrowing rate difference which would be significant. That being said, the Panel is mindful that credit agencies like Moody's rely upon the embedded cost of debt rather than the marginal cost of debt when calculating a utility's credit metrics as argued by AMPC/CEC. (FBCU Reply, p. 22) Based on the testimony of Ms. McShane the approved cost of debt for 2013 (at 40 percent equity) is 6.8 percent. The Panel notes that current marginal rates are substantially below this level. Therefore, we conclude that the embedded cost of debt is likely to be reduced over time, even in the event of a credit downgrade.

The Commission Panel will continue to be guided by the Fair Return Standard with its three tests of financial integrity, capital attraction and comparable return in determining an appropriate capital structure and ROE. The Panel supports the maintenance of an "A" category credit rating but only to the extent that it can be maintained without going beyond what is required by the Fair Return Standard.

The Commission Panel finds that there is sufficient evidence to conclude that the maintenance of an "A" category credit rating is desirable, but not at all costs.

2013 Generic Cost of Capital Proceeding
Application No. 1608918
Proceeding ID 2191

Alberta Utilities
Information Response No.1 to:
Canadian Association of Petroleum Producers
Ms. Kathleen C. McShane
Submitted: April 7, 2014

CAPP-Utilities McShane 08

Reference: Testimony pages 52-65, Capital Structures

Preamble: Ms. McShane discusses capital structure.

Request:

(a) Please confirm that Ms. McShane's conclusion of no change in the 2% across the board common equity ratio increase (page 54) is based entirely on credit spreads. If not please identify the passages in the testimony that address other factors supporting this recommendation.

(b) Please provide the longest maturity bonds issued by CU Inc., on behalf of the ATCO utilities for each year since 1990 with the associated yield at issue and equivalent long Canada bond yield.

(c) In terms of the credit metric analysis please confirm that, if long term recovery of capital risk increases, one tool regulators have at their disposal is to increase the depreciation rate so that the rate base can be recovered over the useful life of the asset. Please confirm that this is what the National Energy Board did for the TransCanada Mainline in 2003 when the economic useful life was reduced to 25 years (RH-1-2002).

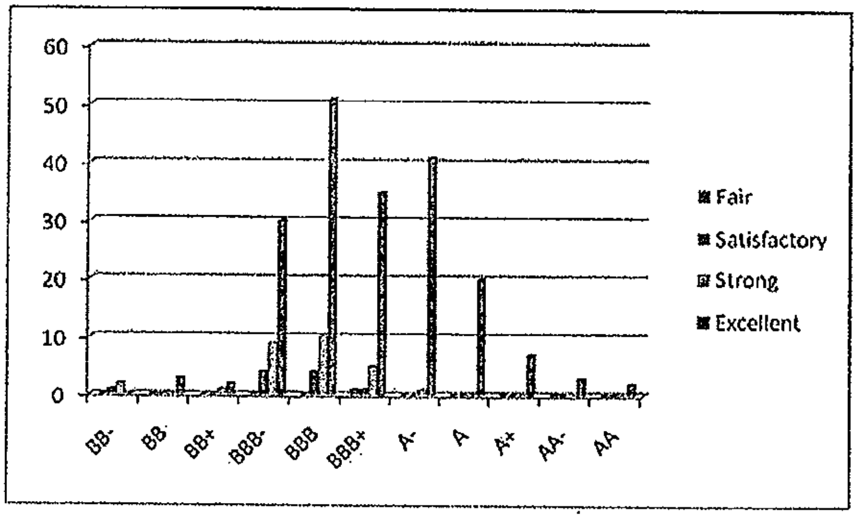
(d) Please confirm that if the economic useful life is reduced and the depreciation rate increased then in the credit metric analysis on pages 55-62 the funds flow to debt and funds flow to interest coverage both increase. Please confirm that, as a result, a riskier utility with a higher depreciation rate has stronger credit metrics using these two measures. If Ms. McShane cannot so confirm, please explain in detail why not.

(e) Please confirm that the credit metrics for the two ratios using funds flow from operations are lower since 2011 partly because of the reduction in the depreciation rate from 6% to 5% (page 60).

(f) Please provide all the underlying data supporting the calculations on page 62 and a detailed explanation of the 10% increase in debt levels as indicated by point 6 on page 60. Please indicate whether DBRS and Moody's make a similar 10% adjustment and provide supporting documentation.

(g) Please provide the DBRS bond rating for CU Inc. for each year since the 2004 Alberta Generic Cost of Capital Decision along with the bond rating since 2004 for the private sector utilities that Ms. McShane would regard as the peer group for the ATCO utilities.

(h) In 2010, in an Enbridge Line 9 hearing before the NEB, Ms. McShane provided the bond ratings for the universe of US regulated utilities with the following graph. Please provide a similar graph using current data. Given Ms. McShane's use of Canadian and US utilities in making her ROE and common equity ratio recommendations, please comment on why CU Inc. would wish to maintain a higher credit rating than its US peer group.



(i) Please provide the common equity ratios in Schedule 5 for investor owned utilities only, not those provincially or municipally owned, along with their regulated common equity ratios.

Response:

(a) Not confirmed. On page 54, Ms. McShane references Section V , pages 16-28, in which she reviewed changes in economic and capital market conditions since the oral portion of the 2011 GCOC proceeding. Based on that analysis, which included, but was not limited to, an analysis of credit spreads, in conjunction with McShane's agreement with the statement by the AUC in *Decision 2009-216* cited on page 54 of her evidence, Ms. McShane concluded that those considerations **alone** warranted reaffirmation of the 2% increase in equity ratios. Business risk and credit metrics considerations discussed subsequent to page 54 support not only a reaffirmation of the 2% but an increase in the equity ratios.

(b) The following table shows a summary of the longest maturity debentures issued by CU Inc. in each year since 2000 (all rates are as at the time of issuance):

Date Issued	Principal Amount (millions)	Term (years)	Maturity	Underlying Canada Bond Rate	Credit Spread	All-in Rate
May 16, 2000	$100	11	June 1, 2011	6.289%	0.76%	7.050%
November 6, 2001	$175	5	November 6, 2006	4.299%	0.55%	4.840%
November 22, 2002	$150	15	November 22, 2017	5.275%	0.87%	6.145%
November 20, 2004	$200	30	November 20, 2034	4.996%	0.90%	5.896%
November 21, 2005	$185	30	November 21, 2035	4.293%	0.89%	5.183%
November 20, 2006	$160	30	November 20, 2036	4.122%	0.91%	5.032%
November 1, 2007	$220	30	October 30, 2037	4.396%	1.16%	5.556%
May 26, 2008	$200	30	May 26, 2038	4.100%	1.48%	5.580%
March 6, 2009	$150	30	March 7, 2039	3.750%	2.75%	6.500%
November 18, 2010	$125	40	November 18, 2050	3.687%	1.26%	4.947%
October 24, 2011	$200	50	October 24, 2061	2.943%	1.65%	4.593%
September 10, 2012	$200	50	September 11, 2062	2.335%	1.49%	3.825%
September 18, 2013	$75	50	September 18, 2063	3.255%	1.60%	4.855%

(c) Yes, it is a tool available to regulators. Confirmed that the NEB lowered the useful economic life of TCPL in RH-1-2002.

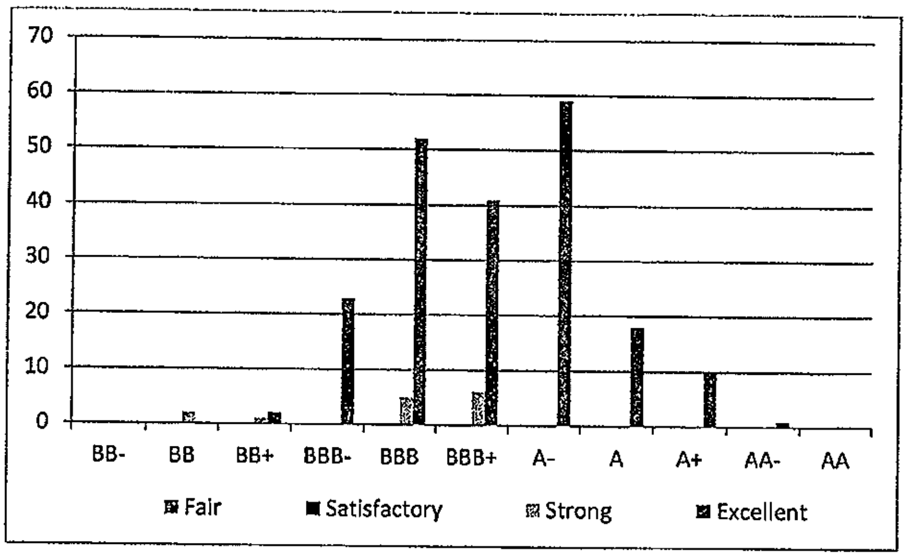
(d) Yes, all other things equal, a higher depreciation rate will result in higher cash flow credit metrics for a utility. All other things equal, a riskier utility with a higher depreciation rate will have stronger credit metrics than a less risky utility with a lower depreciation rate. It bears noting that higher business risk utilities are required to have stronger credit metrics than lower business risk utilities in order to maintain the same debt rating.

(e) Confirmed.

(f) The model used by Ms. McShane to generate the credit metric ratios presented in table 8 on page 60 was provided in response to UCA-AU 12d. The referenced 10% increase in debt is Ms. McShane's estimate of the percentage increase in debt resulting from analytical adjustments made by S&P to reported debt. With respect to DBRS and Moody's, please see response to UCA-AU 13.

(g) CU Inc. has been rated A(high) by DBRS since 2000. The history of the DBRS ratings for a group of private Canadian utilities since 2004 which can be considered peers is attached as CAPP-Utilities McShane 8(g) Attachment 1. DBRS does not rate U.S. utilities. The S&P and Moody's ratings of the U.S. benchmark sample of utility companies, both holding companies and operating subsidiaries, was provided in Ms. McShane's Schedule 7, page 3 of 3. An update of the ratings is provided in CAPP-Utilities McShane 8(g) Attachment 2.

(h) The updated chart is below:



CU Inc.'s ability to maintain a slightly higher rating (one notch by both DBRS and S&P) than its peers is at least in part due to the diversity of its utility operations. It would want to maintain those ratings because of the cost benefits that accrue to the ratepayers of the individual ATCO Utilities.

(i) CAPP-Utilities McShane 8(i) Attachment 1 is Ms. McShane's Schedule 5 with the investor-owned utilities highlighted. The regulated common equity ratios of the investor owned utilities are on Schedule 3.