APPENDIX E

CAPITAL STRUCTURE AND ADJUSTMENTS FOR BUSINESS RISK

To set fair and reasonable rates the Regie needs to set both a fair ROE and a fair capital structure for HQD and HQT (common equity ratio). In this appendix I discuss how the Regie can determine the capital structure for HQT and HQD such that they can both receive the same allowed ROE via my recommended ROE adjustment mechanism.

I: Regulatory Tools for Managing Risk

Investors are interested in the rate of return on the market value of their investment. This investment can be represented by the standard discounted cash flow model:

$$P_0 = \frac{ROE * BVPS * (1-b)}{(K-g)} \qquad (1)$$

where P_0 is the stock price, *ROE* the return on equity, *BVPS* the book value per share, *b* the retention rate (how much of the firm's earnings are ploughed back in investment) and *K* and *g* are the investor's required rate of return and growth expectation respectively.

The discounted cash flow (DCF) model[1] is useful for thinking of the sources of risk to the investor. Some of these risks stem from the firm's operations and financing and others come from the capital market's perception of the firm and general capital market conditions. For regulated utilities we also add another dimension, which is the impact of *regulatory* risk. In terms of the DCF equation the actual earned return on equity **(ROE)** captures the business, financial and regulatory risk, which together I term ***income*** risk, whereas all the other factors are reflected in ***investment*** risk, which is the way in which investors react to the income risk and other variables such as the firm's growth prospects and exposure to interest rates.

Business risk is the risk that originates from the firm's underlying "real" operations. These risks are the typical risks stemming from uncertainty in the demand for the firm's

[1] See Appendix D for a discussion of the basic DCF model.

product resulting, for example, from changes in the economy, the actions of competitors, and the possibility of product obsolescence. This demand uncertainty is compounded by the method of production used by the firm and the uncertainty in the firm's cost structure, caused, for example, by uncertain input costs, like those for labour or critical raw or semi-manufactured materials. Business risk, to a greater or lesser degree, is borne by **all** the investors in the firm. In terms of the firm's income statement, business risk is the risk involved in the firm's earnings before interest and taxes (EBIT). It is the EBIT, which is available to pay the claims that arise from all the invested capital of the firm, that is, the preferred and common equity, the long term debt, and any short term debt such as debt currently due, bank debt and commercial paper.

If the firm has no debt or preferred shares, the common stock holders "own" the EBIT, after payment of corporate taxes, which is the firm's net income. This amount divided by the funds committed by the equity holders (shareholder's equity) is defined to be the firm's return on invested capital or ROI, and reflects the firm's operating performance, independent of financing effects. For 100% equity financed firms, this ROI is also their return on equity (ROE), since by definition the entire capital investment has been provided by the equity holders. The uncertainty attached to the ROI therefore reflects all the risks prior to the effects of the firm's financing and is commonly used to measure the business risk of the firm.

As the firm reduces the amount of equity financing and replaces it with debt or preferred shares, two effects are at work: first the earnings to the common stock holder are reduced as interest and preferred dividends are deducted from EBIT and, second the reduced earnings are spread over a smaller investment. The result of these two effects is called financial leverage. The basic equation[2] is as follows:

$$ROE = ROI + [ROI - R_d(1-T)]\frac{D}{S}$$

[2] Note this equation captures how the actual ROE varies with operating profits. It does not show how the investors required rate of return varies with financial leverage. This requires a valuation model to understand how debt tax shields for example affect value.

where D, and S are the amounts of debt, and equity respectively, T is the corporate tax rate and R_d is the embedded debt cost. If the firm has no debt financing (D/S =0), the return to the common stockholders (ROE) is the same as the return on investment (ROI). In this case, the equity holders are only exposed to business risk. As the debt equity ratio increases, the spread between what the firm earns and its borrowing costs is magnified. This magnification is called financial leverage and measures the ***financial risk*** of the firm.

The common stockholders in valuing the firm are concerned about the total "income" risk they have to bear, which is the variability in the ROE. This reflects both the underlying business risk as well as the added financial risk. If the firm operates in a highly risky business, the normal advice is to primarily finance with equity, otherwise the resulting increase in financial risk might force the firm into serious financial problems. Conversely, if there is very little business risk, as is the case with most regulated utilities, the firm can afford to carry large amounts of debt financing, since there is very little risk to magnify in the first place.

This means that the Regie has a variety of tools to manage the regulated firm's risk. The **first** tool is that it can set up deferral accounts to capture different components of business risk. The essence of deferral accounts is simply to capture forecasting errors. For example, if the operating and maintenance expense is 2% higher than forecast, rather than have the utility's stockholders "eat" the extra costs in terms of a lower earned rate of return, the Regie can simply have the extra costs captured in a deferral account and then, subject to a standard prudency review, charged to the following years' ratepayers. In this way "ratepayers" always pay the full cost of service and stockholder risk is lowered Deferral accounts are very useful when management cannot control or accurately forecast costs and the ratepayer group is fairly stable.

A **second** tool is for the regulator to alter the amount of debt financing. If the regulator feels that the firm's business risk has increased (decreased) it can reduce (increase) the amount of debt financing so that the total risk to the common stockholder is the same. Both of Canada's national regulators, the National Energy Board and the CRTC, have recognized this as has the Alberta Utilities Commission. When the CRTC opened up Canada's telecommunications market to long distance competition it specifically increased the allowed common equity component of the Telcos to 55% to offset the increased business risk. Similarly, when the NEB decided to go to a formula based approach for the return on equity it reviewed all the capital structure ratios for the major oil and gas pipelines and set different equity ratios for the firms that it believed faced different business risks. The NEB specifically stated (RH-2-94, page 24)

> *"The Board is of the view that the determination of a pipeline's capital structure starts with an analysis of its business risk. This approach takes root in financial theory and has been supported by the expert witnesses in this hearing. Other factors such as financing requirements, the pipeline's size and its ability to access various financial markets are also given some weight in order to portray, as accurately as possible, a complete picture of the risks facing a pipeline* "

TransCanada, for example, was allowed 30% common equity[3], since it predominantly had mainline transmission operations, while Westcoast with its greater proportion of gathering and processing lines was allowed 35% and the oil pipelines 45%, due in part to the constant change in the mix of fluids going down the pipeline. Once the financial risk had offset the different business risks, the NEB was able to award them all the same return on equity.

The AUC in 2003 (Decision 2004-052, page 55) had to review a variety of utilities in different areas and it decided to adjust their capital structures to offset what it perceived to be different business risk profiles and then allow them all the same ROE through its adjustment mechanism. In the AUC decision electric transmission was the lowest risk regulated utility at 33% common equity plus an additional 2% for non-taxable entities, then gas transmission (NGTL) at 35%, electric distribution at 37% and gas distribution at 38%. The AUC has reviewed these ratios subsequently and is about to review them again since in 2009 it allowed a surcharge on the common equity ratios of 1.0-2.0% to account for the financial crisis. However, the basic risk ranking remained the same.

[3] The NEB has progressively increased the TransCanada Mainline's common equity ratio from 30% to 33%, then 36% and finally 40% in view of the increased throughput risk on the Mainline..

Table 1. Board Approved Equity Ratios

	Last Board-Approved Common Equity Ratios (%)	2004 Board Approved Common Equity Ratios (%)	Change in Approved Common Equity Ratio (%)
ATCO TFO	32.0	33.0	1.0
AltaLink	34.0	35.0	1.0
EPCOR TFO	35.0	35.0	0.0
NGTL	32.0	35.0	3.0
ATCO Electric DISCO	35.0	37.0	2.0
FortisAlberta (Aquila)	N/A	37.0	N/A
ATCO Gas	37.0	38.0	1.0
ENMAX DISCO	N/A	39.0	N/A
EPCOR DISCO	N/A	39.0	N/A
AltaGas	41.0	41.0	0.0
ATCO Pipelines	43.5	43.0	(0.5)

The **third** tool available for the regulator is to directly alter the allowed rate of return, so that the stockholder only earns a rate of return commensurate with the risks undertaken. The CRTC, for example, has historically allowed Northwestel 0.75% more than the other Telcos primarily due to the "ruggedness" of its operating region. Similarly the Ontario Energy Board routinely allowed Union Gas slightly more than EGDI (Consumers Gas). Although in 2012 this policy seemed to slip since both companies had their common equity ratios confirmed at 36%, but now get the same allowed ROE through the OEB formula. Finally some boards adjust both the common equity ratio and the allowed ROE. The BCUC does this in setting the benchmark utility as Fortis Energy Inc (FEI) and then having both a premium to the ROE and common equity ratio for other utilities such as Pacific Northern Gas. In all cases, whether it is more common equity or a higher ROE, the utility has more net income.

2: Recommended Risk Management Policies

Generally for regulated utilities setting up deferral accounts for hard to control items imposes negligible risk to ratepayers and significant reductions in risk for the utility. As a result, deferral accounts are a "win-win" for both ratepayers and shareholders. Consequently, I have testified before most regulatory boards that the use of deferral accounts to manage the cost of short term debt, the impact of weather related demand fluctuation and other items over which management has no control is the first risk management tool that should be used.

With a choice between capital structure versus ROE adjustments, my preference is to adjust capital structures for three main reasons. *First*, the market seems to consider any changes in the allowed capital structure to be a more permanent change, while it expects the ROE to change with capital market conditions. Since business risk is the primary determinant of capital structure, it is to be expected that a board will change an allowed capital structure relatively infrequently in response to changes in business risk. *Second*, fixing capital structures reduces the amount of testimony that Boards hear and as a result regulatory costs. The Board can then set the allowed equity ratios relatively infrequently and use an adjustment mechanism to set the ROE. This allows a Board to focus on major issues like performance based regulation and negotiated settlements, rather than frequently repetitive capital structure and ROE testimony. *Finally*, allowing firms to chose their capital structure and then adjusting the ROE to a fair return runs the risk that although the equity holders are getting a fair rate of return the overall utility income and thus rates are too high and unfair.

This latter point is very important, since the firm's capital structure has a direct impact on its overall cost of capital, as certain types of financial instruments have a tax-preferred status. In Canada this status is accorded to debt, since interest payments are tax deductible, whereas equity dividends are not. As a result, there is a built-in tax advantage to any corporation using debt financing. This tax advantage goes to the ***shareholders*** of ***unregulated*** firms but to the ***customers*** of ***regulated*** firms. This is because the use of debt reduces the regulated firm's revenue requirement.

The above discussion is needed to put the utility capital structure in perspective, since regulated utilities have the lowest business risk of just about any sector in the Canadian economy. Consequently, they should have the highest debt ratios. There are several reasons for this:

> **First**, a full "cost of service" regulated utility like a pipeline has *no* variation in its operating income. As such financial leverage is magnifying non-existent business risk, and zero times anything is still zero! Even for companies on a forward test year the use of deferral accounts means that there is minimal variation in its operating income from that

allowed. This is why the TransCanada Mainline, for example from 1994 to 2001 was allowed the same equity ratio as a full cost of service pipeline like Foothills.

Second, in the event of unanticipated risks, regulated utilities are the **only** group that can go back to their regulator and ask for "after the fact" rate relief. As regulated utilities their rates can be increased in the event of financial problems, while demand is typically insensitive to these rate increases. In contrast, if non-regulated firms face serious financial problems they usually compound one another. This is because unregulated firms encounter difficulties raising capital and frequently suppliers and customers switch to alternates in the face of this uncertainty creating severe financial distress.

Third, the major offset to the tax advantages of debt is the risk of bankruptcy. In liquidation there are significant external costs that go to neither the equity nor the debt holders. These costs include "knock down" asset sales, the loss of tax loss carry forwards, and the reorganisation costs paid to bankruptcy trustees, lawyers etc. This causes non-regulated firms to be wary of taking on too much debt, since value seeps out of the firm as a whole. In contrast it is inconceivable that an electric transmission grid like HQT could see their assets ripped up and sold for scrap. Before that happened the commodity on which these assets rely, that is, electricity, would have to face a melt down.

Finally, most private companies have an asset base that consists largely of intangible assets. For example, the major value of RIM was its brand and growth opportunities (!), of Coca Cola its brand name, of Merck its R&D team. It is extremely difficult for non-regulated firms to borrow against these assets. Growth opportunities have a habit of being competed away, brand names can waste away, while R&D teams have a habit of moving to a competitor as RIM has found out the hard way. Regulated utilities on the other hand largely produce un-branded services and derive most of their value from tangible assets. Unlike intangible assets, tangible assets are useful for collateral, for example in first mortgage bonds, and are easy to borrow against.

Consequently utilities have very low business risk, have reserve borrowing power by returning to the regulator, minuscule bankruptcy/distress costs and hard tangible assets that are easy to borrow against. In fact, in many ways, utilities are unique in terms of their financing possibilities,[4] and are prime candidates for using large amounts of debt to finance their operations.

3: Business Risk Rankings in 2003

The risks faced by the stockholder in the DCF equation (1) can be divided into short and long term risks. The short term risks are essentially the ability of the regulated firm to earn its allowed ROE, which is what I previously termed income risk, while long term

[4] When we analyse corporate financial decisions we normally include a number of explanatory variables and then add a "dummy" variable for whether or not the industry is regulated, since the mere fact of regulation is frequently the most significant feature of a firm's operations.

risks refer to the growth in these future cash flows and the risk of not being able to recover the capital invested.

The major short term risks stem from both cost and revenue uncertainty.

- On the cost side since regulated utilities are capital intensive most of their costs are fixed. The major risks are in *operations and maintenance* expenditures. However, over runs are usually under the control of the regulated firm and can be time shifted between different test years.

- On the revenue side the risks largely stem from rate design: critical features are:

    - Who is the customer and what *credit risk* is involved. For example, electricity transmission operators who recover their revenue requirement in fixed monthly payments, have less exposure than the local gas and electricity distributors who recover their revenue requirement from a more varied customer mix involving industrial, commercial and retail customers.

    - Is there a *commodity charge* involved? The basic distribution function is very similar to transmission, except when the distributor buys the gas or electricity wholesale and then also retails the commodity. The distributor is then exposed to weather and price fluctuations depending on rate design.

    - Even if there is no commodity charge, how much of the revenue is recovered in a *fixed versus a variable usage* charge? Utilities that recover their revenue in a fixed demand charge face less risk than those where the revenues have a variable component based on usage.

The above risks are all moderated by whether or not the Board allows deferral accounts.

The medium and long term risks are mainly as follows:

- *Bypass risk*. The economics of regulated industries are as natural monopolists involved in "transportation" of one kind or another. However, one utility may not own all the transportation system so that it may be economically feasible to bypass one part of the system. This happens for local gas distributors, when a customer can access the main gas transmission line directly, rather than through the LDC, or when a large customer may be able to bypass part of the transmission system. This is largely a rate design issue: a postage stamp toll clearly leads to uneconomic tolls and potential bypass problems, whereas distance or usage sensitive tolls will discourage it. Similarly, rolled in tolling will encourage predatory pricing by potential regulated competitors.

- *Capital recovery* risk. Since most utilities are transportation utilities, the critical question is the underlying supply and demand of the commodity. If supply or demand does not materialise then tolls may have to rise and the utility may not be able to recover the cost of its capital assets. Depreciation rates are set to mitigate this risk to ensure that the future revenues are matched with the future costs of the system.

A common thread running through the above brief discussion of utility risks is rate design and regulatory protection. There can be significant differences in underlying business risk that are moderated by the regulator in response to those differences. The lowest risk utility is then one with the strongest underlying fundamentals and the least need to resort to regulatory protection. In contrast, another utility may have similar short term income risk, but only because of its need to resort to more extensive regulatory protection, so that it faces more problematic longer term risks.

In 2003 this analysis led me to the following conclusions in the Alberta Generic hearing

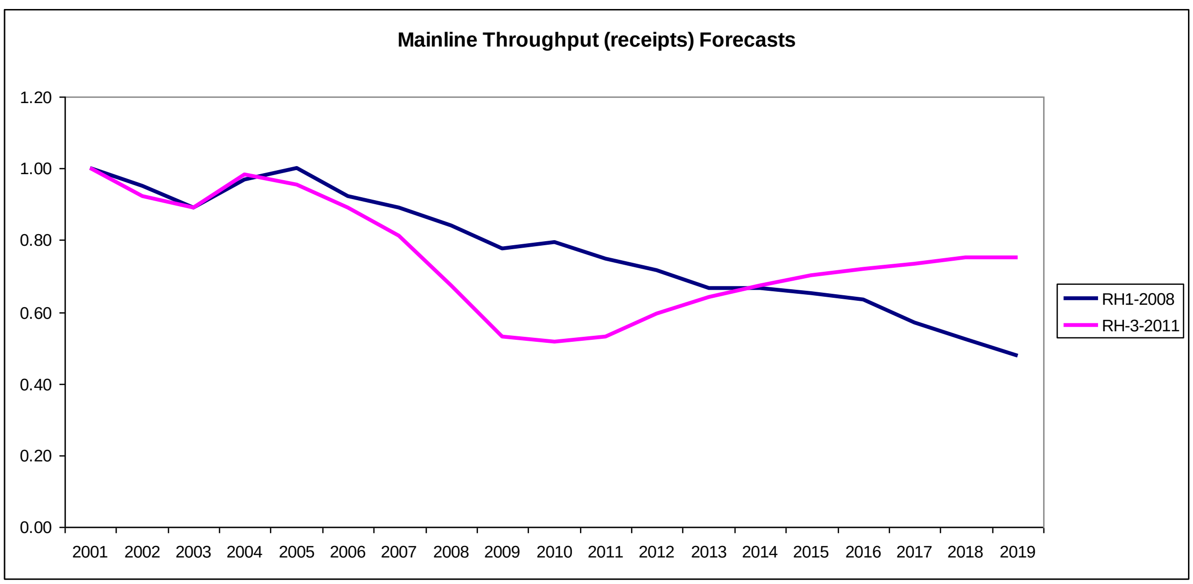
> ***Consequently, I recommend the following common equity ratios:***
>
> ***Lowest risk:*** ***Electricity transmission assets, for example AltaLink, 30%***
>
> ***Very low risk:*** ***Gas transmission assets, for example NGTL, 33%***
>
> ***Average risk:*** ***Gas and Electric LDCs, for example, ATCO Gas 35%***
>
> ***Above average risk:*** ***ATCO Pipelines 36-42%, (depends on 2004 EUB decision)***
>
> ***In my judgement, none of the Alberta utilities are as risky as Pacific Northern Gas (PNG) or Gaz Metropolitain (GMI).***

Although the AUC implemented slightly different common equity ratios to the ones that I recommended the risk ranking was essentially identical to mine. However, the critical point is that the AUC adopted different common equity ratios to offset differences in business risk. It is absolutely incorrect to then use these higher debt ratios, for electricity transmission. for example, and imply that there is greater financial risk and thus a need for a higher ROE. This ignores the fact that the higher debt ratio (lower common equity ratio) was set because of the lower business risk and with the specific objective of equalising the overall risk, so that the same ROE ***can*** be applied. Failing to understand this basic point implies a failure to understand and how regulation in practise works in Canada.

4: Changes in Business Risk Rankings since 2003

It is frequently difficult to update business risk rankings since much of the specific utility information comes not out of generic hearings but the detailed examination involved in a general rate application. However, since 2003, the major change has been in the gas transmission business, since the emergence of new supply pools has endangered 'point to point' gas pipelines like the TransCanada Mainline to such an extent that TransCanada is discussing changing one of the Mainline's pipes to carry oil instead of natural gas. Further in a major hearing in 2012 the National Energy Board allowed the Mainline (RH-003-2011) considerable discretion in managing its throughput as well as increasing its allowed ROE, a position I supported.

The following graph shows the Mainline's throughput forecast out to 2020 in RH-1-2008 (The TQM hearing) and RH-3-2011, the 2011/12 TransCanada Mainline hearing. In both cases the throughput is based on TransCanada's supply forecast and inititialised to 1.0 in 2001.



Clearly a 50% drop in throughput from 2001 to 2010 has seriously impacted the Mainline's business risk since it has raised the spectre of a "death spiral" as throughput drops off the revenue requirement is the same, so tolls are increased for the remaining customers causing them to rethink the use of the Mainline.

Because of the problems with the TransCanada Mainline I would now judge it to be one of the riskiest utilities in Canada. However, this assessment does not include either NGTL or other export pipelines that have not suffered the same loss in load, since they serve different markets where customer needs can be met by alternative supply basins.

I have also recently been involved in three hearings into the business risk of natural gas distribution utilities. In all three I recommended a 35% common equity ratio. In the 2012 Union Gas and Enbridge Gas Distribution Inc (EGDI) hearings in Ontario, the OEB maintained the existing 36% common equity ratio despite company testimony that gas distributors were riskier than electric distributors and requests for 40-42% common equity. In its Union Gas decision the OEB stated (Decision EB 2011-0210)

> ***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.***

The OEB also rejected comparisons with other utilities both in Canada and the US since there was no analysis to confirm that the business risks were in fact the same.

In its decision on EGDI the OEB was faced with evidence from both Dr. Coyne and myself (EB-2011-0354)). Dr. Coyne claimed that EGDI warranted a 42% common equity ratio to meet the fair return standard (FRS). The OEB emphatically rejected this claim stating,

> ***This interpretation of the Board's policy is incorrect. The Board states explicitly in the Cost of Capital Report that the current policy on capital structure continues to***

be appropriate and that capital structure will only be reviewed if there is a significant change in risk for the specific company. This does not entail a full cost of capital analysis and assessment against the FRS unless there has been a significant change in risk. The Board has structured its policy in a way that applies the FRS while promoting regulatory efficiency and predictability. The Board's policy does not require a full FRS analysis in each rate case. However, it ensures that the Board will perform a full review of capital structure in instances where a significant change in risk indicates that a change may be needed in order to continue to meet the FRS. The Board considers that where there has not been a significant change in risk, the FRS continues to be met. The Board notes that another Enbridge witness, Mr. Lister, expressed this as Enbridge's understanding as well: "It is our position that if the Board found that there was no change in business risk, then by definition the Board would be saying that the fair return standard has been met."

Accordingly the OEB decision was

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.

In the BCUC hearing (Decision G-20-12) the BCUC considered a variety of risk factors that face FEI (formerly BC Gas) and what had changed since the last time the BCUC considered its business risk in 2009 and decided (Decision page 54)

The Commission Panel has examined the factors contributing to long-term risk in this proceeding and considered the submissions of each of the parties. The Panel has found that reductions are warranted in long-term risk associated with provincial government climate and energy policies as well as the competitive position of natural gas relative to electricity. Both of these risk areas were rated by the FBCU as category 2 risks. To offset these there is not a single area where the Panel has been persuaded the level of long-term risk has been demonstrated to have increased materially since 2009........

Consideration being given to both long and short-term risk, the Commission Panel determines that a reduction in the common equity ratio of 1.5 percent to 38.5 percent is appropriate.

The conclusions I draw from these recent decisions are twofold. First, they confirm that the appropriate base for determining a capital structure change is a change in the business risk faced by the utility since the last decision order. Second, while there has been a demonstrable increase in the risk facing the TransCanada Mainline, that has seen its common equity ratio increase from 30% to 40%, there has been no material change in the business risk of natural gas distribution utilities. Both Union Gas and EGDI had their 36% common equity ratio confirmed. FEI had theirs decreased by 1.50%, but it seems to be mainly due to climate change regulation in BC, since both Union and EGDI faced similar increases in their competitive position relative to competing fuels.

Finally I would point out that the Regie itself has maintained Gaz Metro's common equity ratio at 38.5% plus 7.5% deemed preferred shares. This assessment was confirmed in D-2009-156 when the Regie decided that this risk had not materially changed since 2007. (D-2009156, paragraphs 278-282). So I see no material differences between the policy of the Regie and that of the OEB, BCUC and NEB.

5: The business Risk of HQT and HQD.

I have discussed the business risk of HQD and HQT with Olivier Charest, reviewed the fling information and previous testimony by Dr. El-Ramly (R34-1-98) and Drs. Kryzanoski and Roberts (R-3492-2002). The judgment of Mr. Charest is that there has been no increase in risk for either HQT or HQD, in fact he concludes that this risk has decreased. What is important is that in the few pages of analysis by HQ (pages 9-12), while there is a discussion of absolute risk, there is no discussion of whether any of these risks are materially different from 2002/3 when the common equity ratios were last set. Further in the testimony provided by Dr. Coyne while he attempts to show that HQD and HQT are similar in risk to a US proxy sample there is no material discussion as to whether these risks have changed since 2002/3.[5] This is the evidentiary basis for a change in business risk that Dr. Coyne's testimony seemed to fail to meet before the OEB

The short run risk facing HQT and HQD are essentially whether they can consistently earn their allowed ROE. Given frequent rate cases, this essentially revolves around the use of deferral accounts to capture short run deviations of revenues and costs from those

[5] Dr. Coyne does mention the increased competitive position of natural gas, but as I will show in Quebec this is somewhat moot as far as HQ is concerned.

included in the revenue requirement. Here my assessment is guided by the history of both divisions since 2007 and Answer 13 to information requests from the Regie, where HQT and HQD have over earned as follows:

	2007	2008	2009	2010	2011	2012
HQT	-63.4	31.7	83.6	87.9	66.9	152.0
HQD	9.4	26.6	105.7	171.4	101.2	111.4

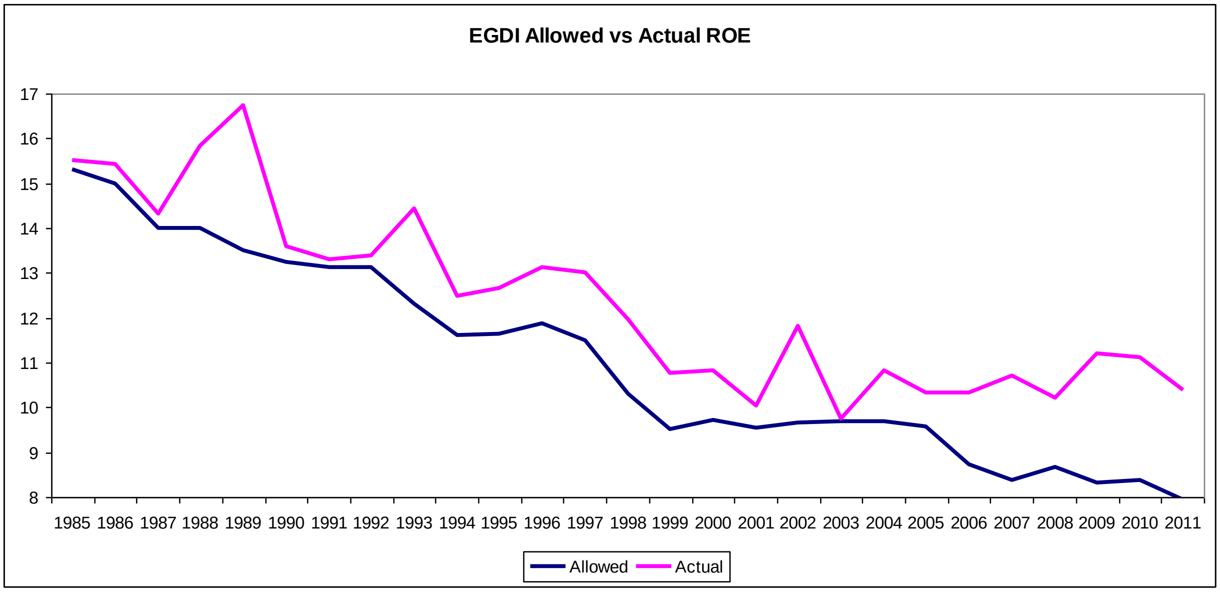
In the case of HQT the major deviations from the amounts in the revenue requirement are due to operations and maintenance (O&M) expense and depreciation and amortisation (D&A) except for 2007 where the insufficiency mainly stemmed from additional debt service costs. The deviation of D&A from forecast comes from a change in the economic useful life assumption or changes in plant coming into service. *However in total over this period there is a history of over-earning and in total HQT exceeded its allowed net income by $458.7 million. While its allowed ROE I would judge to have been lower than for other Canadian utilities, it is clear that HQT has not suffered any material loss in the sense of failing to earn its allowed ROE*

In the case of HQD the overall amount of over earning was $525.7 million with not one year where the actual earnings were less than those allowed. Again the main areas are O&M and D&A, plus in the case of HQD additional variance caused by the volumetric component in the rate structure.[6] *Normally this is the risk that makes distributors slightly more risky than transmission companies, but in the case of HQT customer growth was more than anticipated leading to over earning.*

If business risk is in fact failing to earn the allowed ROE, then neither HQT nor HQD have experienced any material risk, at least since 2008. In this I would admit that HQD and HQT are no different from other Canadian utilities. The regulatory structure for HQT and HQD is not as mature as for some other Canadian utilities, but in EB-2011-0354,

[6] Note persistent over-earning of the magnitude of both HQT and HQD could be part of the adjustment to a more mature regulatory system or an attempt to manipulate the system.

EGDI provided its allowed versus actual ROE back to 1990 and in EB-2006-0034, for 1985-1989. The graph below shows this data for the weather normalised ROE and the allowed ROE.



In not one year since 1985 has EGDI failed to earn its allowed ROE on a weather normalised basis. Consistent with the assessment of DBRS and S&P the only fluctuation from the allowed ROE has been caused by random weather fluctuation. On a factual basis EGDI has yet to record ***any*** risk that has harmed its shareholders in the last ***27*** years, despite expert testimony and company evidence that has testified to "increased risks" in various hearings. Further of note is that EGDI has recently been under a five year incentive plan and quite obviously its degree of over-earning has dramatically increased, indicating that so far PBR or settlements have posed no increased risk to a Canadian utility.

One reason for the low risk of Canadian utilities is the full set of deferral accounts that they have available to them. However, even when there are no deferral accounts, the utility still has the right to go back to the regulator and have any losses reassigned to ratepayers. This is the regulatory dynamic in Canada. EGDI, for example, came before the OEB to deal with a potential liability caused by the Supreme Court of Canada with respect to late payment penalties and a July 20, 2006 settlement. On page 3 of the October 31, 2006 MD&A EGDI simply stated

> "The company intends to apply to the OEB for recovery of the proposed payments resulting from the settlement of this action."

Interveners did not prevent the recovery of these costs from ratepayers. The major inference is that this was a "risk" not borne by the company or its shareholders, but was in fact transferred to the ratepayers.

A further example for EGDI stems from the fact that its S&P credit rating is largely a flow through from that of its parent EI. However, EGDI was asked to confirm that it would ***not*** ask for any higher debt costs to be passed on to EGDI's Ontario ratepayers if S&P downgraded EGDI due to the introduction of a competitive tolling system on its parent's pipeline System, that is, problems caused by Enbridge Pipeline and nothing to do with EGDI or its Ontario customers. Surprisingly, EGDI boldly stated:

> "Not confirmed. If EGD's credit rating is downgraded, EGD will seek relief at the earliest possible opportunity."

Sometimes it is very difficult to find out exactly what costs are borne by shareholders when evaluating the actual way in which the regulatory dynamic operates in Canada.

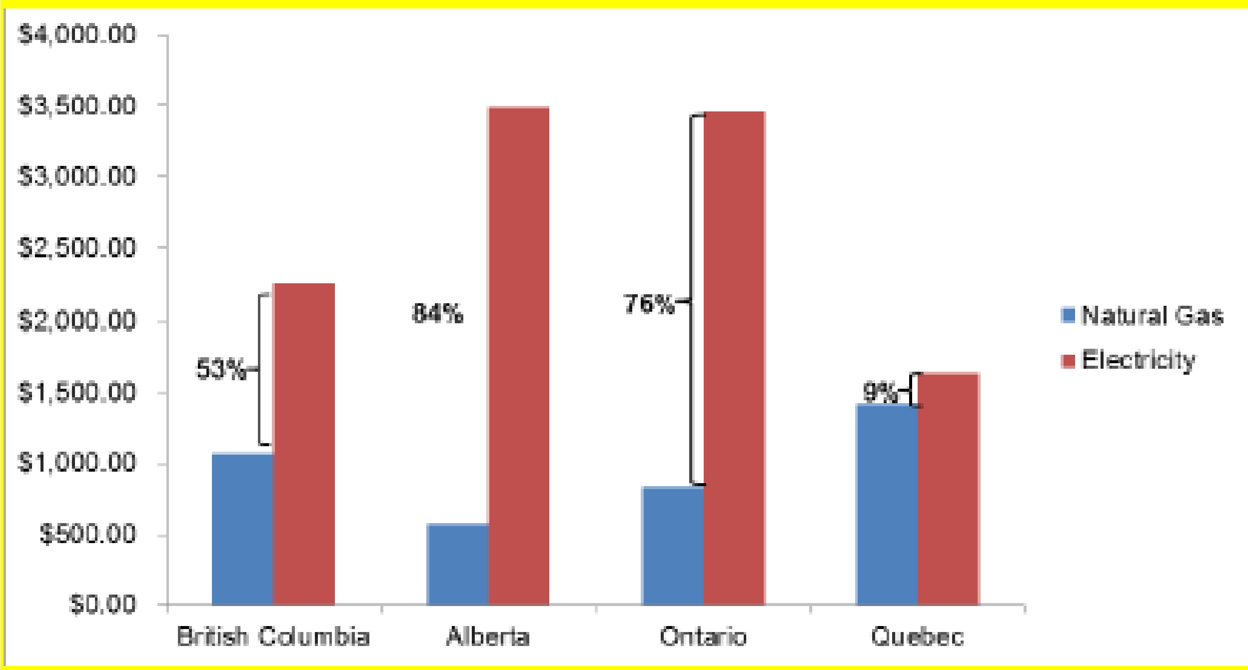
To understand how this regulatory dynamic works in Canada, it is important to realise that frequent rate hearings and close supervision by the regulator serve to lower risk. Deferral accounts, for example, are not very effective if there are no rate hearings to approve their disposition in future tolls. If a utility suffers significant regulatory lag or is on an historic test year then this generally increases its risk. The following is from AUS utility reports (September 2013). What is striking is that for several utilities AUS does not report the order date establishing the allowed ROE, while for others the allowed ROE has not changed for years.

	REGULATION	
	ALLOWED ROE	ORDER DATE
ALLETE, Inc. (NYSE-ALE)	10.38	11/10
American Electric Power Co. (NYSE-AEP)	10.63	-
Cleco Corporation (NYSE-CNL)	10.70	10/09
Edison International (NYSE-EIX)	10.63	-
El Paso Electric Company (NYSE-EE)	11.25	-
FirstEnergy Corporation (ASE-FE)	10.52	-
Great Plains Energy Incorporated (NYSE-GXP)	10.12	-
Hawaiian Electric Industries, Inc. (NYSE-HE)	9.67	-
IDACORP, Inc. (NYSE-IDA)	10.18	05/09
Nextera Energy (NYSE-NEE)	10.50	03/10
OGE Energy Corp. (NYSE-OGE)	9.98	-
Otter Tail Corporation (NDQ-OTTR)	10.75	-
Pinnacle West Capital Corp. (NYSE-PNW)	11.00	12/09
PNM Resources, Inc. (NYSE-PNM)	10.22	-
Portland General Electric Company (NYSE-POR)	10.00	12/10
PPL Corporation (NYSE-PPL)	10.35	-
Southern Company (NYSE-SO)	11.46	-
Westar Energy, Inc. (NYSE-WR)	10.20	12/05
AVERAGE	10.47	

Longer term the risk of a utility stems from the underlying supply and demand for the product it distributes. Here two factors are primary. The first is that the resource backing both the transmission and the distribution system is HQP and here the useful life for HQP's dams I am informed in some cases is over 100 years. A system distributing such a long lived low risk supply is of necessity low risk. The second fact is the competitive nature of the supply.

In last year's BCUC hearing FEI provided the following data in answer to BCUC IR#1-101.2

Natural Gas versus Electrcity based on 100 GJ's:



In the BCUC hearing the assessment was how competitive natural gas is relative to its fuel competitor: electricity. The normal comparators for FEI are the two big natural gas distributors in Ontario, ATCO Gas in Alberta and Gaz Metro. Here it is important to understand that gas is mainly used for space heating, whereas electricity has many uses outside of space heating such as street lights, computers etc. So if natural gas loses its competitive advantage it may lose the bulk of its market, whereas electricity will still have a very large monopoly element of demand.

Clearly the above graph indicates that the low risk gas distributors are those in Alberta and Ontario where electricity is quite expensive. In contrast, both BC Hydro and HQ derive the bulk of their supply from low cost hydro instead of coal, natural gas, or nuclear. As a result, FEI is slightly riskier than the Ontario utilities and Atco Gas but less risky than Gaz Metro. The Regie has recognised this in its decision that Gaz Metro is above average risk since HQ is a formidable competitor as the above data demonstrates and electricity is the fuel of choice for residential customers in much of Montreal, while Gaz Metro has more industrial load. Of course if Gaz Metro is more risky, then by definition it means that HQ is less risky than BC Hydro, Hydro One or the Alberta transmission and distribution utilities.

One final reference point is that on October 14, 2013 in a feature article in the Globe and Mail it was stated

> ***Higher electricity rates is one of a growing list of good reasons not to make things in Canada. Already reeling from the high dollar and a host of competitive disadvantages, expensive power risks forcing more businesses out of the province altogether – to Quebec, or more likely, to the United States.***
>
> ***The problem goes way beyond the $1-billion squandered on two cancelled gas-fired power plants……………………………………..***
>
> ***"Ontario is probably the worst electricity market in the world," said Pierre-Olivier Pineau, an associate professor and electricity market expert at the University of Montreal's HEC business school.***
>
> ***Ontario's prices are now dangerously out of whack with key neighbouring jurisdictions, who are using cheap natural gas to produce power. The average price paid by large industrial power users in Toronto is nearly 11 cents per kilowatt hour, according to Hydro-Québec's 2013 survey. That compares with 4.8 cents in Montreal, 5.45 cents in Chicago and 8.12 cents in Detroit.***
>
> ***The Toronto-Montreal price gap has widened to 123 per cent, up from 79 per cent in 2009. Four years ago, power was cheaper in Toronto than Chicago. Now the reverse is true.***

The Quebec government is very well aware of the fact that cheap power is a competitive advantage for the province. Canadian Press reports that the Quebec Government has recently announced a four year jobs plan and states

> ***Premier Pauline Marois says the measures should create 43,000 new jobs at a cost of $2 billion by 2017.***
>
> ***They include $708.8 million in tax credits for businesses, a discount price on surplus hydro used by companies, renovating schools and community centres, and electric-transport projects.***

What is important is that Quebec is utilising its competitive advantage in low cost power to attract industry and jobs. This is a clear indicator of the low risk nature of both HQT and HQD.

In conclusion I would state that HQT and HQD are probably the lowest risk transmission and distribution companies in Canada. With Union Gas and EGDI allowed 36% common equity and the OEB formula allowed ROE I would judge the requested 35% common equity ratio for HQD to be generous, but within a reasonable range. With the Alberta utilities in a fragmented transmission grid without the advantage of being seen as an instrument of provincial government policy I would judge 30% common equity for HQT again to be within a reasonable range.

Of importance is that these common equity ratios already ***reflect*** their low business risk and do not impose any “increased financial risk” on their (government) shareholder. Finally I should point out that this low risk evaluation has nothing to do with the fact that the debt of both HQT and HQD is guaranteed by the provincial government. The low risk nature of these assets reflects the fact they are important to the Province. S&P, for example, would take this implicit support into account and notch up HQ’s debt rating regardless of whether or not that debt is explicitly guaranteed.