IN THE MATTER OF the *Public Utilities Act,* R.S.N.L. 1990, Chapter P-47, as amended (the "Act"); and

IN THE MATTER OF a General Rate Application by Newfoundland Power Inc. to establish customer rates for 2010

To: The Board of Commissioners of Public Utilities (the "Board")

Consumer Advocate's Final Written Submission

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Introductory Comments About Risk

October 14, 2009, the Consumer Advocate made the following observation in his opening statement:

> *"In this general rate application, the key issue is the return on equity and the future of the automatic adjustment formula or mechanism. Newfoundland Power has been and will continue to be a very well protected stable, predictable, conservative, low risk utility operating in a very supportive regulatory environment where the company enjoys moderate, yet fairly steady customer growth, free from any significant competition. With only a small amount of generation, Newfoundland Power is predominantly poles and wires. In essence, it is very low risk."*

This is the utility which we have to keep in mind in assessing the Fair Return. Investors in NP have no right to earn a return on equity commensurate with a utility exposed to greater risks.

NP is risk averse. It has a penchant for mechanisms that transfer risk to the customers. The result is that it is left with next to no risk. Indeed, the foundation of Newfoundland Power's multi-year regime is that it makes generous use of regulatory mechanisms that create cost recovery certainty and therefore reduce the risk to Newfoundland Power.

John Todd observed that *"this low risk environment will ultimately benefit rate payers as well as the company, provided the risk adjusted return on equity that is used in setting rates reflects the lower risk to which the company is exposed and the commensurate higher risk that customers face."* [Reference Oct 27, 2009, p. 2009, p. 76 - 77]

NP's Counsel appeared to suggest that as long as customers were picking up the benefits when costs go down and then picking up the costs when the costs went up - that it is *"not simply just a risk transfer to customers."* To this proposition, Mr. Todd had to explain (p. 93 - 94 of Oct 27, 2009):

> *"A. No, the risk goes two ways. The risk transfer is a transfer of both potential costs and potential benefits. What you're transferring is uncertainty. <u>It is uncertainty that attracts a higher return, a compensation for risk</u>."* (emphasis added)

The point that Mr. Todd was making was further developed by questions from the Board Hearing Counsel, starting at p. 112:

"Mr. Simmons:
Q. Mr. Todd, I've got a few questions for you. First of all, about the multi-year regime, and the concept of risk and how that fits in. First of all, apart from any deferral mechanisms or any of these regulatory mechanisms that you've described, the basic method of setting rates is that the Board will look at the forecast for a test year and set rates based on what the forecasted revenues and expenses are, but that those revenues and expenses when actually incurred by the company may be different, and - - correct?

Mr. Todd:
A. Correct.

Mr. Simmons:
Q. And apart from any mechanisms that are put in place to adjust for variances for those, the company bears the risk of revenues being lower, costs being higher, but stands to reap the benefit of expenses being lower and revenues being higher?

Mr. Todd:
A. Yes, that's using risk in the sense of being negative as opposed to the technical concept of risk and cost of capital discussions where risk means variance in two directions.
Mr. Simmons:
Q. So when you speak of transferring a risk, for example, for the utility to the customers, you're not limiting yourself to those things that might occur that

would hurt the financial bottom line of the company. You're referring to the upside as well as the downside when you say that a risk is passed on?

Mr. Todd:
A. I'm referring to risk in the finance sense.

Mr. Simmons:
Q. Yes.

Mr. Todd:
A. Of the transfer of the uncertainty that there may be higher or lower impacts on the company. When you transfer the risk to the customer, the customer may bear higher or lower costs in the future due to variances.

Mr. Simmons:
Q. Right, so you've also used the term "uncertainty" a little while ago to say that really it's a transfer of the uncertainty about whether the actual revenues and expenses will match the forecast revenues and expenses?

Mr. Todd:
A. Right, and this is - - that's the concept of risk in financial markets where a riskier investment has both greater upside potential and downside possibilities, and the risk that is embedded in a higher return for higher risk relates to the fact that there's more uncertainty that goes in both directions.

Mr. Simmons:
Q. And would it be fair to say that the two principal features of the multi-year regime that's used here in this jurisdiction are the regulatory mechanisms, such as the rate stabilization account, and now the PEVDA, that have the effect of lessening the exposure of the company to those uncertainties about whether actual expenses will match forecast expenses? That's one feature.

Mr. Todd:
A. Yes, and the existence of those types of mechanisms is not unique to this regime. They seem to be used more extensively here.

NP appears to have some difficulty acknowledging that some of its accounts are risk transfer mechanisms. To illustrate, DBRS in its May 5, 2008 Rating Report (Exhibit 4) notes that NP has a weather normalization reserve account that is used to stabilize earnings during extreme weather conditions. That is not the way NP described the WNR in CA-NP-55 (p. 2 of 4). Rather, according to NP:

> *"The Weather Normalization Reserve acts to stabilize electricity rates to customers by adjusting the Company's sales and power supply costs for variations related to hydrology and weather."* (emphasis added)

It is odd that the WNR would be described as acting to *"stabilize electricity rates"* when as was clear from Information No. 5 - [being CA-NP-141 for the 2008 GRA] that the WNR's dollar transfers, in combination with the RSA, has represented up to 11.6% of the Return on Equity of NP in a given year. In 2006 alone, $2.7 million was transferred to the company from customers under this risk transfer mechanism. Customers, not NP, bear the uncertainty - bear the risk.

As suggested in the Board Hearing Counsel's question of Mr. Todd on the previous page, more risk will be transferred to customers with the establishment of the PEVDA. It is submitted that this is a new risk reducer for the company.

It is respectfully submitted that the Board must ensure that customers benefit from the low risk environment that NP operates in. Customers, to a large degree, have assumed risk so that NP can be free of it. Customers can only benefit if the return on equity that is used in setting rates actually reflects the lower risk to which the company is exposed and the commensurate higher risk that customers face.

Fair Return

At the heart of this GRA is the question, *"What is a Fair Return for Newfoundland Power?"*

The Fair Return Principle as explained in P.U. 19 (2003) is as follows:

> **"1. Fair Return**
>
> **Regulated Utilities are given the opportunity to have a fair rate of return. To be considered fair, the return must be:**
> - **commensurate with return on investments of similar risk;**
> - **sufficient to assure financial integrity; and**
> - **sufficient to attract necessary capital.**
>
> **The fair return principle is consistent with both Section 80(1) of the Act and Section 3(iii) of the EPCA."**

NP's Amended Application (p 1-3) has stated that *"In order to sustain Newfoundland Power's financial integrity in current market conditions, the company is targeting a 2010 return on equity of 11%."* This is a gross overstatement of NP's Fair Return, in our respectful submission.

McShane - Overview

Ms. Kathleen McShane in her report estimated utility costs of equity based on three equity risk premium methodologies as shown in Table 10

Risk Premium Test	Cost of Equity
Risk Adjusted Equity Market	*8.75%*
DCF based	*10.0%*
Historic Utility	*10.5%*

Ms. McShane took an average of these 3 methodologies - which was 9.75%.

Ms. McShane then estimated the cost of equity using the DCF approach at 10.5% - 11%.

To each of her above approaches she added 50 basis points for flotation costs.

Finally, Ms. McShane opined that based upon her Comparable Earnings analysis, the Fair Return on Equity was 11.5 - 11.75%.

Table 11 of Ms. McShane's report provides a summary of the results of her 3 tests to estimate a fair return on equity for NP. For ease of reference, it is reproduced below:

Table 11

Test	Cost of Equity	Fair Return on Equity
Equity Risk Premium	9.75%	10.25%
Discounted Cash Flow	10.5-11.0%	11.0-11.5%
Comparable Earnings	N/A	11.5-11.75%

Ms. McShane then states at p. 70:

> *"In arriving at a reasonable return for a benchmark utility, I have given primary weight to the cost of attracting capital, as measured by both the equity risk premium and DCF tests. The "bare-bones" cost of attracting capital based on these two tests is approximately 9.75-10.75%. Including the allowance for financing flexibility, the indicated return on equity is 10.25-11.25%. However, the results of the comparable earnings test are also entitled to significant weight when setting a fair return. A fair ROE for NP based on all three tests is approximately 11.0%."*

On cross-examination, Ms. McShane admitted that in arriving at her fair ROE recommendation for NP of *"approximately 11 percent"* she gave approximately 25% weighting to the comparable earnings test and approximately 75% weight to ERP and DCF tests combined and that as between the ERP and DCF tests she gave these equal weight. {Ref - Oct 20 - p. 15-16]

At this juncture, the following are the more obvious observations that can be made about Ms. McShane's approach:

A. The Comparable Earnings Test - according to Ms. McShane this test has not been given weight by a Canadian regulator for years (Oct 20, p. 21-22); according to Dr. Booth is *"not an acceptable measure of estimating fair rates of return"* (Oct 22, p. 28); and according to Mr. Cicchetti has no place before the Board (Oct 22, p. 149).

B. Similar to what was observed by the Board in P.U. 19 (2003) at p. 48, Ms. McShane's DCF and comparable earnings tests produced results that were higher than the equity risk premium tests. Her DCF and comparable earnings tests actually produces estimates for the fair return on equity that exceed that sought by NP.

C. The DCF test - which effectively is used twice by Ms. McShane in her analysis, has not been afforded weight by Canadian regulators in years. [Oct 20, p. 23].

In her direct evidence, Ms. McShane [Oct 20, p. 4] stated, *"Every individual test has strengths, weaknesses, brings a different perspective to the estimation of the fair return and consequently giving weight to a battery of tests balances these considerations."* Obviously, Ms. McShane's professional judgment is that reliance on tests such as the comparable earnings test which are generally accepted to have no role in cost of capital proceedings is reasonable.

Ms. McShane's Update

On the first day of her testimony, Ms. McShane provided an Update to Evidence which was filed as Consent No. 2. The Update described how she had performed a DCF - based Equity Risk Premium Test - which had two versions, one of which was based on the relationship between DCF Costs of Equity and long-term government bond yields and another which estimated the cost of equity based on the relationship between DCF costs of equity, and the spreads between A-rated utility bond yields and long term government bond yields. The latter version as presented in Ms. McShane's report was premised on a higher spread than that prevailing at the time of the hearing (225 to 250 basis points spread versus an approximately 170 basis points spread).

Ms. McShane's Update to Evidence stated in part:

> *"Updating the latter version of the test for the change in spread reduces the cost of equity estimate to 10.1% including the .50% allowance for financing flexibility and my overall estimate of the fair return by approximately 5 basis points. The 5 basis point change does not change my recommended return for NP."*

From pages 76 to 87 [Oct 21 transcript] the Consumer Advocate addressed this Update to Evidence with Ms. McShane in cross-examination. Ms. McShane testified that when the new (lower) spread was utilized in her Schedule 12 equation [see Schedule 12 - DCF Based Equity Risk Premium Study for Benchmark US Electric and Gas Utilities Regression Analysis Results] the Equity Risk Premium at a Long Term Bond Yield of 4.25% was equal to 5.3% (as opposed to 6.1% as originally calculated based on the spread of 225-250 basis points). Interestingly, Ms. McShane acknowledged that if the credit spreads had increased from 225-250 bps to 350 bps by the time of the hearing, the ROE would have increased by only 6 basis points and the recommendation would still have been 11%. (See Undertaking

No. 3 of Oct 22, 2009)

Ms. McShane agreed that at the end of the day it was her ROE Recommendation that we are concerned with in this case [Oct 21, p. 85]. Therefore, it is indeed curious that Ms. McShane's ROE Recommendation is on the one hand so completely insensitive to utility spreads, while on the other hand her report (Ref p. 12, lines 299-301) refers to the material narrowing of the spread between the cost of new utility long term debt and the automatic adjustment formula ROE result as providing support for the conclusion that the AAFs are not producing reasonable results.

Similarly, it is curious that Ms. McShane argues (at p. 12) that the increase in the cost of equity and the widening of the equity risk premium *"is reflected in the significant increase in the volatility in the equity markets, as represented by the Implied Volatility Index ("MVX")" and that* "... a rising MVX is an indicator of rising investor risk aversion and a rising market risk premium" (p. 12, line 316-17) but it matters not a bit to her recommendations that the MVX was acknowledged by Ms. McShane to stand at "22" and indeed was down to about "18" at the end of September, 2009. (Ref Oct 21, p. 88-89) This is surprising indeed given that it is Ms. McShane's report which states at p. 13 *"... during much of 2002 - 2007, prior to the onset of the financial crisis, the MVX was relatively stable, trading within a range of 8 to 24."* We submit that it simply is inconsistent to argue as Ms. McShane does that a heightened MVX has signaled higher risk aversion and therefore an increase in the equity risk premium, but a lowered MVX (to levels seen between 2002 - 2007) does not indicate the opposite.

We shall return to Ms. McShane's evidence shortly, but first we wish to give an overview of Mr. Cicchetti.

Mr. Mark Cicchetti - Overview

Mr. Mark Cicchetti was called by Board Hearing Counsel to give evidence on cost of capital issues and the AAF. Ultimately, Mr. Cicchetti's evidence is of relatively little use as an estimate of the fair return for NP. His limited experience with AAF mechanisms (let alone their operation in Canada) makes Mr. Cicchetti a rather poor source of guidance on the AAF of NP.

As regards his ROE recommendation of 9.60%, Mr. Cicchetti's report is a classic illustration of the proposition that just because one is recommending something near the middle does not mean that one is correct, reasonable or, in his case, even worthy of weight.

Mr. Cicchetti's approach of looking only to US firms' data to ground his analysis (which itself is entirely DCF-based) leads to an ROE recommendation that is simply too high for NP.

This was Mr. Cicchetti's first assessment of the cost of capital of a Canadian Utility. He had never testified in Canada before a regulatory board. His testimony on cost of capital issues over the past 15 years has been restricted (save for a single case before the Michigan P.S.C.) to testimony provided to the Florida Public Service Commission on a relatively few occasions. [CA PUB 20] Mr. Cicchetti's experience with AAF mechanisms has been limited. [Oct 22, 2009, p. 149 - 150]

The Use of U.S. Utility Holding Company Data

Mr. Cicchetti's and Ms. McShane's analyses of the fair return on equity for NP rely heavily upon U.S. Utility Holding Company data.

In fact, Mr. Cicchetti confirmed that all of his estimates of the fair ROE came from analyzing either a sample of US electric or natural gas utilities using a two-stage DCF estimate or a DCF- based risk premium model. [CA PUB 4 (a)]

In Ms. McShane's case, her DCF analysis draws exclusively on U.S. company data. [Oct 20, p. 27] In addition, her second approach to the Risk Premium Test, namely the DCF-based Equity Risk Premium Test draws exclusively on U.S. company data. [Oct 20, p. 28]

Ms. McShane's third approach to the Risk Premium Test, namely the Historic Utility Equity Risk Premium approach utilizes historic US electric and gas utility returns along with historic Canadian utilities returns, albeit over different periods of time.

Both Mr. Cicchetti and Ms. McShane believe that the Board may rely on this US data and the ROE estimates that emanate from it without making any adjustments whatsoever. The following exchange (Oct 22, 2009, p. 19, lines 9 to 19) underscores Mr. Cicchetti's view:

> *"Mr. Johnson:*
> *Q. Now you recommend that the Board not apply any adjustments to the numbers that flow out of your DCF tests, right?*
>
> *Mr. Cicchetti:*
> *A: Correct*
>
> *Mr. Johnson:*

Q: Take them at face value and say, Board, that's fair for Newfoundland Power. Have I got you correct (sic)?

Mr. Cicchetti:
A: Yes."

Ms. McShane testified that she has not made any adjustments adding *"I have not considered that any adjustments are necessary."* [Oct 20, p. 37-38]

Mr. Cicchetti stated on direct (Oct 22, p. 118, lines 7 to 16) that he tried to get as accurate a representation of Newfoundland Power as he could. He stated,

> *"If you want a publically traded stock that's small, T& D related, doesn't have any non-regulated activities, there's none out there. I went through great pains to try and get stocks that I considered similar to the company in order to use in my analysis and in looking at them, there just weren't Canadian companies that were as accurate a sample as I believe the highly rated low-risk utilities that I used. . ."*

Mr. Cicchetti's report at p. 19 cites as *"Additional reasons"* supporting the use of US regulated utilities as proxies for NP the following:

(i) Canadian and US utilities generally have similar operating and regulatory environments;
(ii) there is significant integration between US and Canadian capital markets; and
(iii) rating agencies have considered utilities with similar characteristics but domiciled in different countries to be peers.

Mr. Cicchetti then set out to select the US utilities which he deemed to be comparable to NP. For his DCF analysis, he stated that he required companies with long-term analyst forecasts for growth, earnings, return on equity and dividends. To be included in his group of US utilities - the utilities had to be small or mid-cap companies, have a Value Line Safety Rank of 1 or 2, a bond rating of Baa1 or better and not be currently involved in a merger.

When asked why he excluded larger cap companies for the sample group, Mr. Cicchetti stated:

> *"The point is to get a comparison group that is similar to Newfoundland Power and Newfoundland Power, in my opinion, in terms of size, is small to mid cap size. They're a regulated utility, electric utility. We look at their equity ratio, their safety rank, and just the importance of it is to try and get a group of comparable companies similar to the company that you are looking at."* [Oct 22, p. 178]

As noted, the companies also had to have a Value Line Safety Rank of 1 or 2. Mr. Cicchetti considered that Newfoundland Power would be considered as a Safety Rank 1 - being the safest [Oct 22, p. 171]. He confirmed that a Safety Rank of 1 would apply <u>to stocks</u> that were the safest, most stable and least risky investments relative to the Value Line Universe. (P. 173) Safety Rank 2 would be stocks of above average safety and would be safer and less risky than most. For a Safety Rank of 3, the stocks are of average risk and safety.

Mr. Cicchetti, during cross-examination by the Consumer Advocate, was brought through a review of several of his selected companies and regardless of what differences were pointed out to him as between the selected company and NP, Mr. Cicchetti fell back on the position that these companies had similar bond ratings. For instance when it was pointed out to Mr. Cicchetti that MGE was at risk for fuel purchase costs the following was representative of his view:

> *"Q: . . . Does NP have a similar risk?*
>
> *A: No, but again there's going to be individual differences between these*

companies, and you have to look at the entire picture, looking at bond ratings, and the other things we've talked about, these group of companies are similar risk to NP."

In fact, Mr. Cicchetti seemed to be bothered by the fact that he was being questioned whether these companies were similar in risk to NP. The importance of the bond rating became the key for Mr. Cicchetti as can be seen in the following passage from Oct 22 at p. 199:

> *"A. Obviously, reasonable risk, investors are risk adverse, and would choose for a given return, less risk, rather than more risk, but you keep looking at specifics associated with business risk, and in order to evaluate a company as comparable, you have to include business risk and financial risk, and with regard to regulatory risk, you have to look at the allowed returns, the capital structure, the financial metrics that fall out there, <u>and all of that gets wrapped up to a great extent in the bond rating, and so on that basis these are comparable</u>. I mean, you can beat this to death, but it's not going to change the fact that you have to look at the overall investment risk characteristics and, yes, there are specific business risk items associated with Newfoundland Power that are less risky than a lot of these companies, but all in all, they're similar".* (emphasis added)

The Consumer Advocate finds it interesting that once Mr. Cicchetti took the stand that the *"bond rating"* took on such critical importance to the integrity of his sample. Of course, by the time he had taken the stand he was fully aware that detailed binders of information on each of the companies in his and Ms. McShane's US samples had been circulated by the Consumer Advocate for cross-examination purposes. Prior to this, the bond rating was just one of several factors. For instance, in CA-PUB-11, the Consumer Advocate asked as follows:

> *"Q. Re: Newfoundland Power's company overview pages 13-15*
>
> *b. Can Mr. Cicchetti explain in detail how he came to the conclusion that Newfoundland power is equivalent in risk to his US proxies, that*

is, what explicit checks did he conduct to validate his choice of proxies.

A. (b.) *Mr. Cicchetti determined Newfoundland Power was similar in risk to the comparison utilities by examining the nature of their operations, their business risk, financial risk, bond rating, beta, equity ratio, Value Line Safety Rating, size, earnings, and regulatory support."* (emphasis added)
[p. 126, Oct 21/09]

In addition, Mr. Cicchetti had confirmed, prior to the hearing, in response to CA-PUB-15 that rating agencies simply predict the probability and consequences of default and they do not estimate fair rates of return or capital market conditions or even comment on nominal debt costs.

During the hearing, Chairman Wells addressed Ms. McShane as to what a similar bond rating amongst firms says to a bond investor and an equity investor respectively [October 21, pp. 125-129]. To a bond investor, similar ratings says that there is a relatively similar probability that the utility will not default. While the bond rating reflects a composite of the bond rater's view as to the combination of business and financial risks, Ms. McShane stated:

"To some extent, the bond rater's views will be different from the equity investor's view, since the equity investor is the residual recipient of the cash flows. So the bond rating is not a determinative measure of the relative risk to an equity investor. It's one indicator. There may be differences between how the debt rating agencies look at the risk and how the actual bond investors view the risk. . . " (emphasis added)

Chairman Wells then turned to this question:

"Q. Okay. Now just take me from that then, what does it say? What does the rating from these two companies say to an equity investor? You said it's an indicator, but there are others.

A. *It would be one of -*

Q. *Just flesh that out for me now.*

A. *Okay. So the bond rating would be one indication. Other indications would be if you looked at the Betas of the firm, so are they relatively similar from an equity - - that would be one thing that an equity investor would look at. They would look at the price to earnings ratios of the company. Are investors willing to pay more for a given stream of earnings? So if you had two companies with utilities with very different price earnings ratios within the same industry, the company with the lower price earnings ratio or a lower market to book ratio might be viewed as riskier than a company with a higher PE ratio or a higher market to book ratio.*

Chairman:
Q. *And none of those factors will be taken into account by the bond rater?*

Ms. McShane:
A. *The equity -*

Chairman:
Q. *In the initial exercise to determine the -*

Ms. McShane:
A. *No, they would not be focused on these equity market indicators. They would be focused simply on those cash flows or the outlook for the cash flow.*

Chairman:
Q. *After the bonds are -*

Ms. McShane:
A. *Exactly."*

Moody's puts the following disclaimer on its Rating Opinions in bold and capitalized print:

"CREDIT RATINGS ARE MOODY'S INVESTORS SERVICE, INC.'S (MIS) CURRENT OPINIONS OF THE RELATIVE FUTURE CREDIT RISK OF ENTITIES, CREDIT COMMITMENTS, OR DEBT OR DEBT-LIKE SECURITIES. MIS DEFINES CREDIT RISK AS THE RISK THAT AN ENTITY MAY NOT MEET ITS CONTRACTUAL, FINANCIAL OBLIGATIONS AS THEY COME DUE AND ANY ESTIMATED FINANCIAL LOSS IN THE EVENT OF DEFAULT. CREDIT RATINGS DO NOT ADDRESS ANY OTHER RISK, INCLUDING BUT NOT LIMITED TO: LIQUIDITY RISK, MARKET VALUE RISK, OR PRICE VOLATILITY. CREDIT RATINGS ARE NOT STATEMENTS OF CURRENT OR HISTORICAL FACT. CREDIT RATINGS DO NOT CONSTITUTE INVESTMENT OR FINANCIAL ADVICE AND CREDIT RATINGS ARE NOT RECOMMENDATIONS TO PURCHASE, SELL, OR HOLD PARTICULAR SECURITIES. CREDIT RATINGS DO NOT COMMENT ON THE SUITABILITY OF AN INVESTMENT FOR ANY PARTICULAR INVESTOR. MIS ISSUES ITS CREDIT RATINGS WITH THE EXPECTATION AND UNDERSTANDING THAT EACH INVESTOR WILL MAKE ITS OWN STUDY AND EVALUATION OF EACH SECURITY THAT IS UNDER CONSIDERATION FOR PURCHASE, HOLDING, OR SALE." [Reference: Exhibit 4 - Credit Opinion of 6 March 2009]

Dr. Booth also pointed out that equity investors do not generally look to bond rating reports. Dr. Booth testified (Oct 21, 1009, p. 180, lines 10 to 25):

"Dr. Booth:

A. First of all when I look at equity reports, it is very, very rare to see an equity analyst analyze a company and then refer to the bond yield - - sorry, refer to the bond rating. In fact, I was looking at Bank of Montreal's analysis of Fortis this summer and they've got a buy recommendation of Fortis and I didn't see anywhere where they referenced the bond rating. Generally the equity markets do not look seriously at bond ratings. The estimated equity rates return may be affected by some of the factors in bond ratings and the bond yield, but the equity markets march to different drummers. They're different institutional purchases, they look at different facts."

In this case, the question for the Board's determination is what is a fair ROE for NP. This involves a careful examination of NP's risks, including risks that are important to equity investors. As part of that determination, Mr. Cicchetti made a number of remarkable observations:

- the regulatory support in NL is "phenomenal;" [Oct 22; p. 145] while OG&E (one of his sample firms) has "good regulation", NP has "exceptional regulation." [Oct 22, p. 227-8]

- given NP's isolated geographic location and customer mix, he had not seen a single utility in his samples as well protected from competition as was NP [Oct 22, p. 162]

- given NP's stable customer base, he had not seen a single utility where the rate base was so stable and the need to raise capital was expected to be so relatively modest going into the future. {Oct 22, p. 163]

Mr. Cicchetti also acknowledged that the following factors would be considered important by equity investors:

- whether the utility had fuel price protection [p. 151]

- whether the utility is able to earn its allowed return [p. 152]

- the relative supportiveness of the regulatory environment [p. 152]

- whether the utility had the ability to make applications to the regulator to establish deferral accounts outside of General Rate Applications [p. 152]

- whether energy supply cost variances could be covered off in a deferral account [p.

153]

- whether the utility had pension expense variances covered off by way of a deferral account [p. 153]

Mr. Cicchetti's report (at p. 17) says that "*determining a valid proxy for investor expectations regarding the expected cash flows of a stock (the expected dividends) is the most important, and often most contentious issue in determining the cost of equity using the DCF formula.*" Mr. Cicchetti also acknowledged the rather obvious point that there is a risk, depending upon the choice of the proxy group, of <u>over-estimating the fair return on equity</u>. Mr. Cicchetti was asked what the implications were of including in the proxy sample a holding company that has higher risk non-regulated operations or businesses when the goal is to establish the fair rate of return for a wholly regulated company like Newfoundland Power. The following exchange occurs at pp. 154-155:

"Mr. Cicchetti:
A. Again, you would have to look at the entire business risk and financial risk and total risk. <u>The answer to your questions is would the non-regulated operations tend to increase the required return? Yes, they would</u>.

Mr. Johnson:
Q. Yeah.

Mr. Cicchetti:
A. Would it be a meaningful amount? That's disputable.

Mr. Johnson:
Q. Well, what judgment should be - - what's the cutoff percentage of non-regulated income in order to make you comfortable that the proxy group is not overstating what the fair return would be?

Mr. Cicchetti:

A. *It would depend. It would depend on the utility, but if you were <u>to exclude all publicly traded utility companies that had non-regulated operations, I don't know that you would be left with any to compare to</u>."* (emphasis added)

As can be observed in the transcript from page 156 to 158, Mr. Cicchetti was non-committal as to what level of non regulated earnings and activities a utility holding company would need to have in order for him to exclude it from his sample. Mr. Cicchetti stated that in the companies he chose, he <u>did not</u> consider any of these companies' non-regulated activities as increasing the required return by a meaningful amount (p. 157) but allowed that:

"If the Board was concerned about that to a significant extent, I say the required return is calculated within a range. They could take that into consideration when they're making that determination".

Of course, Mr. Cicchetti was also on the record as stating that no adjustments were necessary. The inflexibility of this witness and the inability of the witness to allow the facts to constrain his judgment as to the fair return for NP was writ large when he was directed to the corporate materials on OGE Energy which was listed as a comparable electric company in his report. OGE Energy, according to MAC-8 had a Safety Rank of 2, a beta of .75, an equity ratio of 50%, a BBB+ S&P Bond Rating and a market capitalization of 2.6 billion (US). The discussion of OGE takes place from p. 221 to 228 of the October 22 transcript. The record will reflect that Enogex is a non-regulated part of OGE Energy Corp. Enogex operates a pipeline system engaged in natural gas gathering, processing, transportation and storage. Its system includes about 8,200 miles of pipes, seven natural gas processing plants and 24 billion cubic feet of natural gas storage capacity.

At p. 10 of the OGE 2008 Annual Report (at Tab 4 of the OGE binder), the Financial Performance of both the regulated and non-regulated businesses are shown. Net income for the regulated operation was $143,000,000 in 2008; the non regulated business had net income of $91,000,000, a very significant contributor to the bottom line of OGE. In 2008, the regulated operation earned 9.3% return on equity but the non-regulated earned 24.8%. When it was put to Mr. Cicchetti that investors in OGE Energy Comp. were getting quite a lift from the non-regulated side of the business the following exchange took place: (p. 226-227)

"Mr. Cicchetti:
A. Yes, and those operations are transportation and storage of natural gas. It's not that much difference, in the past, recent past, how it was regulated.

Mr. Johnson:
Q. But what does that - - how should that make me feel better?

Mr. Cicchetti
A. You'd have to look at the entire operations of the company, how much riskier is this non-regulated line of business? It's not materially that much riskier, it's part of the natural gas energy business.

Mr. Johnson:
Q. But wouldn't it affect the equity investors' expectation as to what the return is going to be from OGE Energy Corp versus what the return should be to a shareholder of Newfoundland Power?

Mr. Cicchetti:
A. I'm sure it comes into consideration, yes.

Mr. Johnson:
Q. How?

Mr. Cicchetti:
A. Well they're re-evaluating the entire company. I'm sure that 24.9 percent has gotten someone's attention.

Mr. Johnson:
Q. It would get your attention, wouldn't it?

Mr. Cicchetti:

A. *Certainly."* (emphasis added)

OGE is but one example of the questionable proposition it is to rely on these US samples with their expected shareholder returns, bearing in mind that Mr. Cicchetti and Ms. McShane both are of the belief that *"no adjustment"* is required in order for it to be applicable to NP. In our submission, reliance on these proxies does a serious injustice to NP's ratepayers and seriously distorts the reasonable expectations of an investor in NP.

Another illustration is South Jersey Industries. South Jersey Industries is found in Mr. Cicchetti's comparable gas companies sample. South Jersey Industries, according to MAC-9 had a Safety Rank of 2, a beta of .65, an equity ratio of 62.00% and a BBB+ S&P Bond Rating. It is unclear how this company can be said to have a 62% equity ratio when at p. 2 of the Letter to Shareholders at Tab 3 it states, *"Equity to capitalization ratio improved 7.9 percentage points to 47.4% at year end 2008 from 39.5% in 2004."* In any event, the discussion of South Jersey Industries goes from p. 181 to 185 of the transcript. The record will reflect that South Jersey Industries has as one of its goals *"To execute from a low to moderate risk platform."* (emphasis added) (See p. 4 of 2008 Annual Report) This too is a company that receives a considerable proportion of its earnings from its robust non-utility activities. At page 2 of its 2008 Annual Report, the company states:

> *"Our success comes from the robust growth and profitability of our non-utility activities, along with reliable, steady growth of our utility. To illustrate this point, our non-utility businesses contributed 27% to SJI's earnings in 2004, compared with a 42% contribution to economic earnings in 2008. This change occurred despite utility net income increasing from 31.5 million to 39.4 million during this time."* (emphasis added)

As the Board heard during the cross-examination of both Ms. McShane and Mr. Cicchetti, the samples of these two experts were filled with companies which had significantly less regulatory support and regulatory protections than NP enjoys. No attempt will be made here to re-cap the significant differences that exist between each of these US utility holding companies and NP. For ease of reference, however, the following references are made to the transcript:

<u>Companies Selected solely by Mr. Cicchetti</u>	Transcript (p.)
South Jersey Industries	p. 141 - 143; 181 - 185 (Oct 22, 2009)
CH Energy Groups	p. 185 - 189 (Oct 22, 2009)
MGE Energy	p. 190 - 207 (Oct 22, 2009)
Wisconsin Energy Corporation	p. 207 - 216 (Oct 22, 2009)
Allete	p. 216 - 221 (Oct 22, 2009)
OGE Energy	p. 221 - 228 (Oct 22, 2009)
Alliant	p. 228 - 230 (Oct 22, 2009)

<u>Companies Selected solely by Ms. McShane</u>	Transcript (p.)
Southern Company	p. 124 - 135 (Oct 20, 2009)
FPL	p. 2 - 13 (Oct 21, 2009)
Duke Energy	p. 13 - 27 (Oct 21, 2009)
Dominion Resources	p. 27 - 36 (Oct 21, 2009)
Consolidated Edison	p. 36 - 47 (Oct 21, 2009)

<u>Companies Selected commonly by Ms. McShane & Mr. Cicchetti</u>	Transcript (p.)
WGL Holdings Inc.	p. 106 - 114 (Oct 20, 2009)
Vectren Corp.	p. 114 - 124 (Oct 20, 2009)
Scana	p. 135 - 151 (Oct 20, 2009)
Piedmont Natural Gas	p. 151 - 161 (Oct 20, 2009)
NSTAR	p. 161 - 171 (Oct 20, 2009)
Northwest Nat. Gas	p. 171 - 178 (Oct 20, 2009)
New Jersey Resources	p. 178 - 186 (Oct 20, 2009)
AGL Resources	p. 47 - 53 (Oct 21, 2009)

The use of the sample companies of Mr. Cicchetti simply leads to an over-statement of the fair return for NP. Mr. Cicchetti was asked on the stand whether he had used in the previous 3 years the "*same or substantially the same sample*" as he had used in this case and to report back as to the specific utility cases in which he had used the same or substantially the same sample. Mr. Cicchetti stated (p. 167, line 13) that he would have used a list much like his gas companies sample in the last 2 or 3 years in testifying. Unfortunately, his initial memory was not confirmed and he reported in U-4 that in fact "*over the past three years, Mr. Cicchetti has not used a sample of electric or natural gas companies that he considers to be the same or substantially the same as the sample used as comparables for NP. He has used some of the companies that were included among the NP comparables before, but for each hearing he has conducted a separate examination of compare to find the best comparables.*"

A further undertaking was requested of Mr. Cicchetti regarding his use of Value Line Safety Rankings. His comparable electric utilities had 6 companies with a Safety Ranking of 2 and 3 companies with a Safety Ranking of 1 - the latter being N Star, MGE Energy Inc. and CH Energy Group. His comparable gas companies had 3 companies with a Safety Rank of 2 - and 3 companies with a Safety Rank of 1 - these being New Jersey Resources, Northwest Natural Gas and WGL Holdings. Though Value Line does not specifically report on NP, Mr. Cicchetti was asked what safety rating would apply to NP and he stated "*one*". (p. 171, line 20) Mr. Cicchetti was asked to provide a re-calculation of schedules MAC 10 and 11 using only companies that he had identified having a Safety Rank of 1. Mr. Cicchetti reported in Undertaking 5 that the cost of common equity for his electrics with a Safety 1 rank would be 8.98% (instead of 9.57% as in MAC 10) and the cost of common equity for his gas companies with a Safety Rank of 1 would be 8.79% (instead of 9.53% as in MAC 11). Mr. Cicchetti testified (Oct 22, 2009, p. 233-4) that he did not anticipate that reducing the size of his samples to Value Line 1 companies would pose any problem as to the usefulness of the information obtained.

The evidence has disclosed that these Safety 1 companies themselves have significant risk features that NP does not possess. To illustrate, on the electric side:

<u>CH Energy Group</u>

- p. 26 of the 10-K at Tab 4 of the binder states:

> "As the graphs above indicate, CH Energy Group is comprised of 85% electric and natural gas assets which are subject to regulation by the PSC (as discussed in more detail below) and 15% non-regulated assets. The corresponding net income profile is 75% regulated electric and natural gas <u>and 25% non-regulated businesses</u>." (emphasis added)

- p. 65 of 367 of Tab 4 - outlines a recent denial of a company petition to defer $990,000 in gas expenses with the PSC "noting that while Central Hudson satisfied the standards for demonstrating the expense items were incremental and Central Hudson had not earned its allowed rate of return, PSC did not view the expense items as material and extraordinary in nature."

- Tab 3 of binder - shows that Moody's on September 9, 2009 downgraded Central Hudson Gas & Electric senior unsecured debt from A2 to A3 and kept the outlook negative. "Increased dependence on rate filings to address regulatory lag in the currently challenging economic environment adds to credit uncertainty", according to Moody's. "The negative outlook takes into account the utility's weak credit metrics and ongoing need for rate relief to support large planed capital expenditures and strengthen financial performance even as the PSC imposes austerity measures on all New York utilities, Moody's noted."

<u>MGE Energy Inc.</u>

- As noted at p. 7-8 of the 10-K, electric revenues are only about 34% for residential sales with about 54% (in '08) as commercial.

- The top of page of the 10-K filing shows that MGE purchases 39% of its power and generates the balance.

- p. 56 of 10-K explains that MGE has Regulatory Recovery Risk (see p. 196 of transcript). MGE assumes the risks and benefits of fuel cost variances within a 2% deadband.

- p. 18 of the 10-K shows that the utility is at risk for weather -affected customer demand. (and see p. 203 of transcript of Oct 22, 2009)

On the gas companies side, WGL Holdings had a Safety Ranking of 1, a .65 beta, 62.00% equity ratio and AA- credit rating according to Mr. Cicchetti's MAC-9 schedule.

- WGL is at risk for the revenue effect of customer usages in 20% of their service territory. (Transcript - Oct 20, p. 108)

- WGL is exposed to Weather Risk. (Transcript - p. 108 - 109)

- WGL was recently disallowed $4.6 million in gas purchase costs in Maryland. (Transcript p. 110 - 111)

Northwest Natural Gas

Northwest Natural Gas, according to MAC-9 had a Safety Rank of 1, a beta of .60, an Equity Ratio of 53% and an S&P Bond Rating of AA-.

- Shareholders in the company share the risk of gas cost variances through a gas cost sharing mechanism. Regulators recently revised the mechanism to "better balance the risks and rewards between customers and shareholders." (see p. 175 - 176 of October 20, 2009 transcript)

New Jersey Resources

- In fiscal year 2008 approximately one-half of the company's net financial earnings came from NJRES, its unregulated wholesale energy services company. (see p. 182 of October 20, 2009)

- The regulated utility is subject to a Conservation Incentive Program approved by the regulation in 2006 - which aligns the interest of customers and shareholders by incenting the utility to help customers lower their energy bills.

In sum, Mr. Cicchetti's evidence is of little practical use to the Board. His evidence does however clearly confirm why US ROEs cannot be applied to NP without making very serious adjustments. In short, he has materially over-stated the fair return for NP.

Ms. Kathleen McShane - Re-visited

The more obvious observations that can be made about Ms. McShane's evidence have been made previously. The following comments must also be made as regards the following:

(a) Ms. McShane's US Comparables

(b) The Risk Adjusted Market Risk Premium

(c) The Use of Adjusted Betas

Ms. McShane's US Companies

Ms. McShane selected 13 US Electric and Gas companies for her Benchmark Sample of US Electric and Gas utilities. As noted, several of her US companies overlap with Mr. Cicchetti's samples. She also has several companies which Mr. Chicchetti did not rely upon.

Ms. McShane stated that 5 of the 13 companies (Dominion Resources, Duke Energy, FPL, Scana and Southern Company) would be considered an integrated electric utility meaning that they are engaged in generation, transmission and distribution services. [Transcript Oct 20, 2009, p. 44 - 45] NP, of course, is predominantly a T&D utility. According to Undertaking No. 2, Moody's does not include integrated utilities, much less US integrated utilities in NP's peer group.

Ms. McShane's report (see p. 34, line 869) refers to the fact that Moody's publishes "*quantitative guidelines*" for utility ratings (ie the March 2005 Rating Methodology: Global Regulated Electric Utilities), but her report does not refer to the fact that Moody's also provides commentary on qualitative factors as well in the same Rating Metholodogy document.

In cross-examination it was pointed out to Ms. McShane that in the 2005 Moody's Methodology, Moody's indicates that it considers US integrated utilities as being in a medium-business-risk operating environment. (Transcript Oct. 20, 2009, p. 41 - 44) The passage that was put to Ms. McShane was from p. 8 of the document and stated as follows:

> *"Financial ratios are more useful for companies operating in a low risk business environment where there is a high degree of regulated activities and a supportive regulatory system. This might include the US, US transmission and distribution utilities (T&Ds), Canada or many European countries. <u>Medium-business-risk operating environments would include US integrated utilities</u>."* (emphasis added)

Ms. McShane was only prepared to go so far as to allow that Moody's was saying that "*generally speaking*" - a US integrated utility would be a medium-business-risk operating environment. (Transcript of Oct 20, 2009, p. 44)

Ms. McShane was referred to her evidence from NP's 2003 GRA which was entered as Consent No. 3 [see p. 49 - 51 of Oct 20, 2009 Transcript]. In that case, Ms. McShane relied on LDCs rather than electric utilities. The following exchange took place:

> *"Mr. Johnson:*
> *Q. Just read for the record what you said about proxy utilities in that case.*
>
> *Ms. McShane:*
> *A. 'That I relied on LDCs rather than electric utilities for three reasons. Newfoundland Power's primary electric distribution utility. There are a very limited number of US electric utilities whose operations are primary*

distribution and/or transmission. Second, the operations of electric and gas distribution have significant parallels and are frequently considered to be proxies for one another. Third, it is noted in Section 2 of Business Profile Score 3, which is likely to be assigned to Newfoundland Power is the same as that of a typical US LDC. In contrast, the typical business score of the US electric utilities is 4'. (emphasis added)

Mr. Johnson:

Q. Yeah, so you were acknowledging that the LDC would be of a more - more in keeping with the risk profile of Newfoundland Power, but not US electric utilities generally, right?

Ms. McShane:

A. Yeah, I think that's fair, and, of course, I don't have all US vertically integrated utilities in here. It's those that met the criteria of being low risk."

The fact is that NP is a predominantly transmission and distribution utility with very minor generating capacity. Moody's, which rates NP's debt, considers that US integrated utilities are in a medium-business-risk operating environment. In Undertaking No. 2, Moody's provided a listing of companies (6 in all) that it considered to be relatively good peers for NP. The Undertaking states:

"The group is comprised of companies that are predominantly or exclusively T&D utilities within the Baa 1 rating category. While NPI obviously has generation component, the vast majority of the energy delivered by NPI is procured from NLH rendering NPI closer to a pure T&D utility rather than to a vertically integrated utility. One of the companies listed above, Orange and Rockland Utilities, is both an electric T&D utility and gas LDC. However, I include O&R because Moody's views the business risk profile of gas LDCs to be similar to, indeed generally somewhat lower, than that of electric T&Ds.

The peer group is also comprised of relatively small utilities. While Connecticut Light and Power and PPL Electric Utilities are arguably mid-sized companies with assets of US$8.4B and US$ 5.2B respectively, they are significantly smaller than two other Baa 1-rated utilities, Oncor Electric Delivery ($14B assets) and Public Service Electric and Gas ($16B assets), which I have not included as peers due to the significant size differential.

While companies in a peer group will always have unique attributes than can complicate comparisons, I believe that the group above includes most of NPI's closet peers within the universe of companies rated by Moody's." (emphasis added)

Ms. McShane did not refer to Moody's 2005 Methodology Document as regards its comments on the business risk operating environment of US Integrated Utilities. Ms. McShane also did not refer to Moody's rather comprehensive commentary on Regulatory Supportiveness, a key qualitative factor considered by Moody's. The Regulatory framework in which a utility operates is of paramount importance as an aspect of risk to which investors are exposed. Ms. McShane made this point quite explicitly in her 2007 evidence for NP's 2008 GRA. The 2007 evidence was entered as Consent No. 4. Ms. McShane was referred to her 2007 evidence during cross-examination. (see Transcript Oct 20, 2009, p. 51 - 53). At the time, she referred to the regulatory framework as being viewed as the *"most significant aspect of risk to which investors in the utility are exposed."* At page 52 of the October 20, 2009 transcript, Ms. McShane read from her 2007 evidence:

*"A. 'The regulatory framework in which a utility operates is frequently viewed as the most significant aspect of risk to which investors in the utility are exposed. The financial community is very conscious of the regulatory environment. It's highlighted in reports of **both** bond rating agencies and **investment analysis**. Regulation has the power to expose utilities to enormous risk by permitting bypass facilities, disallowing costs, approving rate designs that are tilted against recovery of fixed costs, or returns that do not conform with informed investors perspective of risk. Alternatively, regulation can provide an environment characterized by consistency and by even handedness conductive to continued growth consistent with economic allocation of resources. Affording the utility a reasonable opportunity to achieve a fair return. Enlightened regulation will mitigate risks that are substantially beyond management control and award a return that provides both; **one, fair compensation for the risks that are left with management**; two, incentives to achieve and exceed the allowed return through continued improvement and productivity'.* (bold and underlining added)

Mr. Johnson:
Q. Now, Ms. McShane, do you agree that these statements that you made before this Board in 2007 are as true today as they were when you made them?

Ms. McShane:
A. Yes."

Moody's 2005 Methodology Document makes it clear that it considers Canada to be in the highest category (out of 4) of regulatory supportiveness - SRE 1, a distinction shared with only Australia, Iceland, Finland, Hong Kong, Japan and the UK. The SRE 1 ranking indicates that the Regulatory framework is fully developed and has shown a long track record of being highly predictable and stable and there is a very high expectation of timely recovery of costs and investments. In Moody's 6 March 2009 credit opinion (Exhibit 4), Moody's stated,

"Moody's considers the PUB to be one of the more supportive regulations in Canada..."

The Moody's 2005 Methodology document indicates that about one-half of the US states would fall into SRE 2 with the remaining one-half of US states falling into the SRE 3 category.

SRE 2 is defined as follows:

Regulatory framework is fully developed, is predictable and stable and there is a high expectation of timely recovery of costs and investments.

SRE 3 is defined as follows:

Regulatory framework is well developed but there is a lower assurance of timely recovery of costs and investments; there may also be evidence of some inconsistency or unpredictability in the way that the regulatory framework has been applied.

Countries such as Austria, France, Germany, New Zealand, Portugal, Netherlands, Norway, Singapore, Spain an Sweden would be considered SRE 2. Joining about one-half of the US states in SRE 3 would be Chile, Czech Republic, Estonia, Greece, Israel, Korea, Latvia, Malaysia, Taiwan and Thailand.

Dominion Resources which was one of the vertically integrated electric utilities in Ms. McShane's sample carries on business in West Virginia (SRE 3), Ohio (SRE 3), and Pennsylvania (SRE 3). [see Transcript Oct 20, 2009, p. 58 - 61] Pennsylvania was the state in the Duquesne case where the regulator refused to permit a utility that had constructed a nuclear power facility to recover the cost of same from ratepayers on the grounds of imprudency. [p. 61 - 62]

In CA-NP-18(a) NP was asked to *"provide all statistical work that Ms. McShane has performed to justify the assumption that US utilities are comparable in risk to NP."* Ms. McShane stated in reply that her reliance on a sample of US utilities was not based on statistical analysis, rather it was *"based on knowledge of both the regulatory and operating environments of both Canadian and US utilities, an understanding of the capital markets in both countries, supplemented by the five 'specific considerations'"* one of which was her having taken a *"review of the regulatory climate in each state, including the various regulatory mechanisms"* which she provided in Attachment "A" to the reply.

Ms. McShane's review of the regulatory climate as summarized in the Attachment "A" to CA-NP-18 does not refer to the regulatory support rankings of Moody's in its 2005 Methodology, even though the 2005 document specifically applies to US electric utilities. According to Moody's 2005 Methodology, not a single one of the electric utilities in Ms. McShane's sample would enjoy the regulatory support present in Newfoundland and

Labrador, or for that matter in Canada. Ms. McShane in her Regulatory Climate overview provided in CA-NP-18 relied upon the ratings of Regulatory Research Associates (RRA) (p. 66, Oct 20, 2009). According to Ms. McShane, the highest ranking in the RRA system is "Above Average 1". Not a single one of the utilities in her sample achieved that ranking either. "Average 3" was the lowest ranking given by RRA, with "Above Average 3" being just above it. AGL Resources, Consolidated Edison, Dominion Resources and WGL Holdings each had regulated utilities operating in states with either an "Average 3" or "Above Average 3" ranking. Out of the 33 separate Regulatory Climate rankings provided by Ms. McShane based on the RRA rankings, only 9 were in the "Average 1" or "Below Average 1" categories, 17 were in the "Average 2" or "Above Average 2" categories and 7 were in the "Average 3" or "Above Average 3" categories. There is no evidence that RRA publishes Regulatory Climate rankings for NP or for that matter any other Canadian utility.

Ms. McShane stated that she used Moody's data for her Moody's Regulatory Support Rating (for Gas only), based on a gas methodology issued by Moody's in 2006. (Oct 20, 2009, p. 71) The record will reflect that Moody's replaced its 2006 gas methodology (and the 2005 methodology previously referred to) with the August 2009 "Regulated Electric and Gas Utilities" document. At p. 6 of the 2009 Moody's document it states at pp. 6 - 7:

> *"<u>Moody's views the regulatory risk of U.S. utilities as being higher in most cases than that of utilities located in some other developed countries, including Japan, Australia, and Canada</u>. The difference in risk reflects our view that individual state regulation is less predictable than national regulation; a highly fragmented market in the U.S. results in stronger competition in wholesale power markets; U.S. fuel and power markets are more volatile; there is a low likelihood of extraordinary political action to support a failing company in the U.S.; holding company structures limit regulatory oversight; and overlapping or unclear regulatory jurisdictions characterize the U.S. market. <u>As a result, no U.S. utilities except for transmission companies subject to federal regulation, score higher than a single A in this factor</u>.*
>
> *The scores for this factor replace the classifications we had been using to assess a*

utility's regulatory framework, namely, the Supportiveness of Regulatory Environment (SRE) framework, outlined in our previous rating methodology (global Regulated Electric Utilities, March 2005), which we are phasing out. Generally speaking, an SRE 1 score from our previous methodology would roughly equate to Aaa or Aa ratings in this methodology; an SRE 2 score to A or high Baa; an SRE 3 score to low Baa or Ba, and an SRE 4 score to a B. For U.S. and Canadian LDCs, this factor corresponds to the "Regulatory Support" and "Ring-fencing" factors in our previous methodology (North American Regulated Gas Distribution, October 2006)." (emphasis added)

The Consumer Advocate was struck by the fact that without exception each of the companies that populated Ms. McShane's sample appeared to have higher risk features in factors that would be important to investors than NP has. None were a T&D company. Several had large generation responsibilities (eg. Southern Company - 42,000 megawatts - Oct 20, 2009, p. 126; Dominion Resources - 27,000 megawatts - Oct 21, 2009, p. 27). Several more had large non-regulated components. For example, FPL's non-regulated generation business provided about 45% of earnings in 2008 according to Ms. McShane (Oct 21, 2009, p. 5).

Another of Ms. McShane's samples, Scana, was recently downgraded on July 14, 2009 by Moody's due to factors related to a *"significantly higher business and operating risk profile"* primarily associated with a new nuclear construction project in South Carolina. [Transcript Oct 20, 2009, p. 143] Table 4 of the Scana Binder shows that Moody's downgraded Scana to Baa 2 from Baa 1 and also stated that the ratings outlooks for Scana and three of its subsidiaries were negative. FPL was clearly subject to political risks in Florida to the point that Moody's issued a statement in October of 2009 stating that it viewed *"the highly politicized atmosphere"* as a negative to the credit quality of FPL. [Oct 21, 2009, p. 12] Vectren, which has a significant portion of its gas and electric utility sales in space heating and cooling, does not have a weather normalization mechanism for its electric operations and therefore the company reports that *"significant variations from normal weather could have a material impact on its earnings."* [Oct 20, 2009, p. 123 and 123]

It is submitted that not a single one of Ms. McShane's US companies operate in such a supportive and protective environment as does NP. NP receives pre-approval of capital budgets and has weather-normalization, DMIA, ESCV, PEVDA, RSA, MSA, exceptional regulation, the ability to bring on *ad hoc* applications for relief, and no history of disallowances or political risk. Having canvassed the several US utility holding companies in Ms. McShane's sample, this simple question was posed, *"Now, Ms. McShane, where is the business risk for the investor in Newfoundland Power."* [p. 59 - Oct 21, 2009] Certainly, the first part of Ms. McShane's response is very telling:

> *"A. <u>Well, I mean, just because the utility has not experienced a risk doesn't mean that the risks aren't there</u>. I grant you that this company has been relatively stable and they've got a good supportive regulatory environment, but there are still long term risks to the company and when you try to figure out what the cost to capital is for a company or utility, you need to look at proxy companies, and I noted that these companies aren't an identical risk to Newfoundland Power, but they are the closest proxies, in addition to the Canadian companies that I've looked at, that are available. I mean, this is the process we all go through to try to figure out what the estimate of a cost to capital for a utility is. Newfoundland Power is not publicly traded."* (emphasis added)

Clearly, the objective evidence is overwhelming in this proceeding that risks for NP have not materialized. Dr. Booth's Regulatory Framework and Business Risk analysis (at Appendix H) emphasizes (p. 17) *"that risk means the probability of incurring harm, which in a financial sense is losing money."* Dr. Booth notes at p. 16 that it has been 14 years since NP last failed to earn its allowed ROE and over this period its average overearning is 57 bps, whereas since 1990 it is 21 bps. [see also CA-NP-28 - Attachment "A"]

Ms. McShane's statement that 'just because the utility has not experienced a risk doesn't mean that the risks aren't there' is a classic illustration of the type of phenomenon that Dr. Booth refers to in his report at p. 21:

> *"Further, I have heard many company witnesses discuss "increases" in risk faced by various regulated utilities since I first testified in 1985. However, the ability of Canadian regulated utilities to earn their allowed ROE has not been impaired and* *<u>I have yet to see any of these risks materialize to significantly harm a Canadian utility. In this respect it is my judgment that the risks brought forward on behalf of utilities have, or will be, largely transferred to ratepayers if and when they ever materialize</u>.* (emphasis added)
>
> *The history of regulation in Canada is that when risks arise to potentially cause losses to utilities they are invariably transferred to rate payers as part of the dynamics of regulation."*

One need look no further than a Fortis Annual Report to recognize that equity investors in utilities have a deep and abiding interest in the supportiveness of the regulatory regime. Fortis Inc. in its 2008 Annual Report [CA-NP-58, Attachment "C"] leaves no doubt as to the importance it places upon the factor of regulatory risk. In the MD&A (p. 25) Fortis Inc. states unequivocally:

> *"The key business to Fortis is regulatory risk."*

Shareholders of Fortis were advised at p. 25 of the 2008 Annual Report that *"the relationship of Belize Electricity became tenuous in 2008 when the regulator issued a decision disallowing previously incurred fuel and purchased power costs and lowering the regulated ROA"*. At page 35 it indicates that $18 million of fuel and purchased power costs were disallowed of which the company had a 70% obligation.

Fortis Inc. also points out to its shareholders (see p. 55) that the regularly frameworks in Alberta and Ontario have undergone significant changes since the deregulation of electricity generation and the introduction of retail competition. Fortis Inc. states,

> *"The regulations and market rules in these jurisdictions which govern the competitive wholesale and retail electricity markets, are relatively new and there may be significant changes in these regulations and market rules that could adversely affect the ability of Fortis Alberta and Fortis Ontario to recover costs or to earn reasonable returns on capital. As these companies and their applicable regulators work through the regulatory processes, it is expected that there will be more certainty involving regulatory frameworks and environments."*

The key business risk identified by Fortis Inc. - Regulatory Risk - is nothing but a positive for NP's shareholders, as exemplified by Moody's latest rating report and by Mr. Cicchetti's remarkable characterizations of the regulatory regime in this province.

In summary, Ms. McShane's evidence serves more as a reminder of why US ROEs have no discernible applicability to NP. Her US comparables analysis is the major factor in explaining why her ROE recommendation for NP is a gross overstatement.

<u>The Risk Adjusted Market Risk Premium</u>

Ms. McShane's report at p. 43 discusses the Risk Adjusted Market Risk Premium Test. As noted, this is one of the three Equity Risk Premium Tests that Ms. McShane develops in her evidence - the others being the DCF-Based Equity Risk Premium Test and the Historic Utility Equity Risk Premium Test.

It may be useful to set out what each of the three tests of Ms. McShane produces in terms of a risk premium.

Risk-Adjusted Equity Market Risk Premium Test	*Risk Free Rate*	*Risk Premium*
	4.25	**6.75*

**6.75 x beta of .65 - .70 (report, p. 55, line 1375)*

yields an indicated utility risk premium of approximately 4.5% - therefore the cost of equity based on the risk adjusted equity market risk premium test at the 2010 forecast long term Canadian bond yield of 4.25% is 8.75%, before any adjustment for financing flexibility.

DCF - Based Equity Risk Premium Test	*Risk Free Rate*	*Risk Premium*
	4.25%	**5.4%*
Version 1 **see p. 58, lines 1445-6 of Ms. McShane's report.*		
Version 2 - (which considers "A" spreads) ***see p. 59, lines 1489-1490 of Ms. McShane's report.*	*4.25%*	***6.0%*
****as updated on October 21, 2009* *(at p. 81, Line 13 of transcript of Oct 21, 2009)*	*4.25%*	****5.3%*

Historic Utility Equity Risk Premiums	*Risk Free Rate*	*Risk Premium*
	4.25%	*6.25%*

As seen above, Ms. McShane's Risk Adjusted Equity Market Risk Premium produces a Risk Premium of 6.75%.

Dr. Booth in his direct evidence to the Board on October 21, 2009 provided an encapsulation of his views of this 6.75% estimate of Ms. McShane's (from pages 152 to 159). Dr. Booth also addresses Ms. McShane's 6.75% market risk premium from pages 47 to 49 of his report. Notably, both experts agree that the historic market risk premium has been 4.6% in Canada and 5.6% in the US. Ms. McShane then looks at the nominal equity returns in the US and Canada from 1924, which she estimates at 11.3% for Canada and 11.7% for the US. Here again there is a little dispute as to these estimates from Dr. Booth since he estimated them to be 11.1% and 11.66% respectively in his Appendix F. After this, Dr. Booth and Ms. McShane part company. As Dr. Booth put it at p. 48 of his report:

> *"However she subtracts her current short and long run LTC yield forecasts of 4.25% and 5.25% from these long run average equity returns to get her market risk premium estimate of approximately 6.75%.*
>
> *It is not immediately obvious where Ms. McShane's 6.75% comes from, but the more important question is the procedure itself. I don't believe you can subtract the current LTC yield from a long run average equity return since it mismatches the underlying inflationary environments. The current LTC yield reflects the current inflationary forecast of 2.0% and the current operating procedures of the Bank of Canada. In contrast the average return of 11.3% in Canada reflects the entire inflationary period from 1924. My appendix E shows that inflation averaged not 2.0% but over 3.0% during this period, so her procedures may over estimate the market risk premium by at least 1.0%."*

Dr. Booth acknowledges that the data of the historic risk premiums in Canada and the US has to be interpreted and that involves judgment *"in terms of how do we interpret that data and how do we make adjustments in terms of a going forward market risk premium..."* (P. 153-4 of Oct 21) This is where Dr. Booth introduced the evidence from the survey of 884 finance professors, carried out by Professor Pablo Fernandez in the January-February period of 2009. Table 2 at p. 48 of Dr. Booth's report provides the results. As Dr. Booth stated on direct (at p. 156):

> *"There's a couple [of finance professors] down there at two percent and three percent and there's a couple up there at seven percent and eight percent, but overwhelmingly, the professional judgment of professors of finance in Canada is the market risk premium is five or six percent. So I think that's judgment that's constrained by the historic evidence, by their expertise in teaching and cases and looking at research in the market risk premium."*

Dr. Booth stated at p. 155 (Oct 21, 2009):

> *"The critical number is the median, the middle guy. The middle guy in the US*

thinks the market risk premium is six percent. The middle guy in Canada thinks that it's 5.1 percent. The middle guy in Europe thinks it's five percent. The middle guy in the UK thinks it's five percent. I think it's five percent. So one important fact is that my estimate of the market risk premium is not a high ball, it's not a low ball. It's basically right in the middle of the pack."

In fact, in Canada the median response in the survey was 5.1% in Canada and 6.0% in the US, well below Ms. McShane's estimate of 6.75%. With respect, Ms. McShane's estimate of a 6.75% MRP is an overstatement of the MRP.

Ms. McShane's Use of Adjusted Betas

As explained during cross-examination (Oct 21, p. 96-101) Ms. McShane next takes her estimate of the Market Risk Premium of 6.75% and multiplies it by a beta of .65 to .70 - which she explained *"is trying to represent what percentage of the market risk premium utility investors reasonably expect to earn."* (P. 97) She explained that that "beta" number of .65 to .70 is *"conceptually a raw beta adjusted."* Ms. McShane referred to Table 8 of her evidence which showed the "Raw" betas across 5 different utility companies to have a median of .47. She explained on cross-examination that the term "Raw Betas" was not a term of art, *"It's probably a McShane term."* (P. 100) The cross-examination concluded as follows, at p. 101:

"Q. *Just one more question before the break. The use of adjusted betas, Ms. McShane, I think your reply to CA-NP-16H, where we asked for you to provide citations to any and all Canadian regulatory decisions that have approved the use of adjusted betas by squashing them with 1.0 as indicated on page 54. That's the reply there that we can read it, that you're not aware of any Canadian decisions which have specifically relied on the adjustment methodology?*

Ms. McShane:
A. No, I'm not."

With respect, we do not believe that there is a basis for this Board to accept Ms. McShane's adjusted beta approach in this case either. This matter is further addressed in the section of this submission pertaining to Dr. Booth.

Dr. Laurence Booth

Dr. Booth, it is submitted, is highly qualified by virtue of his education, training, research and experience to provide his opinion to this Board. Specifically, the Consumer Advocate asked Dr. Booth to review NP's rate application and associated evidence and to offer an opinion as to the fair rate of return on common equity and appropriate capital structure for NP and whether the ROE adjustment mechanism continues to be appropriate.

As will appear by his C.V. at Appendix "A" to his Pre-filed Evidence, Dr. Booth is a Professor of Finance at the Rotman School of Management at the University of Toronto where he holds the CIT Chair in Structured Finance, a Chair he has held since 1999.

Dr. Booth is a graduate of the London School of Economics and holds a Masters Degree in Business Administration and a Doctorate in Business Administration from Indiana University.

Dr. Booth's main research interests centre on the cost of capital, international corporate finance and capital market theory. His main teaching interest is domestic and international corporate finance.

Dr. Booth's C.V. demonstrates that he has published numerous papers in a variety of academic journals, including papers specifically dealing with the Cost of Equity Capital, Canadian Capital Market History, Estimation of Risk Premiums, Risk and Return in Capital Markets and Equity Risk Premiums in the US and Canada. Dr. Booth has also authored or co-authored a large number of non-journal publications.

In addition, Dr. Booth has prepared evidence and testified as an expert financial witness before utility regulators across Canada.

Dr. Booth's Pre-filed Evidence is comprehensive, covering some 98 pages in addition to schedules 1 to 30 and Appendices A to H together with their own schedules.

Dr. Booth testified over parts of October 21 and 22, 2009. For ease of reference, the following references are provided:

<u>October 20th</u>	from pages 130 to page 184, Dr. Booth provided an overview of his evidence during his direct examination;
	from pages 184 - 208, Dr. Booth was cross-examined by NP's counsel.
<u>October 21st</u>	from page 1 to page 53, Dr. Booth's cross-examination by NP's counsel continued;
	from pages 53 to 86, Dr. Booth was cross-examined by Board Hearing Counsel;
	from pages 86 to 98, Dr. Booth was questioned by the Board Members;

and

from pages 98 to 102, Dr. Booth was re-examined by the Consumer Advocate.

The Consumer Advocate submits that Dr. Booth testified in a clear, cogent and direct manner. That was very evident to anyone who heard Dr. Booth testify before the Board. In our submission, Dr. Booth was an expert witness, who was very helpful to the Board in terms of the tasks that the Board has before it in this case.

No attempt will be made to try to encapsulate all of what Dr. Booth had to say to the Board both in his pre-filed evidence and *vive voce* testimony. Indeed, we have also made reference to Dr. Booth's evidence in connection with other sections of this Submission. However, we would propose to focus in on the following key points arising from Dr. Booth's evidence:

- Recommended Allowed Return
- Equity Risk Premium Test
- Market Risk Premium
- Beta Estimate
- Can US Utility ROEs be Compared to Canadian without Adjustment?
-

<u>Recommended Allowed Return - 7.75%</u>

Dr. Booth's fair return estimate for NP is 7.50% inclusive of a .50% flotation or issue cost and based upon a 300 basis point utility risk premium over a 4.50% forecast long Canada bond yield. [Pre-filed Evidence - p. 56] Dr. Booth, at p. 56, notes that he would also take into consideration a margin of error. Dr. Booth recommends a fair ROE of 7.75%. Dr. Booth explains this as follows at page 56:

> "A. *My recommendation is based on estimates and these always have some measurement error attached to them. As I noted previously the Fernandez article has indicated to me that most Canadian finance professors use 5.0% or 6.0% for the market risk premium. So with a beta of 0.50 this means that in all likelihood another Canadian finance professor might have estimated a fair return 0.50% higher than my estimate. However, when I look at the betas for utilities, either individual companies or the utility sub indexes, it is difficult to see how anyone could estimate a beta for a Canadian utility higher than my .45-0.55 range. Adjusting for the Bell Canada effect we simply haven't seen betas consistently outside of this range for 20 years.*
>
> *So overall I would indicate that the martin of error in my estimates might be 0.50% which means 7.50-8.0%. Taking the mid point I would recommend a fair ROE of 7.75%."*

Equity Risk Premium Test

For reference purposes, Dr. Booth addresses his estimation technique on October 21, 2009 at pages 148 - 151.

Dr. Booth's report addresses CAPM in his report from p. 31 to 40. He also estimates using a two factor model of CAPM at p. 40 to 41.

CA-PUB-6 confirms that RH1 2008, the NEB's most recent decision based its recommended award exclusively on the CAPM.

CAPM is overwhelmingly the most important model used by a company in estimating the cost of equity capital. [Report p. 32, lines 18 - 20] A survey published in the Journal of

Financial Economics of some 392 US CFOs bears this out and is graphically presented at p. 33 of Dr. Booth's report.

This Board has relied principally on the equity risk premium test for a number of years going back to at least PU 16 (1998-99).

Market Risk Premium

From page 46 to 47 of his Pre-filed Evidence, Dr. Booth addresses his reasons for stating that the Market Risk Premium is 5.0%. Dr. Booth states that since 1956 the Canadian market risk premium of equities over long-term bonds has been in a range of 1.69 - 2.16%. Extending the data back to 1924 increases the range to 4.70 - 4.76%. Dr. Booth currently estimates the market risk premium at 5.0%.

Dr. Booth then addresses (p. 47-49) his estimate of the MRP at 5.00% versus Ms. McShane's estimate of 6.75%. This issue is addressed in greater detail in this Submission's discussion of Ms. McShane's evidence.

Suffice it to say that the Consumer Advocate views Dr. Booth's estimate as more in keeping with the preponderance of received professional judgment as noted in the Fernandez survey at p. 48 of Dr. Booth's report. The survey does provide a reality check.

Dr. Booth also pointed out to NP's counsel on cross-examination (p. 7 - Oct 22, 2009) that his report also includes evidence of the market risk premium or expected rates of return by the TD Bank and the Royal Bank of Canada.

Beta Estimate

Dr. Booth uses a reasonable beta estimate of .50 (Pre-filed Evidence, p. 47, line 20).

Dr. Booth notes (at p. 53) that Ms. McShane uses a beta adjustment on the thinking that it is better to "squash" or average the actual beta with 1.0 to get a forecast beta. Dr. Booth's report states:

> *"This is the basis of the beta adjustment formula used by people like Bloomberg, Merrill Lynch and others. However, this does not hold for utilities for the simple reason that they are not randomly chosen stocks whose beta is assumed to be 1.0. Instead we know that they are low risk with an average beta of about.50. As a result their regression tendency is that their will revert to their mean of .50."*

CA-NP-16 (h) confirms that Ms. McShane is not aware of any Canadian decisions which have specifically relied on the adjustment mechanism which she employs in her evidence for NP.

Dr. Booth notes (p. 53) that in addition to the reply of Ms. McShane to CA-NP-16:

> *"She could have pointed to the recent National Energy Board's TQM decision where they stated that they were not convinced that TQM had demonstrated that utility betas revert to 1.0. 'an assumption on which adjusted betas rely.' Since there is no empirical or theoretical evidence that utility betas revert to 1.0 and they have never been accepted by a Canadian regulator I fail to see why the Board should accept 'adjusted betas'."*

Dr. Booth's discussion of his beta analysis takes place in his report from p. 31 to 46. We would also direct the Board to Dr. Booth's direct testimony on October 21st, from page 159, line 9 to page 163 for a further exposition of his beta estimate.

Dr. Booth made the point (Oct 21, 2009, p. 161) that "you have to understand where those statistics come from, and they're just reflecting what actually happened in the capital market over these periods." Utility stock are defensive stocks or low risk stocks. They don't increase with the market. They don't drop with the rest of the market. They are not as volatile as the market as a whole. Mr. Cicchetti stated that utility stocks are considered "widows and orphans stocks". [Oct 22, 2009, p. 111, line 25]

Dr. Booth states at p. 161 - 162 of his direct:

> *"When we go through it and get the 2009 data, we're going to end up getting lower estimates for the betas for utilities reflecting the fact that they're low risk stocks. So you have to look at the data and not just say well, I don't like those statistics.*
>
> *You have to understand where those statistics come from, and they're just reflecting what actually happened in the capital market over those periods.*
>
> *I also, just to backdrop in terms of price performance over the last year, I tracked the price performance on pages 43 to 45, and this is not rocket science. This is just going to yahoo.com, plugging in what's happened to the TSX index, where the GFP TSE is, the Toronto Stock exchange composite index, plugging in the prices for most of the big six Canadian utilities and just graphing the price performance. So if these were as risky as the market as a whole, you'd expect them to behave like the market. What's pretty obvious from looking at these price charts is Emera, for example, when the stock market collapsed 40 percent, Emera was down 15 percent possibly in March 2009 and the same thing with Fortis. Fortis barely never dropped more than 20 percent when the market was off 40 percent, and we could look throughout all of the utilities and we can see what comes through very, very clearly is they're simply not as volatile as the market as a whole. They just don't drop with the market. They don't increase with the market, which is what we call defensive stocks or low risk stocks. So there's absolutely no question that the price behaviour of utility holding companies in Canada has demonstrated, yet again, that they're low risk. They're low beta stocks. They're defensive stock. So I have no problem looking at that. There are always problems with individual beta estimates because of unique things that are happening to firms, but overall what comes through clear as a bell is the low risk nature of utility stocks, the overall market risk premium, five percent, possibly six percent."*

<u>Can US Utility ROEs be Compared to Canadian without Adjustment?</u>

Ms. McShane and Mr. Cicchetti do not make any adjustments for application to NP in this case. This represents their judgment.

In regard to Dr. Booth's judgment on this point we would refer the Board to Dr. Booth's direct testimony of October 21, 2009 at p. 173 to 180. Dr. Booth notes that he has taught international finance for 15 years and the basic rule is that you cannot take interest rates or fair rates of return from one market and apply them to another without making serious adjustments. Dr. Booth stated that it "violates everything I've been teaching in international finance to accept evidence from the US without making adjustments". It is clear that market integration simply means that capital can flow freely between two markets but that does <u>not</u> mean that the rate of inflation or that risk is the same. [CA-PUB-15 (c)]

Dr. Booth pointed out that though Canadian and US utilities use the same underlying technology, pipes and wires, the "absolutely critical" piece is the overall philosophy of regulation. In the US utilities can "get hurt". In Canada, utilities are well-protected. Moody's recognizes it very expressly. There is also more "event risk" in the US.

Finally, there is the big "macro picture" as Dr. Booth puts it. 15 years ago Canada had higher inflation and bigger deficits. Today, Canadian finances are strong. The US is not in the same situation - with deficits presently running 13% of GDP. Prime in Canada is at least one percent lower than in the US. Dr. Booth concluded at page 179:

> *"So benchmarking against the United States, given all the sacrifices and the achievements that we've got in Canada, to me just doesn't make any sense. The US may be used as a comparable to look for signals, but you have to make adjustments."*

Interest Coverage - Considerations

In PU 19 (2003) at p. 42, the Board addressed the *"Relationship between Capital Structure, Return on Equity and Interest Coverage"*. The Board stated:

> *"Capital structure is the mix of debt and equity invested in a company with debt representing the investment of bondholders or other long-term debt holders and equity representing the investment of shareholders, in either common or preferred stock.*
>
> *The relationship between capital structure, return on equity and interest coverage is a key element in any cost of capital determination.*
>
> *Interest coverage represents the ability of a company to meet its debt obligations and is derived as a ratio of earnings before interest and taxes to annual interest charges. Interest coverage is a prime ratio used by credit rating agencies in measuring the creditworthiness of a company since it reflects both the earnings capacity of the company and how well its capital structure or indebtedness is managed.*
>
> *Return on equity (ROE) is a ratio of a company's net income or earnings (less any preferred dividends paid) to the shareholders' common stock equity or investment. ROE essentially is the measure of earnings available to common shareholders compared to their investment."*

At page 53 of its decision the Board observed that interest coverage represents essentially an arithmetic determination which is a function of the company's capital structure, in particular its debt level, and the ROE reflecting the ability of the company's earnings to cover or meet these debt obligations. The Board noted at p. 54 that it *"does not regulate interest coverage."*

As the Board is aware, NP has provided as Table 3-10 its Credit Metrics: 2007 to 2010E as follows:

Table 3-10
Credit Metrics: 2007 to 2010E

	2007	2008	2009	2010E
Pre-tax Interest Coverage (times)	**2.2**	**2.5**	**2.3**	**2.0**
Cash Flow Interest Coverage (times)	**2.6**	**3.1**	**3.1**	**2.8**
Cash Flow Debt Coverage (%)	**12.6**	**15.8**	**15.4**	**13.1**

Exhibit 11 shows the Rate of Return and Credit Metrics if NP's Application proposals are granted:

Rate of Return and Credit Metrics	2010 Proposed
Rate of Return on Rate Base (percentage)	9.13%
Regulated Return on Book Equity (percentage)	11.00%
Return on Book Equity (percentage)	10.70%
Interest Coverage (times)	2.7
CFO Pre-W/C + Interest / Interest (times)	3.6
CFP Pre-W/C / Debt (percentage)	19.5%

NP has provided as Exhibit 5 a series of metrices charts into which one may *"plug in"* a given ROE. Indeed, Mr. Cicchetti notes at p. 25 of his report that his ROE recommendation would produce certain ratios by reference to the charts in Exhibit 5.

A caution is required here. Dr. Booth has stated in reply to PUB-CA-6 that he is not aware of any financial theory or practice that states that a particular times interest earned (TIE) ratio is fair and then keys the allowed ROE off that TIE and the other variables that jointly determine it. Dr. Booth explains,

> *"For example if the board feels that a TIE of 2.5 is "needed" for some reason and the tax rate drops it is patently unfair to award a higher ROE to offset what would otherwise be a drop in the TIE. Similarly it is patently unfair to award a higher ROE for one utility with a higher embedded debt cost (R) compared to another utility that has managed its debt issues more efficiently and has a lower embedded debt cost.*
>
> *The equity holders should be awarded a fair and reasonable ROE and that is independent of any particular TIE. The TIE is only relevant when it comes to debt market access and with NP recently upgraded by Moody's to A and still at A with DBRS it has just about the best debt market access of any Canadian utility."*

Mr. Simmons (Oct 22, 2009, p. 82 - 85) asked Dr. Booth whether he considers the impact that his ROE recommendation would have on the capacity of the utility to borrow on its credit standing, rating, and credit metrics. Dr. Booth affirmed that the critical thing we look at is whether the rate of return is fair and reasonable. We then have to look at whether or not the firm can raise capital and provide service. Dr. Booth stated that normally, any fair rate of return is going to imply that the utility's financial integrity is preserved. Dr. Booth referred to the situation of Enbridge which lacks a weather normalization account and therefore has volatile earnings. It has faced a problem of its fair return not meeting its requirements to raise long term debt. Dr. Booth stated at p. 84:

> *"So in those cases, you look at it and you say well, if the equity return is fair, how can we cope with this problem of maintaining financial integrity, access, raising capital to provide financing, and the answer to that is not to reward the equity holders because these concerns generally got nothing to do with the equity holders. So you don't give the equity holders a bonus return simply because of temporary financial access problems. What you do there is you look at the ability of the firm to raise short term debt, and in the case of Newfoundland, that's not a problem because they've got extensive short term credit facilities, and, in fact, according to Moody's, they're just had the material adverse conditions clause removed from their credit line. So that means they can do what small utilities or smaller utilities generally do, which is borrow short term, and wait to refund when the market conditions are appropriate. Generally in those conditions, I look to see the availability of the short term capital, and if there's a persistent problem, and this is what I recommended before the Ontario Energy Board, the traditional solution is preferred shares. You use preferred*

shares on a temporary basis because preferred shares boost the interest coverage ratio, allows the firm better access to financial markets, and doesn't reward the equity holders, and I've constantly said for the last ten years you don't reward the equity holders for problems in the bond market in terms of coverage ratios and access in financial markets, because those are just technical restrictions and nothing to do with the fair rate of return standard."

In PU 19 (2003) the Board arrived at a fair ROE for NP at 9.75% based upon a Risk Free Rate of 5.60% and Risk premium of 4.15%. The Board stated that it does not regulate interest coverage but noted that the resulting coverage was 2.4x, within the range previously accepted by the board in PU 16 (1998-99), though at its lower end. The Board noted that NP indicated that it would not be going to the bond market again until 2006. (In this GRA hearing Ms. Perry confirmed that NP's next bond issue is expected in June of 2012 - see Oct 19, 2009, p. 10-11) The Board rejected NP's argument for a higher coverage stating at p. 54:

"The Board does not accept that an ROE of 75-100 basis points higher than the 9.75% deemed fair and reasonable by the Board is warranted in order to sustain a 2.5x interest coverage based on a capital structure that ranks amongst the most favourable when compared to utilities of equivalent risk.

NP's CFO, Ms. Perry, was extensively referred during cross-examination to the Moody's Methodology Documents of 2005 and 2009. Indeed it was the 2005 Methodology document that was specifically cited in the August 3, 2009 Moody's Release (see Exhibit 4) which upgraded NP's FMBs to A2 (from Baa 1) and assigned a Baa 1 Issuer rating to NP. Specifically, the Release stated:

"The principal methodology used in rating NPI is the March 2005 Global Regulated Electric Utilities methodology, which can be found at www.moodys.com in the Credit Policy & Methodologies directory, under the Ratings Methodologies Subdirectory."

The 2005 Methodology at p. 7 states that Moody's uses financial ratio analysis as part of their quantitative analysis of all corporates, including electric utilities. But Moody's also makes it clear that ratio analysis must put in a proper context. As Moody's puts it:

> *"However, the importance of ratio analysis can be overstated. No two companies look exactly alike from a qualitative assessment standpoint and each company we rate is constantly changing. It is impossible to assign an accurate credit rating on the basis of financial ratio analysis alone, even less so on the basis of any one ratio. Therefore, Moody's does not have any specific "hurdle rate" to explain which ratio will make the difference between any two rating categories."*

It is clear from Moody's Credit Opinion of 6 March 2009 that Moody's is well aware that NP's ratios *"generally continue to be somewhat weaker than those of Baa 1 - rated peers predominantly engaged in T&D such as Atlantic City Electric Company (ACE), Connecticut Light and Power (CLP) and Fortis Alberta Inc. (FAB), a sister company."* In fact, Moody's expects that NP will continue to have somewhat weaker ratios. Moody's goes on to state on the 2nd page of the opinion that,

> *"ACE and FAB has reported CFO pre-WC to debt in the 15 to 20% range versus NPI's 15% level. Similarly, ACE, CLP and FAB have reported CFO pre-WC interest coverage in the 4x range versus NPI's sub - 3x range in recent years. In general, Moody's anticipates that NPI's CFO pre-WC to debt will remain in the 15 to 16% range while its CFO pre-WC interest coverage stays above 3x going forward."*

In fact, the March 2009 Opinion makes it clear that,

> *"NPI's relatively weaker financial profile is offset by the company's location in a supportive regulatory environment with a regulatory construct that permits it to over or under earn within a band of plus or minus 18 basis points of its allowed return on ratebase."*

Moody's goes on to refer to the various regulatory mechanisms that limit NP's exposure to risk. Two observations are appropriate here:

1) the "offsetting effect" of NP's supportive regulatory environment is completely consistent with the 2005 Methodology approach;

2) the fact that Moody's refers to the +18 basis point band in NP's AAF as being a supportive regulatory construct has implications for NP's desire to discontinue the AAF.

NP's VP Finance, Jocelyn Perry, appeared to be of the understanding that Moody's would not accept NP having lower financial metrics *"within our peer group"*. [Ref Oct 15, p. 116] Clearly, the foregoing analysis establishes that Ms. Perry was obviously mistaken. Clearly, it is the very important qualitative factors, plus NP's *"45% deemed equity component [which] is amongst the highest for Moody's-rated electric utilities in Canada"* that is taken into account.

On the first page of the March 2009 Moody's Opinion, Moody's sets out the following ratio data for 2004 to 2008:

	2008	2007	2006	2005	2004
(CFO Pre-W/C + Interest Expense) / Interest Expense (x)	3.1x	2.6x	2.7x	2.9x	3.0x
(CFO Pre-W/C) / Debt (%)	15.8%	12.6%	13.9%	15.7%	16.0%
(CFO Pre-W/C - Dividends) / Debt (%)	12.4%	10.6%	9.6%	10.1%	12.5%
(Debt / Book Capitalization (%)	54.4%	55.9%	55.8%	[3]63.18%	55.5%

It will be noted that Moody's does not specifically report or comment upon the Pre-tax Interest Coverage Ratio that NP has set out in Table 3-10. It will also be noted from Moody's comments which we just reviewed pertaining to NP's peers' ratios that NP has indeed had its ratios significantly lower that of its peers.

Also notable is the fact that Moody's is certainly not indicating that it expects NP's ratios to improve to the point of relative parity with its peers on a go-forward basis. To be sure, NP's long-term ratings *"<u>could be positively impacted</u> if NPI could demonstrate sustainable improvement in financial ratios such as CRP pre-WC interest coverage above 4.0% and CFO pre-WC to debt in the high teens."* But that is not Moody's expectation.

One does observe on the other hand a material change in the language used by Moody's in its March 2009 Opinion compared to its March 5, 2007 Credit Opinion [entered as Information No. 4] in relation to *"What Could Change the Rating - Down."* The 2007 Opinion was entered as an exhibit in NP's 2008 GRA. It stated:

> *"What Could Change the Rating - Down*
>
> *NPI's rating could be negatively impacted if by 2008 CFO Pre-WC Interest Coverage has not met or exceeded* ***3.0x*** *and (CFO Pre-W/C) / Debt has not met or exceeded* ***15%****."*

By contrast, the March 2009 Opinion states:

> *"What Could Change the Rating - Down*
>
> *Moody's considers a downward revision in NPI's rating to be unlikely in the near term. However, NPI's long-term ratings could be negatively impacted to the extent that Moody's perceived a reduction in the level of regulatory support combined with weaker liquidity and sustained deterioration in NPI's credit metrics such as CFO pre-WC to interest coverage of less than* ***2.5x****, CFO pre-WC to debt in the* ***low teens*** *and debt to capitalization in excess of 55%."*

Ms. Perry did not appear to want to acknowledge that this represented an improvement in NP's perception by Moody's. [October 15, 2009, p. 154 - 156] Ms. Perry concluded by reiterating that *"our financial profile, as it is today, is still relatively weak compared to our peers, so that's important."* However, on October 15, 2009 when she was testifying, Ms. Perry was not aware that Moody's will indeed accept lower financial metrics from NP relative to its peer group. Ms. Perry testified that her understanding was in fact the opposite (p. 116, October 15, 2009) as evidenced in the following passage:

> *"Ms. Perry:*
>
> *A. . . . I would like to point out that this is just a methodology that's applied to all regulated and unregulated utilities. When we discuss with Moody's the assessment process for us, it takes into account that we are regulated, that we are in a supportive environment, but then they compare that - - they would assess - - they do rate us a low business risk; low being the fully regulated,*

medium being the regulated plus unregulated. So they would then assess all of the low risk utilities, which they consider to be the fully regulated utilities together. <u>So to say that they will accept lower financial metrics within our own peer group, I don't believe that to be the case, no</u>." (emphasis added)

Ms. Perry did acknowledge that NP's thickness in its equity component in its capital structure has been recognized by Moody's. At p. 167-168:

"Q. *. . . Newfoundland Power has a good degree more thickness in its equity component in its capital structure than most any other utility in the country, correct?*

A. *Moody's do make that point and that certainly has been supportive of keeping our investment grade credit rating, yes."*

Finally, Ms. Perry did acknowledge [Oct 15, 2009, p. 165] that Moody's would understand and appreciate that NP and other Canadian utilities have been operating for some time under formulas such as the AAF. Towards the conclusion of her testimony for October 15, 2009, Ms. Perry read the following extract from p. 27 of Moody's August 2009 Methodology into the record:

"Ms. Perry:

A. *'In Canada, regulation of electric and gas utilities is overseen by independent quasi-judicial provincial or territorial regulatory bodies. According, the transparent instability of regulations and the timeliness of regulatory decisions can vary by jurisdiction. However, generally the regulatory framework in each jurisdiction are well established and there's a high expectation of timely recovery of cost and investment. Furthermore, Moody's considers the overall business environment in Canada to be relatively more supportive and less litigious than that of the US. Moody's view: a business supportiveness of the Canadian business and regulatory environments to be positive for regulated utility credit quality and believe that these factors, to some degree, offset the relatively lower ROE's and higher deemed debt components typically allowed by Canadian regulatory bodies for rate making purposes. <u>As a result of the relatively low ROE's and higher deemed debt levels, there are generally characteristic of Canadian utilities for a given rating category, these entities often have weaker credit metrics than their international peers</u>."* (emphasis added)

AAF

It is important to contextualize NP's criticism of the AAF.

Ms. Perry's evidence is that there has not been a problem historically with the AAF for NP, but the problem is the effect that its use will have under "current market conditions". [Oct 21, 2009, p. 121]

Mr. Ludlow stated (October 19) at page 107:

> *"And as we filed we're proposing the discontinuance of the AAF until such time, either the market settles or whatever conditions can occur as we move to the future."*

Ms. Perry stated (p. 107 - 108):

> *"Yes, I think when we look forward at the formula when we were filing the Application, we were seeing a decrease in the cost of equity coming out of the formula and certainly this was at a time when our cost of debt was going up. So - - and albeit the markets have improved somewhat since we filed, our cost of debt is certainly not going down though from previous levels, so the fact that we are experiencing historical low long-Canada bond yields and the fact that we are projecting a declining cost of equity, that relationship was flawed when we filed and today."*

Here we would commend to the Board the evidence from Dr. Booth's direct testimony on October 21, 2009 from page 164 to 173 as well as his cross-examination from pages 43 to 69 on October 22, 2009.

Dr. Booth pointed out that he can fully understand given the depth of the economic problems last Fall, why utilities were seeking to have AAMs reviewed (Oct 22, p. 44). Dr. Booth testified that:

> *". . . the crisis last fall was the worse we've seen in 71 years and when you severely damage the financial system, you damage the whole economy, and that's what precipitated the Great Depression, it precipitated analogies with the Great Depression too lost fall, and I can fully understand why in that situation why the utilities would say this is a seismic change in the markets, let's see whether the Automatic Adjustment Mechanism and the ROE is still fair. So I can understand why the utilities did that."*

But Dr. Booth was clear that the crisis is now in the past. At page 57 (Oct 22, 2009) of his examination by Board Hearing Counsel, Dr. Booth referred to the measures that have been taken in the US in the banking industry. Liquidity spreads or the credit spreads in the short term market have come down. The economies of the US and Canada are recovering. It is worth setting out what Dr. Booth stated from pp. 57 to 60 given its pertinence to his assessment of the current situation:

> "... *We're no longer in this situation of uncertainty where we didn't know what was going to happen. We're now back to a normal business cycle, and as I indicated to Mr. Kelly, I think the A spreads are still high from where I would expect at this stage in the business cycle, but they're not dramatically higher. So I would say at this stage - - would I adjust the adjustment formula simply because "A" spreads are possibly 15/20 basis points higher than I would have expected them at this stage; the answer to that is no, not really. I don't see that as being significant enough to adjust the ROE formula because even if you assume all of that is due to a risk premium, you're talking about 15/20 basis points, tops, and that is not all due to a risk premium, it's due to other factors in the bond market.*
>
> *Mr. Simmons:*
> Q. *So in 2010, which is going to be contemplated to be the test year on this application, we can expect there are still going to be some effects lingering from the economic crisis that happened in '08, into early '09, and those effects will have to be taken into account when the rate of return on equity and the rate of return on rate base is set for 2010, but if you are correct, after 2010, you are expecting the financial markets to return to more of a normal situation?*
>
> *Dr. Booth:*
> A. *<u>I think they're returning to normal now, so I wouldn't put it off to 2011.</u> In my judgment, 2010 is going to be a normal recovery year, and right now we're seeing forecasts - - for example, people expect earnings forecast for most major corporations to now be beaten by the companies because as you get into the upswing in the economy, firms beat the earnings forecast because they downsized a lot of their fixed costs and once you get a recovery, you et a quick uptake in earnings, and I would expect 2010 to be recovery year, 2011 will be back to normal, but as I said in my direct, normal is not good. I mean, normal is, given the stage in the business cycle, what's normal. People seem to think that normal is 2005, 2006, 2007. Those were not normal. That was*

the top of the business cycle, and that's just as abnormal as the bottom of the business cycle. Right now we're early in the business cycle compared to 2002 and 2003 when the ROE was litigated because we had just come out of a very bad recession, but we're on the upswing, and things are pretty close to normal compared to where we are in the business cycle. As I've said, spreads from probably 15 to 20 basis points higher, but it's not - - most of the lingering problems from the six month period from September to March, '09, have been dealt with. Unless we discover that the US banks have got a lot more liabilities and a lot more debts to write off, and they're written off, close to a trillion dollars worldwide, it's close to 1.3 trillion dollars in bad debts have been written off. That's a huge amount of money and there can't be that many bad debts left in the US financial system. So assuming that they've written off enough and that there's not a double dip, it's difficult to see how you can have any more lingering effects from the financial crisis. So I would say we're back to normal, given the stage in the business cycle, which is the fact that we're still in an uptake."

As noted above by Dr. Booth, 2005, 2006 and 2007 were the top of the business cycle. In its Finance Evidence (p. 3-13) NP refers to the spread on its May 29, 2009 FMB and notes that the interest rate of 6.61% was based on a credit spread of 2.75% over 30-year Government of Canada bonds. The company evidence states, *"This compares to credit spreads associated with First Mortgage Bond issues of 1.40% in 2007 and 1.06% in 2005. The 2009 increased credit spread reflects <u>current financial market and conditions</u>."* (emphasis added) Ms. Perry testified (Oct 15, p. 49) that indicative pricing from the Bank of Montreal in early October showed an indicative spread of 187 basis points. Undertaking 2 was subsequently filed in respect of this issue by NP. Ms. Perry confirmed that when NP issued a $75 million bond in the fall of 2002, the spread was 185 basis points over the risk-free rate. [p. 50, Oct 15, 2009]

Dr. Booth testified (p. 168 , Oct 21, 2009) that he believes that the AAMs or AAFs have reflected the correct trend over the past 15 years:

"Mr. Johnson:

Q. So you support the continued use of the ROE adjustment mechanism, do you Dr. Booth?

Dr. Booth:

A. *Yes, I do. There's two things to look at. One, is the overall trend and if you look at the yield on the real return bond in Schedule 18 to my testimony, you'll see that when these adjustment mechanisms were introduced in the early 90s, '93, '94 BCUC, NEB and then the Manitoba PUB, the real return on the long-Canada bond was four and a half percent, so this is the return on the real return bond. Since then, as it's got its financing under control, the risk has dissipated and long-Canada bond yields for the real return bond have dropped down to the two percent level. So there's been about a two and a half percent drop in the real interest rate on the real return bond and all else constant, that would mean that the risk premium, the market risk premium would have bone up by that amount and if the Beta is .5 as I estimate, the utilities fair rate of return, the risk premium, would have gone up by 125 basis points. By happenstance that is exactly what's happened as a result of the NEB's formula that a utility risk premium has gone up by about 125 basis points since 1994. So I think that the direction of the trend, as a result of the ROE Adjustment Formula, has been absolutely correct over the last fifteen years. That does not mean to say that it's correct in a mechanical way on an annual basis, so I've never said that it's absolutely correct. No mechanical forecast can be absolutely correct, it's going to over and under predict slightly over the business cycle and that's why I have no objection to supporting the continuation of the ROE Adjustment Formula, even though it's 40 or 50 basis points higher than what I think is a fair ROE. I think as far as people are concerned it's marginally higher, but if it does away with repetitive ROE testimony and clears the slate for regulators to do other thinks, then I think overall that's a good bargain for all concerned. So I think overall the direction of the ROE formula has been absolutely correct, but it doesn't mean to say that it's absolutely correct on a year-to-year basis, given changes in the capital markets."*

The AAF was last reviewed by the Board in PU 32 (2007) and it was found to be appropriate both in terms of regulatory efficiency and greater regulatory predictability and certainty.

The AAF has been acknowledged by NP to have been working appropriately historically. In 2007, the AAF produced a Return on Equity of 8.6% [Jocelyn Perry, Oct 19, 2009, p. 116, line 23]. In 2010 the AAF's continued use is forecast to result in a forecast 2010 return on equity for ratemaking purposes of 8.39%. [Amended Application, p. 3-19, line 16]

Having regard to the fact that NP is low risk, having transferred nearly every conceivable risk to its customers, there is no basis to say that the AAF needs to be abandoned when it would provide an 8.4% ROE for ratemaking purposes, some 65 basis points higher than Dr. Booth's fair return recommendation.

We now have had a close enough look at US utilities in this case to be confident that there is no reason to depart from the AAF in this province on the basis of the higher allowed ROEs in the US. That heresy has now been scotched.

Treatment of Other Post-Employment Benefits

In this General Rate Application Newfoundland Power proposes to adopt the accrual method of accounting for other post-employment benefit costs effective January 1st, 2010. This imposes upon the ratepayer a very significant increase in costs. The increase in revenue requirement for the year 2010 caused by the annual accrual of other post-employment benefits is 6.7 million dollars. (Revised Application - Vol I, Table 3-17)

Notwithstanding that Newfoundland Power is proposing to commence accrual accounting of OPEBs in the 2010 test year, Newfoundland Power is proposing that the disposition of the legacy transitional obligation (the accumulated, non-accrued obligation from prior years) be addressed at a future GRA proceeding in 2010 or later. This amounts to 46.2 million dollars and, depending upon its amortization, will have an impact almost as large as the annual accrual upon the revenue required from rate payers. (See Volume 1, Revised Application, page 3-30)

In her evidence Ms. Jocelyn Perry, Vice-President of Finance for Newfoundland Power, stated "For something of the magnitude of 46 million we have indicated that between five or ten years appeared to be reasonable" as a period of amortization. (Transcript of Evidence, October 19th, 2009 at Page 146, Lines 15-17)

It is not unreasonable to expect that the future impact upon rate payers by virtue of the annual accrual of OPEBs and the amortization of the transitional cost would be an increased revenue requirement of greater than 11 million dollars. The current proposal and annual accrual of OPEBs, amounts to fully 25% of the increased revenue requirements proposed by this application. (See Volume 1, General Rate Application, Exhibit 7, Page 1) Even according to the President of Newfoundland Power, Mr. Ludlow, the accrual of OPEBs accounts for 1.3% within a total rate increase of 7.2%. (See Exhibit EAL, No. 1)

The Newfoundland Power proposal asks the rate payer to bear a very large burden for future years. This large burden does not provide any significant present benefit. Certainly, the increase in customer rates reflecting the accounting change will have no operational benefits for customers. And the additional cash is not required to fund an OPEBs Plan, nor will it be segregated, comparable to a pension plan, to provide the funds to meet future OPEBs obligations.

Moreover, the annual expense to be accrued on account of OPEBs is not a stable amount. Rather, it is quite volatile. The annual expense proposed for OPEBs has changed by 1.2 million dollars just over the course of the current application. The original application proposed a revenue requirement increase on account of the move to accrual of 5.6 million dollars. By the revision filed September 28th, 2009 this amount had increased to 6.8 million dollars (See Tab 4, Table 8, Page 13, Original Application and Amended Application filed September 28th, 2009). The Grant Thornton Report also refers to the risk of variability in OPEBs expense at page 7.

There are significant variables which change the value of OPEBs from time to time, both as relates to annual accrual costs and transitional costs. (See Evidence of Jocelyn Perry, October 19th, 2009, Page39, Line 12 - Page 40, Line 17) These variables are listed in Volume 2 at Tab 5, Page 11 and include change in demographics, change in claims costs, change in aging, change in medical trend, change in discount rate, change in mortality assumption, and actual benefit payments differing from expected.

This amount will not be stable year to year. It is anticipated that the annual OPEB expense will be adjusted annually on the basis of a best estimate by the company's actuaries. (See Evidence of Jocelyn Perry, October 19th, 2009, Page 57, Lines 13-14) The increase in the cost of OPEBs between the original application and the Amended General Rate Application was a function of a change in the discount rate. However it is not only the discount rate that can change the annual accrual to be expensed on account of OPEBs. Just one of the factors, the medical trend, has changed as much as 18 million dollars year over year. The change in one factor may be balanced out by countervailing changes in other factors or it may exacerbate the expenses in the extreme. There is no real linkage between the factors. (See Volume 2, Tab 5, Page 11; Evidence of Jocelyn Perry, October 19th, 2009, Page 59, Lines 14-15)

Over and above the estimates provided annually, an actuarial study will have to be done periodically which, in itself, will result in the truing up over time of the amount of the annual accrual and transitional expense. This trueing up will be recognized as an expense over a period of time, possibly 15 years. (See Evidence of Jocelyn Perry, October 19th, 2009, Page 62, Line 8 - Page 63, Line 19)

As a consequence of this estimating process, the process of accrual does not eliminate but only reduces inter-generational inequity. What is being expensed annually is only an estimate. Any changes will be visited upon the rate payers of future years. (See Evidence of Jocelyn Perry, October 19th, 2009, Page 64, Line 3 - Page 65, Line 4)

The perpetuation of inter-generational inequity is far more evident when it comes to the transitional obligation expense. The transitional obligation expense does not eliminate any inter-generational inequity; it is just another visiting on tomorrow's ratepayers of yesterday's costs. This, of course, is exactly what the current cash system of expensing OPEBs when they are incurred does. (See Evidence of Jocelyn Perry, Oct 19, p 65, Lines 6-22)

Newfoundland Power takes the view that the volatility of OPEBs is less significant because its expense size is about 1/3 of the size of the pension obligation expense. (See Evidence of Jocelyn Perry, Oct 19, p. 44, Lines 6-19) As was noted above, the variation in the annual OPEB expense, without regard to the transitional expense, varied by 1.2 million dollars because of a change in the discount rate within a period of 5-6 months. We would direct the Board's attention to Grant Thornton's Report, p. 7, lines 28-44 and page 8, lines 6 to 7.

When one takes into consideration the transitional expense, the total annual revenue requirement imposed upon the rate payer is indeed very significant. It is reasonable to anticipate such expense as being in the range of 11 million dollars. What the actual amount will be is highly dependent upon the period of amortization, if indeed that is the approach taken when dealing with the transitional expense. While it is true that the majority of utilities in Canada use the accrual method of accounting for OPEBs, most introduced it a number of years ago when their transitional expense was not high. (See CA-NP-202, 2008 GRA verified in the evidence of Jocelyn Perry, October 19, p. 22, Lines 5-14)

Other post-employment benefits should not be dealt with on the basis of the annual expense alone and in isolation from the combined rate impact of annual accrual and transitional costs. The Board ought to have before it a proper analysis of the entire OPEBs question. There is a need to consider mechanisms to smooth the rate impact of these two significant new rate expenses. (See NP-CA-56, Evidence of John Todd, October 27th, 2009, Page 86, Line 2 - Page 88, Line 8)

The Cost of OPEBs

Leaving aside the discount rate, the cost of OPEBs is a manifestation of the increase in cost of group benefits for all Newfoundland Power employees. The factors causing rapid escalation in costs for group benefits include utilization and the cost of prescription drugs. (See Evidence of Jocelyn Perry, October 19th, 2009, Page 25, Lines 8-11)

As a consequence of these burgeoning costs, Newfoundland Power is entering upon a review of its group plans with the union representing two bargaining units of its employees, with a view to changing its costs picture. The outcome of this process is unknown as yet. (See Evidence of Jocelyn Perry, October 19th, 2009, Page 101, Line 25 - Page 103, Line 9) Newfoundland Power stated that this review is to conclude by the end of 2010, thereby effectively excluding the actual results of the review from consideration in the 2010 test year.

Newfoundland Power has had recommendations for cost reduction in its group benefits and, in particular, with respect to its retiree group benefits since the year 2005. (See Attachment A to CA-NP-293) This report from the company's consultants, AON, makes a series of recommendations with respect to reducing the costs of retiree benefits under Newfoundland Power's group plan. These recommended changes include, but are not limited to, having retirees bear a larger part of the burden of the cost of retiree benefits. Notwithstanding numerous recommended changes, Newfoundland Power has adopted one change only. This change is the setting of a requirement of ten years of service and age 55 in order to receive the benefit. It has made no others amongst the recommended changes in over four years. (See Evidence of Jocelyn Perry, October 19th, 2009, Page 92, Lines 1-21)

Changing the cost of OPEBs is not a difficult matter to achieve nor is it an extreme measure. No provision exists in the Newfoundland Power Collective Agreements with respect to post-employment group benefits. (Oct 19, p. 66, Lines 6-12) Retirees are given notice by means of a benefit booklet that benefits terminate with the expiry or termination of the group insurance contract. There is no written document whereby a promise or contract is made to Newfoundland Power employees that free group benefits will continue to be available to them after age 65. (Oct 19, p.66, Lines 23 - p. 77, Line 19)

A change in the cost of group OPEBs would hardly move NP into the category of a miserly employer. The AON Report indicates that 58% of employers surveyed provide no group benefits for retirees. The group surveyed is not radically different from the group used by NP for comparison for wage purposes. (See Attachment A to CA-NP-341, Page 43, Question 24, Page 7) Moreover, the AON survey evidences the fact that the minority of companies that offer retiree benefits, in large part, have either already made or plan to make changes to future retirees' coverage. (See p. 43, Question 25)

CA-NP-345 indicates that retirees from the Government of NL and from Hydro over the age of 65 pay half of the premium cost of benefits which they receive in common to employees of NP; that is, excepting dental. NP retirees receive generous benefits. NP provides contributions to pension benefits over and above employer contributions to CPP in the amount of 5% of income to the defined benefit or the defined contribution pension plans and 1.5% on behalf of the 98% of employees who participate in the voluntary RRSP. (Oct 19, p. 76, Line 8 - Page 77, Line 1) NP retirees experience reduction in premium costs for group benefits upon retirement because of the elimination of disability insurance. (Oct19, p. 31, Lines 13-25)

It would appear that the overall trend of retirement at Newfoundland Power is that employees retire well before the age of 65. The company has offered a number of early retirement programs and the pattern is such that as of December 31st, 2008 there were only 15 employees greater than age 60 but there were 235 retirees less than age 65. (See Volume 2, Tab 5, Pages 14-15) A prospective change in entitlement would not hit a disadvantaged group and would provide ample notice to allow retirees to adjust.

The reply to CA-NP-345, with respect, paints a distorted picture of the ability of NP's retirees to contribute to the costs of group benefits by suggesting that the average Newfoundland Power retiree age greater than 65 receives something less than $14,000.00 per annum as a pension from Newfoundland Power. They exclude from this figure CPP and the income from the voluntary RRSP. In comparing retirement benefits for retirees of the Newfoundland & Labrador Government and Newfoundland & Labrador Hydro, they ignore the higher contribution rates of these retirees and use dental costs for a group of all employees and dependents and retirees and dependents under the age of 65, as the means to calculate the value of dental coverage received by Newfoundland & Labrador Hydro retirees. It is unlikely that the utilization rate for retirees over the age of 65 would be as high as the general group considering the likely total lack of dependents. What they appear to forget is that they are asking many rate payers with no pensions or OPEBs to pay for these benefits.

The financial impact of changes to retiree group entitlements are very significant. A change which means that employees retiring after January 1st, 2010 will have to pay one half the cost of group benefits when they reach 65 years of age would reduce the annual OPEB accrual by 2.5 million dollars each and every year. (The change would also reduce the projected accrued benefit obligation by over $10,000,000.) (See Evidence of Jocelyn Perry, October 19th, 2009, Page 98, Lines 4-13; and see CA-NP-337 - 2nd Revision) A similar reduction would occur if the change were made effective January 1st, 2011. It should be clearly understood that the retirees who would be affected by this proposal are not those current retirees referred to in CA-NP-345. These are retirees who, in all likelihood, will be a number of years under age 65 who will have a number of years to adjust to the change.

Newfoundland Power is proceeding with a review of its group benefits to be completed by the end of 2010. A change as benign as that suggested in the preceding paragraph will create a significant reduction in expenses from the test year which will go straight to Newfoundland Power's bottom line. This reduction in expenses could foreseeably allow Newfoundland Power to earn to the top of its range of allowed rate of return on rate base in 2011. Test year costs should not include expenses that are anticipated to change. (See Evidence of John Todd, October 27th, 2009, Page 84, Line 23 - Page 85, Line 17)

The evidence suggests that the OPEBs expense does not need to be as high as that asserted by Newfoundland Power. Rather, it is reasonable to anticipate that Newfoundland Power can implement some of those changes recommended to it in 2005 to bring this expense down by a significant amount.

Summary

In the circumstances outlined above, it would be reasonable and prudent for the Board to:

(i) defer accrual accounting of OPEBs until Newfoundland Power has made a reasonable effort to reduce the cost of OPEB expenses; and

(ii) defer accrual accounting of OPEBs until the Board has had the opportunity to deliberate on the full impact upon rates of the accrual accounting of annual OPEB expense and transitional costs and to consider any mechanisms to smooth the impact of this volatile expense.

Inter Corporate Transactions

The Consumer Advocate takes issue with the fact that NP personnel have been carrying out storm/hurricane repair/reconstruction work for Fortis affiliates in the Carribean areas at cost. The Consumer Advocate also takes issue with NP's practice of permitting secondments of its staff at cost to affiliates. The Consumer Advocate has previously taken issue with the 20% mark-up applied to Executives and Managers and anticipates that this issue will be addressed in the ongoing process to establish an Inter-Affiliate Code for NP as ordered in PU 32 (2007).

In its Decision and Order No PU 32 (2007) the Board noted the Consumer Advocate's Written Submission as follows:

> *"Transactions between the utility and its affiliates present unique challenges, as they are non-arms length transactions. Economically, it must be observed, there is no real incentive for NP to seek to maximize benefits to the advantage of its ratepayers. If NP charges more for the service it provides to its parent or affiliates, it will reduce the profits of its shareholders."* (emphasis added)

CA-NP-273 shows that 3979.75 hours were expended at cost by 14 Powerline Technicians in support of Fortis Turks and Caicos in 2008. NP personnel also played a key coordinator role in the Fortis Turks and Caicos effort. (CA-NP-272) Prior to Fortis establishing Fortis Turks and Caicos, NP did not provide assistance to the utility provider on Turks and Caicos. (CA-NP-274) NP does not know to what extent other utilities provided assistance to the utility in Turks and Caicos before Fortis Turks and Caicos was established and does not know whether external utilities have continued to assist since the establishment of Fortis Turks and Caicos. (CA-NP-275)

CA-NP-269 shows that in 2004 NP personnel provided 16,984 hours at cost to assist the Fortis-owned Carribean Utilities Company in respect of Hurricane Ivan. This work was carried out in Grand Cayman, an international banking locale. Prior to that, NP personnel spent 2292 hours at cost to assist Belize Electricity with Hurricane Keith.

CA-NP-269 demonstrates that the only occasions over the past 15 years on which NP has provided assistance to other utilities outside the province has been to Fortis affiliates in Belize, Grand Cayman and Turks and Caicos. CA-NP-269 also demonstrates that over the past 15 years, the only utility that has provided assistance to NP has been NLH and *vice versa*.

The Consumer Advocate does not view NP's assistance as part of the "Fortis Energy Response Network" described in Fortis' Annual Report for 2008 (at p. 16) (CA-NP-58) as being analogous for regulatory purposes of a situation where NP is called upon to provide assistance in Nova Scotia, Quebec or even a US state to a non-affiliate on an occasional basis. Rather, what we have in the case of the Fortis Energy Responses Network is an established team to remove or at least ameliorate an ongoing business risk of carrying on a utility business in the Carribean. In fact at p. 25 of its 2008 Annual Report, Fortis notes that the higher regulated return in the Carribean is "*correlated with increased operating risks associated with local economic and political factors and weather conditions.*" Fortis goes on to state that, "*The Corporation's operations in the Carribean are exposed to hurricane risk. Fortis used external insurance to help mitigate the impact on its operations of potential damage and related business interruption associated with hurricanes.*" Can there be any doubt that Fortis also relies upon NP personnel to help mitigate its risks in the Carribean regardless that Mr. Gary Smith largely refused to acknowledge it and Mr. Earl Ludlow appeared to see the deployments as merely humanitarian missions to a stricken country.

Not only have shareholders of Fortis benefitted by having generous access to NP's highly trained and competent workforce at cost, but the ratepayers of these localities are being shielded from the full and proper cost of the restoration efforts. It would appear from p.

34 of the 2008 Annual Report that there is a hurricane cost recovery surcharge or "CRS" at Carribean Utilities. Logically, that CRS is not as high as it would otherwise be if market rates applied to NP personnel. In effect, NP's rate payers are subsidizing customers in the Carribean whilst providing shareholders of Fortis Inc. an unearned benefit.

It is ironic that NP's rate payers paid market rates when NP used contractors to assist with restoration and reconstruction efforts on the Bonavista Peninsula, but NP's ratepayers are expected to not complain when Fortis has effectively institutionalized a cost-based regime when one of its Carribean interests requires assistance. Unquestionably, an equity investor in Fortis would view the opportunity to use regulated personnel at cost to mitigate a known business risk in the Carribean as a real benefit.

CA-NP-151 demonstrates that when NP provides technical services under contract with Aliant Telecom Inc., it charges a market rate which equates with 1.45 times the fully distributed cost. At CA-NP-149 - Attachment "A" - NP provides a break down of Inter-Corporate charges to Affiliates from 2002 to 2010 (f). The Staff Charges line is meant to encapsulate labour and travel expenses relating to work performed by NP employees for any of its affiliates. Footnote 3 indicates that the increase in 2008 to 1,057,284 (from $894,468 in 2007) was primarily related to the hurricane relief effort in Turks and Caicos.

The key point is that none of the historical annual amounts reflects a mark-up being charged for such services so these figures in CA-NP-149 are an under-statement of what the costs should have been. CA-NP-276 confirms that the forecasts of staff charges for 2009 <u>and 2010</u> are based on three year rolling averages of historical costs. Mr. Smith testified (Oct 26, p. 109) that in arriving at the amount for rechargeable and recoverable labour in the test year labour forecast, he believed that NP did a trending of historical costs. Inasmuch as these prior years did not reflect a market rate charge, the staff charge forecast of $980,723 (CA-NP-149) and the rechargeable and recoverable labour of $4,445,000

(Schedule B 2010 Internal Labour Forecast) are understated, hence overstating the 2010 Revenue Requirement.

In addition to not receiving the benefit of a market rate for NP personnel, the testimony of Mr. Gary Smith raised significant concerns about the effect of such deployments on operations here in Newfoundland. As explained by Mr. Smith (Oct 26, p. 134) NP would have to turn around and back fill with contract labour (at market rates) and his *"point of being comfortable is to make sure that labour is no more expensive than our own labour, and that way our customers wouldn't be negatively impacted."* Whilst noting that NP did not tender any evidence to establish that contract labour was "no more expensive" than the labour being supplied to the Carribean at cost, the significant concern that remains is the fact that the replacement of skilled line technicians with contract labour is not an "even swap" from an operational point of view. Mr. Smith spoke of the recent situation with the deployment to the Turks and Caicos at p. 138:

> *"Mr. Smith:*
>
> *A. Again my response to that in terms of my own personal ability to respond with my own knowledge would again go back to the Turks and Caicos incident. The contract labour that we brought in to supplement their own workforce while these individuals were away is very limited in what they can do. Basically, this contract labour goes into subdivisions and is able to run the wires between the poles and hang the insulators. It's a very basic form of our line constructions. So this contract labour when you bring it in, if you have that type of work in the chit to be done in the future then that contract labour can come in and do it for you. Of course, our own employees would have done that work, but, of course, our own employees also had to do a much broader perspective of work in general. So at any particular point in time, yes, they would do the subdivision work that the contractor could do, but certainly in the run of a year they had to do a lot more work than just that."*
> (emphasis added)

As regards secondments, CA-NP-150 only asked NP to provide details as to NP personnel over the past 3 years that have been seconded to an affiliate. The reply confirms that secondments have continued to take place. Notably, besides a secondment of an

Engineering Technologist, the Director of Financial Reporting and Treasury, the company Treasurer and the Director of Environment have all been seconded. The secondments continue to be uni-directional as CA-NP-277 states that no personnel of other Fortis Inc. companies have been seconded to NP from 2007 to present. CA-NP-279 provides the position descriptions of the 3 senior positions involved in the secondment. Clearly, these are important and responsible positions. Ms. Perry admitted that these individuals were charged out at fully distributed cost. (Oct 19, p. 3)

In reply to CA-NP-278, NP stated that *"For NP, the principal benefit of a secondment arises for the career development opportunity it provides for the seconded employee. Secondments expose employees to new work situations and, often to different challenges than their regular jobs. Seconded employees return to their regular employment with new skills, knowledge and experience, which ultimately benefits both Newfoundland Power and the individual employee."* (underlining added)

The fact of the matter is that the Treasurer who was seconded from December 2007 to June 2009 did not return to NP (Mr. Ludlow - Oct 15, p. 10, line 23). In fact even the person (Jamie Roberts) who took over the Treasurer duties (while the Treasurer was on secondment to Fortis Inc.) left NP to become CFO with Fortis Properties (Oct 15, p. 10, lines 3-4). The secondment experience, one observes, has benefitted the individuals involved and Fortis Inc. but not so much NP.

Admittedly, the Director of Environment returned to NP at the end of his secondment (and assumed a non-environment role), but he was obviously asked to go to Fortis Alberta to assist Fortis Alberta with a need they had. No one would argue that the Director of Environment may have grown from the experience, but the fact remains that Fortis Alberta got valued expertise at cost and this individual would have grown just as well at market rates. Given the repeated and consistent lack of reciprocity in these staff transfers, there is no basis to continue charging at cost for such valuable employees. Attachment B of CA-NP-149 shows Regulated Inter-Corporate Staff Charges from Affiliates to be as follows from 2007 to 2010 F:

2007	2008	2009	2010 F
–	–	–	–

If this is not a graphic indication of the "one-way" nature of Fortis secondment and staff deployment policy, what is? Why a net seller of valuable professional and staff services would continue to refuse to charge more than cost for the services can only be understood by realizing that NP has no financial incentive to charge an appropriate amount as doing so will lessen the return of Fortis shareholders. This is why a regulatory direction is needed and why these inter-corporate relationships pose "unique challenges".

The Board has already stated that benefits with regard to the provision of staff and other services to NP's affiliates should "be transparent, demonstrable and maximized to the advantage of ratepayers". [PU 19 (2003), p. 57]

It would appear to the Consumer Advocate that the least NP should be expecting to be paid for the use of its personnel for non-utility services is the person's Fully Distributed Cost. That just ensures that ratepayers are not being disadvantaged by the transaction. That is the least one should expect. But this Board has stated in P.U. 19 (2003) at p. 57:

> *"With regard to the provision of staff and other services to its affiliates the Board agrees NP may indeed be deriving benefit on behalf of ratepayers. The Board believes, however, such benefits should be transparent, demonstrable and maximized to the advantage of ratepayers."* (emphasis added)

This Board effectively decided that it was not enough for NP to show that a transaction did not disadvantage the interests of ratepayers. NP had the onus to show that ratepayers and the utility will derive some demonstrable benefit from such transactions. While it is arguable that a staff person who assists an affiliate may pick up some beneficial experience in the process, that should not be a justification for failing to charge a market rate or at least a reasonable proxy rate for the staff persons' services. Is this intangible of "work experience" a "demonstrable benefit" within the meaning of P.U. 19 (2003)? Indeed, if "work experience" constitutes a sufficiently "demonstrable benefit" within the meaning of P.U. 19 (2003), why did the Board feel compelled to introduce the mark up on executive and management time in the first place? The same logic applies to staff charges. A party in an arms-length transaction would not fail to charge an appropriate mark-up on the grounds that the person being hired out was being exposed to a valuable learning experience. An arms-length party would be seeking to maximize its benefits from the transaction and that is what P.U. 19 (2003) sets forth in its reasons and that is what consumers expect. Accordingly, it is the Consumer Advocate's submission that staff charges should be adjusted to charge fair market value or an appropriate mark-up. The use of Fully Distributed Cost has no place where consumers have the right to maximum benefits. This would be in keeping with the principles enunciated by the Board in P.U. 19 (2003).

Executive Compensation

Mr. Ludlow's base salary has increased by 6.3% in 2008 and 10.4% in 2009. In 2007, the base was $315,000. By 2008 it was $335,000 and on January 1, 2009 it was $370,000 (CA-NP-246).

These rates of increase are nothing short of astounding, given the economic environment and the fact that Newfoundland Power is a low risk, stable provider of electricity and electricity distribution services. The apparent justification asserted by Newfoundland Power for these increases is its need to place executive compensation at the median level indicated by a sample of executive compensation prepared by the Hay Group in order to compete for executive talent. This sample identifies an index of 292 commercial and industrial organizations as the appropriate comparator group. (See Volume 2, Tab 11, Compensation Review Page 4). This sample includes a diverse group of privately owned businesses, many of whom appear to be a great deal larger than Newfoundland Power in terms of book value, sales and numbers of employees. Likewise, it can be inferred that a number of the companies are somewhat smaller than Newfoundland Power. The exact position of Newfoundland Power within the comparator group, on any measure, is difficult to assess. (See Volume 2, Tab 11, Appendix C, Pages 11-13.)

The justification for Newfoundland Power's position is presented by Mr. Karl Aboud of the Hay Group. With the greatest respect to Mr. Aboud, it is submitted that the Commissioners should regard his evidence with a degree of skepticism. When asked:

> *"Could you tell us what tests you have done to determine the extent to which Newfoundland Power has over the past 10 years actually competed with organizations across the breadth and depth of business sectors across Canada for executive talent?"*

Mr. Aboud answered:

> *"We haven't looked at the organizations from which and to which the five executives were recruited or past versions of executives have left to. So, the fact that by coincident your executives, I think I am going out on a bit of lack of knowledge basis, your executives are more transferable from the Fortis operating businesses than they are from other organizations outside Fortis. So your reflective market has been Fortis operating by the coincidence of the executives that currently are in place in those jobs is coincidence, you could have just as easily, I suspect, in all my other organizations, they could just as easily have lost or gained senior executives from businesses of any sector. By coincidence, I don't think your current inventory of executives have recently come or gone to other sectors, but they have come and gone from within the Fortis family."* (See Oct 26, p. 69, Line 17 to p. 70, Line 20)

The answer is evasive and by no means addresses the question. The Board is referred as well to an exchange of questions with Mr. Aboud where he was asked:

> *"Q. Now you indicated that you can slice and dice your data to come up with just about any kind of example that our client would want, correct?"*
>
> *A. Correct.*
>
> *Q. So for instance, for a data base for comparison, you could create a data base, a subbase, out of your 532 for companies having sales less than a billion dollars?*
>
> *A. Correct. Yes.*
>
> *Q. Or companies having a book value less than 2 billion dollars?*
>
> *A. Sure.*
>
> *Q. And you could create an Atlantic utility data base, right?*
>
> *A. In theory, as long as there is enough observations to support it, yes.*
>
> *Q. And likewise a Canadian utilities data base?*

A. *Yes.*

Q. *Or an Atlantic Canada regional data base?*

A. *Yes, that's true.*

(See Evidence of Karl Aboud, October 26, 2009, Page 48, Line 11 to Page 49, Line 16.)

Subsequently Mr. Aboud was asked:

"*Q.* *. . . Mr. Aboud, where would Newfoundland Power fit in your example in terms of book value of the company?*

A. *Sorry, I don't know.*

Q. *But you can find out.*

A. *I can certainly find out your book value, but the relative positioning of book value to the book value of broad orgs, we don't collect book value as a statistical metric in our organization, so I couldn't tell you where it sits relative to.*

....

Q. *Can you tell us where Newfoundland Power would sit amongst your sample in terms of sales/revenue.*

A. *So your revenue is in the area of between five and six hundred million dollars.*

Q. *Very close to five.*

A. *Very close to five. We have revenue of organizations of Appendix C that would be from 100 million much smaller to many billion much larger. Where it sits relative to the rank order of broad orgs, honestly I don't know."*

(See Evidence of Karl Aboud, October 26, 2009, Page 56, Line 25 to Page 58, Line 16.)

It is apparent that Mr. Aboud asserted his sample could be organized for companies both in terms of book value and sales/revenue. But when asked the position of Newfoundland Power within the sample on that basis, he declined to do so.

When asked by the Chairman if the regulator and ratepayers were concerned with 25 percent compensation, Mr. Aboud left a false impression with the Board. (Evidence, October 25, Page 66, Lines 4-19). He asserted that if one backed out, the LTI (always a shareholder paid benefit) that Mr. Ludlow's compensation would be "650 ish thousand" which is very similar to the P25 value of the market. What he did not point out is that the 650ish thousand at the P25 level of the market includes shareholder paid long term incentive in the amount of $95,000.00. The value of the twenty-fifth percentile for comparison purposes is $555,500.00 (See Volume 2, Tab 11, Page 7). The Commissioners should carefully scrutinize anything Mr. Aboud has said.

The fundamental position of Hay Group as to the justification of Newfoundland Power's executive compensation policy is that Newfoundland Power competes for its executive resources with organizations across the breadth and depth of business sectors across Canada. (See Volume 2, Tab 11, Page 4).

This position says that Newfoundland Power is required to be competitive with the organizations represented by the HAY group sample. Further, Newfoundland Power positions itself at the median of the sample because "as a utility it is appropriate to compare to an average of a broad marketplace as opposed to only the higher paying sector e.g. gold mine" or only the lower paying sectors e.g. retail." (See Volume 2, Tab 11, Page 5)

The expense of executive compensation like any other expense in the test year must be justified by the Applicant. It is submitted that no justification for executive compensation increases has been brought forward by Newfoundland Power. Newfoundland Power claims that it is necessary to compete with a broad group of organizations in the private marketplace across Canada. The evidence, for instance, indicates that Mr. Phonse Delaney and Mr. Gary Smith essentially swapped positions as Vice President of Operations and Engineering at Fortis Alberta Inc. and Newfoundland Power. (Reference: Evidence of Earl Ludlow, October 15, 2009, Page 128, Line 22 - Page 129, Line 25.)

The evidence further indicates that Mr. Ludlow and his precedessor, Mr. Karl Smith, came to Newfoundland Power from Fortis Inc., that Gary Smith and Phonse Delaney came to Newfoundland Power from other Fortis companies and that generally Newfoundland Power executives come from Newfoundland Power or other Fortis Inc. companies. (See Evidence of Earl Ludlow, October 15, 2009, Pages 2, Line 13 to Page 5, Line 21.)

As indicated above, Mr. Aboud, Hay Group's representative, did not respond when asked whether Hay Group had done any tests to determine the extent which Newfoundland Power has over the past 10 years actually competed with organizations across the breadth and depth of business sectors in Canada for executive talent. The Board of Commissioners can only conclude Newfoundland Power did not. It is submitted that the employment history of Gary Smith is a classic example of the manner of recruitment of executives with Newfoundland Power. Mr. Smith started with Newfoundland Power in 1984 in its distribution group, progressed through that company and ultimately moved with two other Fortis companies in progressively important positions before returning to Newfoundland Power as Vice President of Operations and Engineering. (See Evidence of Gary Smith, October 26, 2009, Page 105, Line 19 to Page 106, Line 13.)

Given that Newfoundland Power recruits from within, it is submitted that it is appropriate to look at Newfoundland Power's compensation policy for non-executive managerial employees. In the answer to CA-NP-339 of the 2008 Newfoundland Power GRA (Information No. 7), Newfoundland Power confirmed:

> *"Newfoundland Power uses the services of Hay Group, a management consultancy to conduct its salary and total cash compensation review for managerial employees. The company aims to be competitive with Atlantic Canadian utility companies.*
>
> *Due to the low number of participants within Atlantic Canada, Hay Group recommends a larger comparative group, i.e. all Canadian utilities for the review recognizing the pay differentials for Atlantic Canada is comparable to the 25th percentile of the national market."*

If there is no evidence to demonstrate a pattern of competition with organizations across the breadth and depth of business sectors across Canada for executive talent and there is evidence that the group from which its executives are selected, the non-executive management group, is compensated on a substantially different basis, it is reasonable for the Commissioners to conclude that Newfoundland Power's compensation for executives is not reasonable or prudent. There is no evidence of retention difficulties within Newfoundland Power at the executive level. Indeed, there seems to be very little in the way of loss of employees overall and none within the management group. (See CA-NP 242)

Positioning the executive of Newfoundland Power at the median of a reference sample is similarly unjustified. There is no evidence as to where Newfoundland Power sits within such a sample on the comparative measures of book value and revenue. All that Mr. Aboud says is that you don't want to be high and you don't want to be low. Surely something more substantial is required to justify positioning Newfoundland Power executive in the middle of a salary range paid by companies about which we know and have been told very little.

In the absence of evidence to support its executive compensation policy, the Commissioners should not allow as a regulated expense the salary increases based in that policy. Shareholders in Newfoundland Power may wish to continue to reward its executive in accordance with the executive compensation policy. However, before rate payers can be expected to bear that burden, there is a burden on Newfoundland Power to show that such expenses are justified as reasonable and prudent expenses in the operation of the utility. Newfoundland Power has failed to do this.

<u>Whether Operational Cost Reductions and Efficiencies Should be Considered</u>

As outlined in the part of this submission pertaining to Inter-Corporate Transactions, the Company has overstated its Revenue Requirement by not incorporating market based rates in its Staff Charges to Affiliates. Certainly, this is a cost reduction opportunity that must be considered for forecast 2010.

As established in cross-examination of Gary Smith (Oct 27, 2009) NP's forecast expenses for 2008 as filed in October of 2007 came in $736,000 lower based on the actuals for 2008. One of the larger variances from forecast arises due to an over-estimation of the test year Uncollectible Bills expense. In October of 2007, NP had forecast $1,050,000 but the actual expense was $836,000 producing a $216,000 variance.

NP is forecasting an Uncollectible Bills expense for both 2009 and 2010 of $963,000, which is approximately 15% higher than the 2008 actual expense.

On cross-examination, Mr. Smith was asked why NP would assume that uncollectibles would increase by 15% over 2008. Mr. Smith answered (at p. 15, Oct 27, 2009) as follows:

"Mr. Smith:

A. The way the uncollectible bill number is calculated for 2009, and then the number was held consistent for 2010, was on a three-year average. So it would look at 2006's actual, 2007 and 2008. I believe that's typically how we've looked at this number. We use an historical average to forecast it.

Mr. Johnson:

Q. *Okay, but that doesn't give weight to the most recently confirmed number to the extent that I guess I'm suggesting it should, because the 2008 number gets lost within the other previous years, which were* considerably higher.

Mr. Smith:

A. *Yeah, we look at this line and we believe the most appropriate way to forecast is with a three-year average, as opposed to the most current actual."*

The Consumer Advocate recognizes that forecasting Uncollectible Bills is an inexact science but in light of the variance the company's methodology has produced and given the relative lack of weight given to the most recent actual numbers that we have (ie 2008), an adjustment should be made to this operating cost item.

The Consumer Advocate would also question the reasonableness of NP's labour forecast assumption that its retiring employees in 2010 will all retire at year end. This issue was discussed with Mr. Smith on October 26 from pages 166 to 171.

The Consumer Advocate also would question, based upon the above examination of Mr. Smith, whether NP is in fact being too conservative in putting forward its estimates of the number of retirees from NP in 2010. CA-NP-114 establishes that NP has been experiencing more actual retirements than forecast - as the forecast is based on the assumption that an employee will only retire upon reaching age 65, or age 60 with the combination of years of age and service of 95 years.

The Consumer Advocate would also question the appropriateness of NP including forecast costs in 2010 related to a 2010 GRA in the test year. (See Undertaking No. 8 filed October 27, 2009 and cross-examination of Gary Smith of October 26, 2009, p. 178-183)

Proposed One Year Amortization of Board and Consumer Advocate Costs Related to this Application

At para. 11(b) of its Amended Application NP proposes that the Board approve amortizations with effect from January 1, 2010, to

> "(b) *recover over one year an estimated 750,000 in Board and Consumer Advocate costs in relation to the Application;*
>
> *as set out in the evidence filed in support of the Application and this Amended Application."*

The Consumer Advocate opposes this proposal and instead would propose that the costs be amortized over a 3 year period consistent with the last GRA order of 2007. It bears noting that the forecast 2008 regulatory costs are being amortized over 3 years and in fact will not be fully amortized until 2010 - meaning that one-third of the forecast cost for 2008 will already be included in 2010 rates. If 2010 GRA costs are also included in the 2010 rates fully, there will essentially be 133% of GRA costs included in 2010 rates - part of the cost from 2008 and 100% of the forecast cost for 2010. If NP ends up not filing a GRA for 2011, the rates in 2011 and going forward will implicitly include the same 133 percent of the cost of a single GRA, as well as any subsequent years until there is another GRA. This recovery will correspond to costs that were not actually incurred. On the other hand if there is another GRA in 2011, the 2008 cost would no longer be in rates and there would be one-third of the 2010 GRA costs plus one-third of the cost in 2011, which would be basically two-thirds of a normal GRA's costs in rates.

If the 3 year approach is adopted, the recovery of GRA costs will be smoothed and the cost of the burden on rate payers will never exceed three-thirds of typical GRA costs.

The Consumer Advocate acknowledges that the foregoing paragraphs generously draws from Mr. John Todd's direct evidence at pp. 78-80 of his October 27, 2009 direct testimony, to which the Board's attention is further drawn for a better exposition of this issue.

Kenmount Road Property

This issue came to the attention of the Consumer Advocate upon reading p. 3-4 of the Finance Evidence filed by NP on May 28, 2009. NP produced Table 3-2 which showed Other Revenue: 2007 to 2010 E. One of the categories of Other Revenue was "Miscellaneous". Footnote 11 explained that for 2009 F, Miscellaneous revenue *"includes a 384,000 gain on the sale of property."*

In 2009, NP sold a parcel of vacant land on Kenmount Road to an adjacent land owner for $618,000. A survey description of the 3.334 hectare parcel that was sold is found at CA-NP-184, Attachment A.

NP has stated in CA-NP-281 that the vacant land had a total book value of $234,000 and was acquired as five separate parcels with acquisitions occurring in 1961, 1965, 1973, 1986 and 1989. According to CA-NP-184, *"The property was part of the land assembled for the Company's head office facilities."*

It is assumed that it is common ground that NP constructed its Kenmount Road head office in 1968 as a two story structure consisting of a ground and first floor. In 1979 two more floors were added. [These facts are reported in reply to CA-NP-43 of the NP 2010 CBA - Attachment A, p. 2]

Nothing physically had been done with the vacant land that was sold in 2009. At p. 6 (Oct 19, 2009) Ms. Perry stated:

> "A. *This particular property just has trees on it. The piece going up between the two buildings, I'd refer to it as a ditch. It looks no more than a property line, and up back, it's just a wooded area."*

The property in question was zoned as Rural (p. 38, October 15, 2009).

Mr. Ludlow testified (p. 33 - Oct 15, 2009) that the land was pulled together on the premise

> *"that it would - parts of the land would form a portion of almost like a centralized depot/head office for Newfoundland Power. Now that's my recollection and understanding. I can't go back to '61, but I can go up to the 80s and from there decisions were subsequently made to construct Duff (sic) Place within the Industrial Park, and a Control Centre on Topsail Road, and to leave Kenmount Road as the building that it is today, which is the administrative head office. That's my understanding of how the land was pulled together."*

The record will reflect that Duffy Place was built in 1990, a year after the last acquisition was made on Kenmount Road in 1989 for $142,296.00. [re Duffy Place, p. 36, line 18 - Oct 15, 2009 - re 1989 reference, CA-NP-281]

Mr. Ludlow suggested in his evidence (p. 36, Oct 15, 2009) that *"with respect to definitions of used and useful, it's beyond me to even begin to discussion (sic), but from my end when this was pulled together and it was thought about where we would build even Duffy Place in 1990, there was considerations given to using properties around this area, and with any utility there's property that is pulled together for different purposes and reasons, and that's basically all I can speak to on that topic, Mr. Chairman."* Then the question was put:

> "Q. *Basically it was banked for future possible use, wasn't it?*
>
> A. *That's exactly what is was, yes."*

There is certainly regulatoray precedent for land that has been banked for future use being included in rate base, but there also is precedent for achieving an equitable result with ratepayers when the utility ends up not needing the land.

The Process of Ratemaking (Volume 11) by Leonard Samuel Goodman (Public Utilities Reports, Inc. 1998) states at p. 799 that:

> "**USED AND USEFUL PRINCIPLE.** A commonly cited principle to decide whether particular properties should be included or excluded from the rate base calculation is whether the properties in issue will be in service in the test year or near-term future period. Regardless of the method of valuation of the rate base, it has long been held that investors are entitled to a return only upon that portion of their investment that is used and useful in the public service."

At page 812 of the text, **Property held for future use** is referenced. The text states,

> "**Property held for future use.** ***In general.*** Ordinarily the value of facilities held for future use is excluded from rate base as not used and useful in the public service, but several established exceptions apply. If property is owned by a regulated company, but not yet in service, there are circumstances under which it may yet be included in rate base if there is an anticipated use in the future. Regulatory commissions typically place limits on the period during which rate base treatment will be authorized for property held in suspense with more lenient rules applicable to land.
>
> Troxel considered standby plant an 'important subterfuge' for companies with outmoded equipment that is retained 'ostensibly to produce service if the regular plant breaks down or if the consumer demand increases suddenly.'
>
> Where a company can be found to have acted reasonably in the acquisition of sites for future facilities, a current return will be allowed on such investments, even though no definite in-service date has been established. As the Maryland commission noted, '[s]uch a policy optimizes opportunities for such acquisitions under more favourable market conditions'; and if the project is abandoned the proceeds will be accounted for the benefit of ratepayers, that is, 'above-the-line.' (emphasis added)

> The reasonable rule followed in California and sustained on appeal is that general property projected to be held for more than three years for future use will be disallowed. The commission thereby seeks to avoid utility speculation in real estate and divides the business risk of holding property between the company's investors and its ratepayers.
>
> California guidelines require that property held for future use must have specific future uses and cannot stay in this suspended state for periods exceeding,
>
> - 10 years for production plant and new transmission lines;
> - five years for other transmission and distribution plant; and
> - three years for general plant."

The Maryland Commission's "above the line" rationale would appear to be applicable to the current situation.

We would also draw the Board's attention to page 814 of the Goodman text and in particular the Puget Sound Power and Light Co decision of the Washington Commission in 1993 referenced in footnote 6.

The footnote indicates that the Board decided that in respect of the properties that had been held many years for future use, the utility would keep the gain on sale of properties "based on the period they were excluded from ratepayer support."

In the case of the Kenmount Road property, there was no period where the property that was sold was 'excluded from ratepayer support'.

The acquisition costs of the property were included in rate base. Municipal taxes were also paid on the property and recovered in rates. NP earned a return on this property which ratepayers paid in their rates. Hence, customer rates have included a carrying cost for this land. The sale price of the property was 628,000; hence the gain was 384,000. NP's position is that customers receive no part of this gain.

This approach which involves the customers carrying the cost of an asset (which does not appear to have actually been used to provide service as it was assembled to accommodate the Company's head office and ultimately was not required) but receive no share in the benefit is, in the view of the company *"consistent with past regulatory practice in this jurisdiction."* (CA-NP-184(c))

There is a question in this case of which party is in the best position to know when property of the utility is not being utilized or is surplus to the utility's needs. Clearly, it is the utility that is uniquely positioned to know this information. Ms. Perry agreed that there was no expectation on NP's part that the Consumer Advocate would need to ask on a yearly basis whether all of the utility's property is being used and useful. (Oct 19, 2009, p. 9-10)

At Table 2 of CA-NP-281, the Company has set out what its Approved Return on Rate Base has been from 1990 to 2008. The Consumer Advocate would adopt Mr. John Todd's direct evidence (Oct 27, 2009, p. 89) as follows:

> *"The resolution of this issue should be consistent with regulatory principles espoused by the Board in Order PU-19 2003, pages 15 to 16, in particular, the sixth principle end result which is, in compliance with the legislation, the end result must be fair, just, and reasonable from the perspective of both the consumer and the utility. How you do that is not obvious, but in particular, it may be appropriate to remove from rate base an amount that is equal to the original cost of the property, plus all related costs, including the carrying costs that have been included in rates over the years, as reflected in the return on rate base since the land was acquired. Under the circumstances, this calculation may provide the appropriate approach to determine the sort of equity salvage value for this asset that would be removed from rate base."*

Mobile River Watershed Dispute

The Company and the City of St. John's are presently engaged in a dispute pertaining to The Mobile River Watershed. CA-NP-138 shows that the company has forecast litigation costs of $275,000 in 2009 and $100,000 in 2010 in relation to this matter. Customers' rates in 2010 will specifically include the forecast 2010 costs of this litigation.

As CA-NP-265 notes the matter is presently before the Supreme Court - Trial Division.

It is not known how or when or if NP will be compensated for NP's Mobile River hydroelectric facilities. And it is not known, how or if or when customers may be affected by that issue. However, what is now known for certain is that customers by their rates are funding this litigation. If it should turn out that only NP's shareholders are entitled to any compensation that may arise from the resolution of this matter, NP's ratepayers will have funded a matter for the benefit of NP's shareholders. It is for that reason that a deferral account should be established to capture the liabilities and benefits associated with the litigation and ultimate resolution of The Mobile River Watershed dispute with the City of St. John's for appropriate disposition by the Board.

ALL OF WHICH IS RESPECTFULLY SUBMITTED at St. John's, Newfoundland and Labrador, this 6th day of November, 2009.

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The

PROCESS

OF

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not appropriate in such circumstances—at least under California law—to assign any portion of the cost adjustment to debt nor to allow any earnings thereon.[1]

Property normally should be valued no higher than the depreciated book cost to the seller, when a transfer of utility property occurs. An exception is permissible when the value of the transfer is less than fair market value, such as the alternative cost of providing the needed power supply for an electric utility.

A purchase above book value was justified in an Alabama case on the grounds there was a large demand for gas service that the transaction would help meet.[2] The Alabama commission approved the accounting for the purchase in excess of book value by, a) placing the book value in an acquisition adjustment account that would be included in rate base and amortized over 30 years; b) placing the offsetting liability in company equity; and c) placing the $500,000 difference between price and book value in a "deferred equity account" to be restored to equity (and to the main acquisition adjustment account/rate base) on the basis of $655 per customer as new customers were added to the system.

USED AND USEFUL PRINCIPLE. A commonly cited principle to decide whether particular properties should be included or excluded from the rate base calculation is whether the properties in issue will be in service in the test year or near-term future period. Regardless of the method of valuation of the rate base, it has long been held that investors are entitled to a return only upon that portion of their investment that is used and useful in the public service.[3]

The "used and useful" principle presupposes that the actual dollars of investment have been expended. If the properties are in service during the test period, the company may be entitled to include related operating and maintenance expense in its cost of service; but if the capital costs have not been incurred, it is not entitled to a return on a payment not yet made.[4] The accrual of an obligation to pay is insufficient to justify inclusion in rate base.[5]

Under the phrase "used and useful," the agency does not reach the question whether the capital was prudently invested, because even if it has been prudently invested but will not produce investments used and useful in the public service, the agency may exclude such properties from the rate base. The used and useful principle is also unrelated to "honest, economic and efficient" management standards. The agency may and in fact, absent contrary proof, will assume that the expenditures were made in an honest, economic, and efficient manner. The sole test is whether the capital in issue is representative of properties used and useful in providing the service under regulation.

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[1] Application of Cal.-Am. Water Co., 72 Cal.PUC 409 (1971). The California PUC gives no weight to purchase price in ratemaking valuations. Cuyamaca Water Co., 80 Cal.PUC 239 (1976).

[2] Re Alabama Gas Corp., 157 PUR4th 414 (Ala.PSC, 1994).

[3] Bluefield Water Works & Improvement Co. v. PSC of W.Va., 262 U.S. 679 (1923); Denver v. Denver Union Water Co., 246 U.S. 178 (1918); Willcox v. Consol. Gas Co., 212 U.S. 19 (1909).

[4] Re Williston Basin Interstate Pipeline Co., 52 FERC ¶61,170, 115 PUR4th 195, 203-04 (1990).

[5] *Id.*, 115 PUR4th at 204.

There is no requirement under the used and useful test that each expenditure associated with the property must have resulted from the particular regulatory use, rather than a prior use. Thus, if there is a cleanup cost attributable to a prior use of the property, which the company now wants to include in rates, so long as there is some current utility use for the property (such as parking and storage) the cleanup costs will be allowed.[1]

The "useful" aspect of the phrase also contains an element of whether ratepayers will benefit from the investment. A visitors center constructed by a utility that informs the public and serves as a meeting and training center may be disallowed; but a visitors center connected with a nuclear plant whose operating license may be extended may at the same time be allowed.[2]

The used and useful principle rests on basic cost definitions and concepts of fairness. If property is not used and useful, the addition of those capital costs to the current costs represents a basic misalignment of service costs. The fairer result, which as we shall later see is widely accepted, is for the agency, a) to recognize that a return *of* the capital costs is appropriate only as a cost chargeable to future ratepayers; and b) to recognize that a return *on* the capital costs should be allowed on a current basis.[3]

Relation to over-capacity and reserve margins. The courts never excused a "fair value" rate base from an inquiry into potential over capacity.[4] Excess capacity can be removed from the rate under the "used and useful" concept regardless of the valuation concepts underlying the rate base findings. "The circumstance that a road may have been unwisely built, in a locality where there is not sufficient business to sustain it," may be taken into account.[5]

The regulator is not required to accept the original cost figures booked by the regulated company, even if the cost accurately reflects the capital invested in the business. The company may have over-invested, as the Supreme Court early noted:[6]

> The original cost may have been too great; mistakes of construction, even though honest, may have been made, which necessarily enhanced the cost; more property may have been acquired than necessary or needful for the purpose intended. Other circumstances might exist which would show the original rates much too large for fair or reasonable compensation at the present time.

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[1] Re Peoples Nat. Gas Co., 144 PUR4th 333, 337 (Minn.PUC, 1993).

[2] Re Indiana Michigan Power Co., 116 PUR4th 1, 10-12 (Ind.URC, 1990). Indeed, a visitors center along the lines of the one at Sellafield in northern England can serve an important public purpose of informing ratepayers regarding the merits of the process of generating electricity in nuclear plants.

[3] *See* discussion of the "Allowance for Funds Used During Construction" and "Interest During Construction" at p. 807, *infra*.

[4] San Diego Land Co. v. Nat'l City, 174 U.S. 739, 757-58 (1899) (outstanding bonds not conclusive of value if property "cost more than it ought to have cost"); *and see* San Diego Land & Town Co. v. Jasper, 189 U.S. 439, 442-43 (1903); Darnell v. Edwards, 244 U.S. 564, 570 (1917).

[5] Darnell v. Edwards, 244 U.S. 564, 570 (1917).

[6] Stanislaus County v. San Joaquin C. & I.Co., 192 U.S. 201, 214 (1904).

trials.[1] Only services that are in the public tariffs and are available generally to ratepayers should be included in rate base.

Emission allowances under the Clean Air Act. Utilities may purchase sulfur dioxide emissions allowances at auctions held by the E.P.A. in advance of their needs to comply with the Clean Air Act.[2] The North Carolina commission permitted a utility to book a carrying cost on the net investment in allowances using the AFUDC rate applied to plant investments. The commission required that appropriate provisions be made to take into account related tax effects.[3] The investment in these allowances would be excluded from rate base until the year 2000, when initial compliance was required with the Clean Air Act.

The Wisconsin commission has stated that in general, since ratepayers are paying for cleaner fuels and plant modifications to enable electric utilities to burn cleaner coal, "it is equitable and in keeping with the principles of the federal legislation that the benefits of any allowance transactions should accrue to ratepayers."[4]

The Ohio commission permits the utility to retain the gains on emission allowance transactions, if those allowances are created from "below-the-line" (shareholder) funds. The commission advises its utilities that no movement of allowances between allowance banks funded from above-the-line as distinguished from below-the-line sources is permitted without prior commission approval.[5]

Facilities under repair or refueling. Facilities undergoing repair or refueling (such as nuclear stations) remain in rate base. The added outage costs are allowed in rates. The Connecticut regulatory authority in addition has held that true-up balances of outage costs of $5 million or more should be amortized over three years with carrying costs recognized whenever the amortization exceeds one year.[6]

For fossil fuel and hydro-power outages, especially where major overhauls occur on fossil units every four years, the authority allowed a three-year average of normal outage costs in rates as representative levels for the future.[7] It held that large swings from year to year in expenses could call for a more exact matching of expenses to revenues, but that fossil and hydro power outage expenses did not require such extraordinary treatment.

Property held for future use. ***In general.*** Ordinarily the value of facilities held for future use is excluded from rate base as not used and useful in the public service,[8]

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[1] Re Southern New England Tel.Co., 124 PUR4th 304, 321 (Conn.DPUC, 1991).

[2] Re Accounting for Carrying Costs of Emission Allowances, 148 PUR4th 361 (N.C.UC, 1994).

[3] For the inconsistency of the Illinois Coal Act with the U.S. Constitution, *see* p. 997.

[4] Re Advance Plans for Construction of Facilities, 136 PUR4th 153, 168 (Wisc.PSC, 1992).

[5] Re Trading and Usage of and the Accounting Treatment for Emissions Allowances By Electric Utilities, 141 PUR4th 121 (Ohio PUC, 1993).

[6] Re Connecticut Light and Power Co., 124 PUR4th 532, 552 (Conn.DPUC, 1991).

[7] *Id.* at 552-53.

[8] Bell Teleph. Co. of Nev., 18 PUR3d 209, 213 (Nev.PSC, 1957); Re Northeast Tel. & Teleg. Co., 1 PUR3d 33, 44 (Vt.PSC, 1953).

but several established exceptions apply. If property is owned by a regulated company,[1] but not yet in service, there are circumstances under which it may yet be included in rate base if there is an anticipated use in the future. Regulatory commissions typically place limits on the period during which rate base treatment will be authorized for property held in suspense with more lenient rules applicable to land.

Troxel considered standby plant an "important subterfuge" for companies with outmoded equipment that is retained "ostensibly to produce service if the regular plant breaks down or if the consumer demand increases suddenly."[2]

Where a company can be found to have acted reasonably in the acquisition of sites for future facilities, a current return will be allowed on such investments, even though no definite in-service date has been established. As the Maryland commission noted, "[s]uch a policy optimizes opportunities for such acquisitions under more favorable market conditions"; and if the project is abandoned the proceeds will be accounted for the benefit of ratepayers, that is, "above-the-line."[3]

The reasonable rule followed in California and sustained on appeal is that general property projected to be held for more than three years for future use will be disallowed. The commission thereby seeks to avoid utility speculation in real estate and divides the business risk of holding property between the company's investors and its ratepayers.[4]

California guidelines require that property held for future use must have specific future uses and cannot stay in this suspended state for periods exceeding,

- 10 years for production plant and new transmission lines;
- five years for other transmission and distribution plant; and
- three years for general plant.

Case-by-case exceptions can be granted if, a) there is a definite plan and need to retain the property in this status; b) economic analysis justifies the retention; and c) there are mitigating circumstances to require the retention.[5]

Property held for future use in California will be disallowed as not used and useful, where there is no definite, written plan for use.[6] Property held for future use may be removed from rate base where there are no specific dates on which it is expected to be placed in service, or after the customers have waited many years for some use to be made of the property. The standard here is not the prudence of the purchase, but rather whether the properties are in fact providing a benefit to ratepayers.

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[1] Property which is not yet owned in the test period, but is "expected to be acquired in the test year," does not qualify for inclusion in property held for future use. Re Hawaiian Elec.Co., 134 PUR4th 418, 462 (Hawaii PUC, 1992).

[2] Troxel, Economics, p. 368.

[3] Re Potomac Elec.Power Co., 124 PUR4th 1, 11 (Md.PSC, 1991).

[4] Pacific Tel.& Teleg.Co. v. Calif.PUC, 62 Cal.2d 634, 44 Cal.Reptr. 1, 401 P.2d 353 (1965); *and see* Re Gulf States Utils.Co., 159 PUR4th 54, 62 (La.PSC, 1994) (three year holding period allowed), citing Texas PUC Docket No. 8702.

[5] Re Southern Calif. Edison Co., 130 PUR4th 97, 144-45 (Cal.PUC, 1991).

[6] Re California Water Service Co., 155 PUR4th 417, 422 (Cal.PUC, 1994)

Where generating plant was purchased at $300 per kilowatt as compared to a cost for new construction of $1,500 per kilowatt, although the plant would not be needed for 18 years, the Colorado commission permitted its inclusion in rate base to recover the utility's out-of-pocket expenses, namely at a rate of return excluding cost of equity.[1]

The Florida commission disallowed a utility's share of a generating plant, when a) the utility's reserves were adequate without the new capacity; b) the utility planned to dedicate the new capacity to unit power sales in the years it expected a higher load than in the rate year; and c) the utility had asked for inclusion of the new capacity in rate base only after another buyer had defaulted.[2] The commission added that all profits and losses as well as any settlement with the defaulting buyer will accrue to stockholders; hence ratepayers should not be required to underwrite the power sales contract.

The Hawaii commission excluded property held for future use, when the utility had failed to make use of the property for 10 years and merely projected its use within the next 10 years. The commission held that the "countdown" of the period for properties held for future use began at the time the initial question was raised and decided by it in a 1983 proceeding.[3]

The Illinois commission in 1993 permitted a water company to keep property in rate base that had been acquired in 1971 for construction of sludge disposal facilities, which the company had continually attempted to avoid building. The commission sought to avoid penalizing the company for its continuing efforts to control costs, adding that at the same time there was no evidence it would be prudent for the company to dispose of the property at this time.[4]

The Texas commission included a planned but deactivated lignite burning generating station in rate base, when the affected utility had definite plans for the project within a 10-year period. Under the same standard, it excluded a planned transmission line and substation where construction would begin only in the year 2000; investment in a related mine was excluded from rate base and given no AFUDC, but the utility was permitted to capitalize the ongoing costs.[5]

The state of Washington commission compared the high returns paid over the years to the company on land held 20 years for future use with the relatively small increase in the market value; it found that there had "not been much benefit for the ratepayer"; noted that some properties are just "sitting"; and held that if property is not used within 20 years, the ratepayers should not continue to bear the carrying costs.[6]

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[1] Re Public Svc. Co. of Colorado, 148 PUR4th 1, 7 (Col.PUC, 1993).

[2] Re Gulf Power Co., 120 PUR4th 1, 10-11 (Fla.PSC, 1990).

[3] Re Hawaiian Elec.Co., 134 PUR4th 418, 462-63 (Hawaii PUC, 1992).

[4] Re Illinois-American Water Co., 141 PUR4th 40, 45-47 (Ill.CC, 1993).

[5] Re Houston Lighting and Power Co., 134 PUR4th 303 (Tex.PUC, 1991).

[6] Re Puget Sound Power and Light Co., 147 PUR4th 80, 142 (Wash.UTC, 1993). The utility would keep the gain on sale of the properties "based on the period they were excluded from ratepayer support."