1.0 BACKGROUND AND APPLICATION

1.1 Background

On November 22, 1993, BC Gas Utility Ltd. ("BC Gas") filed with the British Columbia Utilities Commission ("the Commission", "BCUC") an application to increase the rates, on an interim and permanent basis, of captive customers in the Lower Mainland, Inland and Columbia Divisions. The application, based on a two-year test period was for an increase of 9.21 percent on a gross margin basis effective January 1, 1994, and a further increase of 13.69 percent on a gross margin basis effective January 1, 1995. The application calculated the utility's required January 1, 1994 increases based on a proposed 33 percent common equity component of its capital structure and a 12.25 percent rate of return on common equity ("ROE"), the same figure awarded following the 1992 revenue requirements hearing. In addition, the applicant proposed a method of adjusting the allowed ROE for 1995.

By Order No. G-120-93, the Commission approved an interim increase which had been adjusted downward to incorporate an ROE of 11.20 percent to reflect a general decline in interest rates and the reduced yield on Government of Canada Long-Term Bonds ("long-term Canada bonds") from the time of the withdrawal of the BC Gas 1993 Application in May, 1993 to the date of the Order.

On November 30, 1993, West Kootenay Power Ltd. ("WKP") filed with the Commission, an application requesting a rate increase of 7.6 percent uniformly to all classes of service effective with consumption on and after January 1, 1994, along with a further increase of 5.6 percent on January 1, 1995. WKP's application calculated its required January 1, 1994 interim increase based on a proposed 44.04 percent common equity component of its capital structure and an 11.5 percent return on common equity.

By Order No. G-125-93, the Commission approved for WKP an interim rate increase to all customers of 5.7 percent that reflected an ROE of 11.2 percent and a deemed capital structure with a 39 percent equity component. The interim increase was adjusted downward by the Commission to reflect a general decline in interest rates and the reduced yields on long-term Canada bonds from the date of the 1993 Commission Decision on WKP's 1993 Revenue Requirements to the date of the Order and the targeted mid-year 1994 capital structure of 39 percent common equity determined by Order No. G-41-93.

On December 2, 1993, Pacific Northern Gas Ltd. ("PNG") applied to the Commission for approval to amend its gas tariff rate schedules on an interim and permanent basis by 6.66 percent on a gross margin basis effective January 1, 1994. PNG calculated its required interim and permanent 1994 rate increases based on a proposed 13.25 percent return on common equity, which was the same figure awarded following the last revenue requirements hearing, and a common equity component of its capital structure of 31.41 percent.

By Order No. G-121-93, the Commission approved for PNG an interim rate increase of 4.36 percent on gross margin that included an ROE of 12.20 percent to reflect a general decline in interest rates and the yields on long-term Canada bonds .

In adjusting the applied for rates of return on common equity on an interim basis, the Commission indicated that the lower return on common equity for interim increase purposes did not prejudice the cases of BC Gas, WKP or PNG in the permanent applications for revenue requirements.

By Order No. G-121-93, the Commission requested submissions from all interested parties with respect to the holding of a joint hearing to deal with the rates of return on common equity for PNG and BC Gas. On January 14, 1994, a pre-hearing conference was held with interested parties who expressed the view that a joint hearing would be beneficial. Subsequently, WKP asked the Commission to be included in the joint hearing.

By Order No. G-4-94, the Commission set down a public hearing to be held into the appropriate rates of return on common equity and capital structure for BC Gas, WKP and PNG ("the Applicants") to commence at 8:30 a.m., April 5, 1994 in the Commission's Hearing Room. Further, the Commission indicated that it wished to hear evidence on future processes or mechanisms that might be employed to improve the determination of ROE and capital structures in future years. In particular, the Commission identified the following questions on which it wished to hear evidence:

(i) what is the appropriate rate of return on common equity to be awarded each utility;

(ii) what is the appropriate capital structure for each utility;

(iii) should future joint hearings set the capital structure and rate of return on equity for individual utilities or should it be set for a phantom "low risk" utility only;

(iv) if the rate of return for the individual utilities are to be set, for what time period should the premium awarded each utility apply, i.e. should the premiums be determined annually or for a longer period of time;

(v) if the premiums are to last for more than one year, how should the rate of return on the phantom utility be adjusted to reflect changes in the financial climate, i.e. changes to the long term bond rate; and

(vi) when should the joint hearing on ROE and capital structures be held, e.g. late fall of the preceding year.

In a pre-hearing conference held February 14, 1994, it was agreed that the hearing should be segmented into two phases. The first segment, Phase A, would consider the development of a rate of return on equity for a benchmark set of low risk, high grade utilities. It would also explore the possibility of an automatic adjustment mechanism to vary, over time, the ROE's awarded individual utilities. Finally, this portion of the hearing would consider the future scope and timing of generic ROE proceedings. The second segment, Phase B, would examine the specific risk profiles of the three utilities, determine the appropriate premium off the benchmark ROE and determine the appropriate capital structure of each utility.

The hearing commenced April 5, 1994 with the evidentiary portion terminating April 15, 1994. Written final argument from the Applicants was filed on April 21, 1994 with final argument from the Intervenors filed on April 26, 1994. Reply argument from the Applicants was filed on April 28, 1994.

The decisions reached as a result of this hearing will also affect the rates of Centra Gas - Fort St. John District ("Centra-FSJ") and the British Columbia Power and Hydro Authority ("B.C. Hydro"). In a Decision dated March 11, 1994, the Commission accepted the premise that the appropriate ROE to be allowed Centra-FSJ would be the simple arithmetic average of the ROEs allowed PNG and BC Gas. In the case of B.C. Hydro, Special Direction #8 to the Commission requires the Commission to set a rate of return on equity for B.C. Hydro which allows B.C. Hydro to achieve an annual rate of return on equity equal to that allowed on a pre-income tax basis by the most comparable investor-owned energy utility regulated under the Utilities Commission Act ("the Act"). By Decision dated December 7, 1993 the Commission found the most comparable utility to be either WKP or BC Gas and indicated that it wished to hear further evidence as to comparability at the next B.C. Hydro Revenue Requirements Hearing.

1.2 The Applicants

BC Gas was formed as a result of the acquisition by Inland Natural Gas Co. Ltd. of the British Columbia Hydro and Power Authority Lower Mainland Gas Division in 1988. Following the acquisition, in July 1989 the four gas distribution companies of Inland Natural Gas Co. Ltd., Columbia Natural Gas Limited, Fort Nelson Gas Ltd. and B Gas Inc. were amalgamated under the new company name of BC Gas Inc. In July 1993, BC Gas Inc. was reorganized to create a holding company which holds all of the shares of the company owning the gas utility assets. The utility company changed its name from BC Gas Inc. to BC Gas Utility Ltd. and the holding company took the name BC Gas Inc.

BC Gas provides gas distribution services across much of the province to over 666,000 customers, of which 596,000 are residential, 69,000 are commercial and 1,000 are industrial customers. Its centres of operations include Fort Nelson, Prince George, Kamloops, Kelowna, Cranbrook and the Lower Mainland.

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PNG transmits and distributes natural gas in the west central portion of British Columbia. The 350 mile system begins at Summit Lake, near Prince George, where it interconnects with the Westcoast Energy Inc. ("Westcoast") pipeline system and terminates at the deep water ports of Kitimat and Prince Rupert. It is primarily an industrial gas transmission system. For 1994, volumes delivered to residential customers are expected to comprise approximately 5 percent of PNG's load, while volumes to commercial customers are expected to comprise an additional 5 percent of load. The balance is taken by industrial customers of which the Methanex Corporation ("Methanex") plant at Kitimat takes approximately 73 percent.

WKP provides electrical power to approximately 116,000 customers in the south east corner of the Province. Approximately 40 percent are served indirectly through the sale of power to municipal distribution utilities in Grand Forks, Nelson, Kelowna, Penticton, Summerland and through Princeton Light and Power Company, Limited, a private company serving Princeton and vicinity. Power is supplied from WKP's four plants on the Kootenay River, purchases from Cominco Ltd., and purchases from B.C. Hydro.

2.0 RATE OF RETURN ON EQUITY FOR A BENCHMARK SET OF UTILITIES

2.1 Introduction

The Commission received evidence with respect to the appropriate rate of return on equity for a benchmark set of utilities from several expert witnesses. For the Applicants, Dr. Robert Evans appeared on behalf of WKP, Dr. Stephen Sherwin and Ms. Kathleen McShane appeared on behalf of BC Gas, and Ms. McShane appeared on behalf of PNG. For the Intervenors, Dr. William Waters appeared on behalf of a group of wholesale electricity and industrial customers ("Wholesale Customers") while Drs. Lawrence Booth and Michael Berkowitz appeared on behalf the Consumers' Association of Canada (B Branch) and several other senior citizen or low income groups ["CAC(BC) et al"].

2.2 Economic Forecast

All the expert witnesses presented a forecast of economic conditions for 1994 and 1995 against which their specific return recommendations could be assessed. Although there were some differences in expectations with respect to items such as longer term inflation rates, there was substantial unanimity with respect to the interest rate expectations over the next two years. Dr. Evans indicated that the yield on long-term Canada bonds was expected to be in the order of 7.25 percent to 7.75 percent for both 1994 and 1995, with the emphasis on the upper end of the range, i.e. 7.75 percent (Exhibit 11C, page 2). Similarly, Dr. Sherwin and Ms. McShane projected the yield on long-term Canada bonds at 7.5 percent to 8.0 percent for 1994 (Exhibit 17, Tab 4, page 40). Dr. Waters suggested that yields on Government of Canada ten-year and over bonds would tend to concentrate around 7.75 percent (Exhibit 39, page 10) while Drs. Berkowitz and Booth projected long-term Canada bond yields averaging in the range of 7.75 percent to 8.25 percent, with rates in 1994 at the lower end of the range and at the upper end in 1995 (Exhibit 47A, page 10).

For the purposes of establishing the rate of return on equity for both a benchmark set of low risk, high grade utilities and for each of the Applicant utilities, the Commission accepts that the forecast yield on long-term Canada bonds will average 7.75 percent in 1994. In making this determination, the Commission is mindful of recent movements in capital markets, particularly the increase in long-term Canada bond yields from just over 7.0 percent at the beginning of the year to current levels which are in excess of 8.70 percent The Commission expects that these relatively high levels will not be maintained over the year.

2.3 Rate of Return on Equity Tests

2.3.1 Evidence of Dr. Evans

2.3.1.1 The Comparable Earnings Test

Dr. Evans indicated that for the return on equity to be considered fair it must meet three standards. It must: (i) permit the attraction of new common equity capital on reasonable terms; (ii) maintain the financial integrity of the utility; and (iii) be commensurate with returns being earned by other enterprises of similar risk (Exhibit 11A, page 21).

To evaluate the appropriate rate of return on common equity, Dr. Evans used three methods:

(i) The comparable earnings test, which measures the return on book equity, over a selected time period, achieved by a group of non-regulated companies believed to be of similar risk to utilities;

(ii) The discounted cash flow ("DCF") test, which estimates the investors' required rate of return on equity as the sum of the dividend yield plus the expected annual rate of growth in per-share dividends; and

(iii) The risk premium test, which estimates the necessary premium over and above the risk free interest rate, usually as measured by long-term government bonds, which must be paid by the utility to attract investors.

Dr. Evans applied the comparable earnings test to two groups of unregulated companies, one of which included and one of which excluded resource companies, which he judged to be of similar risk to utilities. To obtain his sample, he followed the following procedure. First, he selected all companies listed on the Toronto Stock Exchange ("TSE") 300 share index for which data was available for at least the past ten years. Second, he excluded companies which he believed had unusually high rates of capital turnover (eg. real estate, finance companies) and those which were subject to different accounting conventions (eg. oil and gas production companies). Third, he excluded any company having either a negative equity in any of the past ten years, a negative ten-year average return on equity, or a negative ten-year average pre-tax return on investment. Finally, he ranked the remaining 87 companies according to certain risk measures, including the coefficient of variation in pre-tax, pre-interest rate of return on investment; common equity ratios; and the coefficient of variation in rate of return on book common equity. He indicated these measures respectively reflected business risk, financial risk and investment risk (Exhibit 11A, page A2-A3). His sample was comprised of those companies with the lowest composite risk measure.

After choosing his sample, Dr. Evans estimated the rate of return on book equity earned by these companies over the period 1983 to 1992 and found that the initial indications were for a rate of return on equity for high quality, low risk unregulated companies of 13.5 percent to 14.0 percent. Dr. Evans adjusted this finding downwards to 12.25 percent to 12.75 percent to reflect such judgmental factors as expected lower corporate profits and lower inflation expectations (Exhibit 11A, pages 38 and 39).

Dr. Evans agreed that the comparable earnings test was based on historical data, that over time there could be changes in the risk profile of the sample companies, and that there was an element of judgment in the selection of a time period over which to apply the test (Exhibit 47A, Appendix C, page 1). However, he also indicated that these problems could be overcome through judgment (T. 152-156). Similarly, he agreed that the comparable earnings test did not measure the opportunity cost of capital but argued that it was not intended to do so. Instead, he contended that it provided a method of directly examining rates of return in relation to book value (T. 157 and 158). Dr. Evans agreed that accounting data did not necessarily reflect the true economic status of corporations but indicated that it was not being used to determine the market cost of money (T. 169). Finally, he agreed that there were differences in accounting treatments among companies that might affect the rates of return on book value and that changing price levels did complicate the application of the test (T. 170).

Dr. Evans disagreed with suggestions that his sample selection procedure, particularly the use of the coefficient of variation in book returns, led to the inclusion of firms with market power (Exhibit 47A, Appendix C, page 1). He indicated that there was no evidence of market power in the returns earned by the companies in his sample since they had all suffered due to economic restructuring (T. 107). Further, he indicated that one would expect to see a high achieved rate of return on low risk firms (T. 108 and 109).

2.3.1.2 The DCF Test

The DCF test is based on the proposition that investors purchase common equity shares with the expectation of receiving an infinite stream of dividend payments. As a result, the price paid for the shares can be viewed as the present value of the dividend stream, that is the sum of the dividend stream discounted by the investors' required rate of return. Assuming a constant expected rate of growth in dividends, the present value formula can be manipulated to show that the investors' required rate of return can be expressed as the sum of the current dividend yield, i.e. the current dividend divided by the current share price, and the expected annual rate of growth in per share dividends. Under the assumptions of the DCF model, the expected rate of growth in dividends per share is equal to the expected percentage growth in share price.

Dr. Evans applied the DCF test to the same set of sample companies used in the comparable earnings test. He indicated that recent spot dividend yields had been in the order of 2.25 percent while an assessment of experienced earnings, dividend and book value growth rates, all of which are sometimes used as proxies for share price growth, indicated growth expectations of 9.25 to 10.0 percent. This suggested an investors' required rate of return of 11.5 percent to 12.25 percent. Dr. Evans stated that this result, which measures the return on market share, had to be adjusted upward before it could be applied to a book value rate base, to allow the utility to issue new common share financing without diluting the book value of existing shares (Exhibit 11A, page 32). Therefore, he increased the investors' required rate of return by a flotation cost allowance which produces a nominal market to book ratio of 110 to 120 percent. Dr. Evans stated that the allowance was intended to cover the out-of-pocket expenses associated with new share issues, and to compensate investors for the risks associated with market pressure, i.e. the discount from current trading values necessary to ensure that new shares are absorbed by the market, and market breaks, i.e. declines in share prices unrelated to the particulars of the new issue. With the addition of the flotation allowance, he estimated the required rate of return on book value to be in the range of 12.4 percent to 13.3 percent (Exhibit 11A, page 41).

Although Dr. Evans provided the results of the DCF test, he cautioned that investor growth expectations and experienced growth performance had been subject to fairly erratic trends and, therefore, the DCF approach was less useful and reliable than it might otherwise have been (Exhibit 11A, page 40). Consequently, Dr. Evans placed little reliance on the results of this test when determining his final recommendations.

2.3.1.3 The Risk Premium Test

Dr. Evans examined the results of three studies which estimated the historical differentials between achieved market returns on common equity and long-term debt securities: The Task Force on Retirement Income Policy study ("Task Force study"); the Canadian Institute of Actuaries study ("the CIA study"); and a study conducted by Professors Hatch and White of the University of Western Ontario ("the Hatch and White study").

The Task Force study, which covers the period 1920 to 1992, indicates that the equity risk premium fell within a range of 3.0 to 3.3 percentage points, depending on the specific time period examined and the calculation used. The CIA study, which covers the period 1924 to 1992 for Canadian data and the period 1943 to 1992 for U.S. data, indicates that the equity risk premium is approximately 4.25 to 4.5 percentage points based on Canadian data and 7.0 to 7.25 percentage points based on U.S. data. The Hatch and White study, which covers the period 1950 to 1987 and calculates the premium for both the whole period and several sub-periods, indicates that the risk premium ranges from 3.36 percentage points to 5.93 percentage points, except for the most recent sub-period which showed a negative risk premium.

Based on these studies, Dr. Evans indicated that a not unreasonable point estimate of the market risk premium was 6.0 percent (Exhibit 12, Tab 2, Question 9).

Dr. Evans evaluated the results of these studies using seven qualitative factors such as changes in tax policy, recent downturns in corporate profits and the relative risk of low risk utilities versus the market as a whole. Based on this evaluation, he determined that the risk premium applicable to low risk, high grade utilities was 3.5 to 4.0 percentage points for a mid-point of 3.75 percentage points. When added to the mid-point of his forecast for long-term Canada bonds (7.5 percent), he calculated the resulting investors' required rate of return at 11.25 percent. Dr. Evans agreed that he had not quantified the judgments he made but that they reflected studies carried out over a number of years (T. 65).

Dr. Evans did not agree with the proposition that it was inappropriate to rely, in part, on U.S. data in determining the risk premium since he believed that restricting his attention to studies that focused solely on Canadian data did not allow for an assessment of all the investment alternatives available and would not reflect the actual flow of investment dollars (T. 93). However, he did agree that the measured risk premium was very sensitive to the time period over which it was measured (T. 60).

As with the DCF test, the risk premium test measures the return on market shares. Therefore, Dr. Evans applied his flotation cost adjustment and determined that the appropriate rate of return on book equity for a low risk, high grade utility was 11.9 percent to 12.5 percent. He disagreed with the suggestion that flotation costs need not be paid where there is only one shareholder, stating that the costs are incurred by the parent company, even if not directly by the subsidiary utility. Further, he suggested that not allowing the flotation costs would make the cost of capital dependent on the ownership of the utility and would violate the "stand alone" principle (T. 135).

Dr. Evans indicated that he had placed greatest emphasis on the risk premium test, lesser emphasis on the comparable earnings test, and little emphasis on the DCF test (T. 47). As a result, he found that the appropriate ROE for a low risk, high grade utility was 12.4 to 12.9 percent.

2.3.2 Evidence of Dr. Sherwin and Ms. McShane

2.3.2.1 The Comparable Earnings Test

Dr. Sherwin and Ms. McShane agreed with Dr. Evans as to the three principle standards which should be satisfied in setting the ROE and the three tests which should be used to estimate the ROE (Exhibit 17, Tab 4, page 1).

Dr. Sherwin and Ms. McShane applied the comparable earnings test to a sample of 26 companies which they judged to be of similar risk to low risk, high grade utilities. The initial group of companies was selected from consumer oriented industries, which they indicated had relatively greater stability than extractive industries. In addition, the initial group was limited to those firms which had sufficient historical and market data to cover the period 1984 - 1992, a common equity component of $50 million or more, and 125,000 common shares or more traded annually. Firms which had cut dividends more than 25 percent or had not paid dividends within the period were excluded. The 52 firms which remained after the initial selection procedures were ranked by four risk measures: (i) coefficient of variation of book returns; (ii) coefficient of variation in earnings before interest and taxes; (iii) the five year beta (1988 - 1992); and (iv) the five-year standard deviation of market returns. The 26 companies which had the lowest composite risk ranking formed the sample.

Based strictly on historical data for the 1984 - 1992 time period, which Dr. Sherwin and Ms. McShane characterized as a normal cycle, they found that the achieved equity return by low risk industrials was 12.9 percent (Exhibit 17, Tab 4, page B-4). However, the witnesses expressed concern that the current cycle was not normal and that this level of earnings would not be achieved due to massive industrial restructuring and an economic downturn at the start of the cycle (Exhibit 17, Tab 4, page B-5). As a result, they made a forecast of expected earnings per share based on estimates provided by the Institutional Brokers Estimate System ("IBES") for 1993 and 1994 and an assumption that earnings per share growth for the succeeding years would reflect the pattern of the last business cycle. Based on this forecast, which the witnesses agreed contained a great deal of speculation (T. 292), they estimated that returns to low risk industrials for the current cycle would be in the order of 11.75 percent. Therefore, they estimated the achieved return on book equity at 11.75 to 13.0 percent (Exhibit 17, Tab 4, page B-6).

After determining the return for low risk industrials, Dr. Sherwin and Ms. McShane compared the risk of the sample group to that of low risk, high grade utilities. Using a discounted cash flow approach, they indicated that a downward adjustment of 50 basis points would be warranted for a low risk, high grade utility. Therefore, they indicated that the comparable earnings test indicated an ROE on book equity for low risk, high grade utilities of 11.25 to 12.5 percent.

Dr. Sherwin and Ms. McShane agreed that the comparable earnings test did not measure the cost of attracting capital but indicated, as did Dr. Evans, that it was not intended to do so. Further, they agreed that the use of historical earnings to determine the appropriate rate of return on book equity was only appropriate if past economic conditions were expected to be reasonably similar to prospective conditions, hence their use of forecast earnings in the application of the test (Exhibit 18, Appendix G, page 1). In addition, they agreed that accounting data did not reflect the true economic status of the corporation and that there were differences in the accounting treatment accorded different companies which affected the calculation of book return (T. 391). However, they rejected the suggestion that the use of the coefficient of variation on book returns as a sample screen led to the inclusion of firms with market power. Instead, they stated that, as their direct evidence showed, they had tested the sample to insure that this did not occur (Exhibit 18, Appendix G, page 2). Finally, they defended the continued use of the comparable earnings test on the grounds that regulation continues on an original depreciated cost basis (T. 394).

2.3.2.2 The DCF Test

Similar to the approach taken by Dr. Evans, Dr. Sherwin and Ms. McShane also applied the DCF test to their sample of 26 low risk industrials. Based on a dividend yield of 2.5 percentage points and an estimated dividend per share growth rate of 9.5 percent, they found that the investors' required rate of return, or "bare-bones" return, was 12.0 percent. This estimate was adjusted downward by 50 basis points to reflect the lesser risk of utilities as discussed above.

Dr. Sherwin and Ms. McShane agreed with Dr. Evans that this result, which reflects return on market value, needed to be adjusted upwards to allow the utility the opportunity to issue new common share equity without risk of dilution to existing capital. Therefore, the witnesses increased the investors' required rate of return by a flotation cost allowance which produces a nominal market to book ratio of 115 percent. This resulted in a rate of return on book equity of 12.6 percent.

Although the witnesses presented the results of the DCF test, they indicated that they placed little reliance on it due, in part, to the difficulty of obtaining objective measurements of investor growth expectations (Exhibit 17, page 8).

2.3.2.3 Risk Premium Test

In addition to the comparable earnings and DCF tests, Dr. Sherwin and Ms. McShane undertook three risk premium studies. The first study measured the risk premium as the difference between the DCF cost of attracting equity for a sample of high grade utilities and the corresponding yield on long-term Canada bonds for the period 1976 to 1993. The witnesses estimated the DCF cost of attracting equity as the sum of the quarterly dividend yield adjusted for growth for each period plus a weighted average of achieved five and ten year dividend growth rates and retained earnings growth for the high grade utilities. Different weighting alternatives were used to give a range of DCF costs (Exhibit 18, page A-4).

Dr. Sherwin and Ms. McShane stated that the study indicated an inverse relationship between interest rates and risk premiums (see Chapter 4.0 for a more complete discussion of this issue) but showed a risk premium of 4.3 percentage points when interest rates were below 9.0 percent. The witnesses then regressed the quarterly risk premiums estimated under the various growth scenarios against the corresponding quarterly long-term Canada bond yields with and without the addition of a second independent variable, quarterly five year betas. Assuming long-term Canada bond yields at 7.75 percent, these regressions indicated a required risk premium in the range of 3.75 to 4.5 percent. As a result, Dr. Sherwin and Ms. McShane indicated that the appropriate risk premium for high grade utilities was 4.0 percent (Exhibit 18, page A-10).

The witnesses rejected the proposition that the DCF based risk premium study suffered from upward biased estimates of expected growth, stating that the five- and ten-year dividend growth rates reflected factually experienced growth rates (Exhibit 18, page 16). Further, although they recognized their estimate of the retained earnings growth rate of 5.5 percent had not been achieved on an annual basis since the mid-1980s, they stated that this was only one of seven scenarios (Exhibit 18, page 18).

Similar to the risk premium study undertaken by Dr. Evans, the second study measured the risk premium for the stock market as a whole and then made adjustments for the lower risk of utilities. To estimate the risk premium, Dr. Sherwin and Ms. McShane utilized the Task Force study, the CIA study and the Hatch and White study used by Dr. Evans, although the time periods studied were not identical, as well as the Ibbotson and Sinquefield study of U.S. security returns. These studies indicated risk premiums from 3.1 to 6.9 percentage points depending upon the time period examined and the holding period assumed. When these results were assessed against a variety of considerations that the witnesses indicated may have affected the achievement of past returns or could affect the achievement of future returns, they concluded that a conservative estimate of the market risk premium was 5.0 percent (Exhibit 18, page A-17).

After establishing their estimate of the market premium, the witnesses adjusted it to reflect the lesser risk of utilities as measured by utility betas, the standard deviations of utility market returns, and the historic market performance of gas and electric utilities relative to that of the market as a whole (Exhibit 18, page A-17). Their data indicated that the beta for the sample of high grade utilities was 0.44, that the standard deviation for the TSE gas/electricity utility index was approximately 85 percent of the TSE 300 values, and that the gas/electricity utility index has outperformed the TSE 300 (Exhibit 18, pages A-18 and 19). As a result, Dr. Sherwin and Ms. McShane concluded that the appropriate risk premium for a high grade utility was 3.5 percentage points.

The witnesses did not accept the proposition that data from the pre-1956 period was of limited value in assessing the equity risk premium (Exhibit 18, page 12); nor did they accept that U.S. data on equity premiums should be ignored. Instead, they stated that U.S. data was relevant since a significant proportion of incremental investment funds were being channeled into foreign investments (Exhibit 18, page 13).

The third study calculated the achieved differentials between utility stock returns and the yield on long-term Canada bonds. The study found that over the period 1956 to 1993, the achieved risk premium on the TSE utility index was 3.4 percent and 4.5 percent on the gas/electric utility sub-index.

Taking the three risk premium studies together, Dr. Sherwin and Ms. McShane indicated that the utility risk premium was in the range of 3.5 to 4.0 percent, with emphasis on the upper end of the range. When combined with their forecast of long-term Canada bond yields, this suggested a bare bones investors' required rate of return on 11.5 to 11.75 percent or a mid-point estimate of 11.625.

As with the DCF test, the risk premium test measures the return on market shares. Therefore, the witnesses applied their flotation cost adjustment mechanism and determined that the appropriate rate of return on book equity for a low risk, high grade utility was 12.7 percent.

Based on the three tests, Dr. Sherwin and Ms. McShane indicated that the appropriate rate of return for a high grade, low risk utility falls within the range of 12.25 to 12.75 percent. In arriving at this conclusion, the witnesses gave 60 percent weight to the risk premium tests, 30 percent weight to the comparable earnings test, and 10 percent weight to the DCF test (Exhibit 17, Tab 4, page 2).

2.3.3 Evidence of Dr. Waters

Dr. Waters indicated that he relied upon the same three basic principles enunciated by Drs. Evans and Sherwin and Ms. McShane when making his determination of the appropriate rate of return on equity to be awarded utilities. However, unlike the witnesses appearing for the Applicants, Dr. Waters did not undertake a comparable earnings test because, in his views, (i) the concept of comparable earnings does not necessarily have any relationship to the concept of a fair return, and (ii) the measurement of comparable earnings, which are based on accounting data, provides results which are difficult to compare meaningfully across companies and across time periods (Exhibit 39, page 100).

2.3.3.1 The Risk Premium Test

As the starting point to his risk premium test, Dr. Waters considered five studies: the CIA study for the period 1924 to 1992; the Hatch and White study for the period 1950 - 1987; the Task Force study for the period 1920 - 1978; a study by M.J. Gordon and L.I. Gould ("the Gordon and Gould study") for the period 1956 - 1982; and the 1992 Investment Returns publication by Scotia McLeod Inc. (Exhibit 39, page 73). In addition, Dr. Waters made reference to the Ibbotson and Sinquefield study. Based on these studies, he found that the achieved market risk premium was 4.4 percentage points for the 1950-1993 period and 3.8 percentage points for the 1926-1993 period. As a result, Dr. Waters estimated the required market risk premium at 4.0 to 4.5 percent and used 4.5 percent in his application of the risk premium test.

Dr. Waters indicated that he considered the 4.5 percent value to overestimate the required equity risk premium since he believed it was greater than the value which investors had anticipated on a prospective basis. Specifically, he indicated that unforeseen large inflation driven increases in interest rates in the 1970s and 1980s had resulted in bond holders failing to achieve the return on bonds they had prospectively anticipated (Exhibit 39, page 76) so that the historical spread between equity and debt returns was wider than had been anticipated prospectively.

Dr. Waters indicated that unanticipated inflation had led to the inclusion of a purchasing power risk premium, which he estimated at 70 to 100 basis points (Exhibit 39, page 78), in the yield on long-term bonds. In contrast, he indicated that investors in utility shares enjoyed the potential of having their return subject to timely review and adjustment to offset the effects of inflation (Exhibit 39, page 71). As a result, he indicated that an argument could be made for reducing the estimate of base bond yields to which the risk premium was applied (Exhibit 39, page 76). However, he indicated that the purchasing power risk premium could be offset by the amount contained in achieved rates of return on bonds for having borne this risk and the prospective compensation, if any, required by equity investors for bearing this risk. As he was unable to estimate the amount of these two items, he made no quantitative adjustment for purchasing power risk in his estimate of the market equity risk premium (Exhibit 39, page 79).

Having established the risk premium for the equity market as a whole, Dr. Waters estimated the relative risk of low risk, high grade utilities using five risk measures: (i) beta; (ii) standard deviation of achieved rates of return; (iii) maximum drop in share price over 12 months; (iv) maximum percentage decline in per share earnings; and (v) deviation around the trend in per share earnings. Based on these measures, he determined that the risk exposure of low risk utilities was no more than one-half that of the equity market as a whole (Exhibit 39, page 83) or 2.3 percentage points (Exhibit 39, page 88). In addition, Dr. Waters used the same set of risk measures to estimate the relative risk for a sample of low risk industrial companies which he found to have approximately two-thirds the risk of the market as a whole, or 3.0 percentage points.

When combined with Dr. Waters' estimate of the yield on long-term Canada bonds, this suggests that the investors' required rate of return for low risk high grade utilities is 10.0 percent. However, Dr. Waters added to this estimate a 50 basis point cushion which he indicated was a margin of safety intended to cover the underwriting and issue costs associated with new issues of common equity and to minimize the possibility of dilution of existing shareholders' equity (Exhibit 39, page 4). Dr. Waters rejected the notion that the cushion should be large enough to permit new shares to be issued without risk of dilution even in the face of severe market breaks or market pressure since he indicated that compensation for these risks was already captured in the investors' required rate of return.

Dr. Waters agreed that the estimate of the equity market risk premium given in his current testimony was 150 to 190 basis points lower than that given in testimony before the BCUC dated February 1992. He stated that this reflected the inclusion of data for the period 1988 to 1993 in the current testimony as well as a change to the use of geometric rather than arithmetic means in calculating the premium (T. 707). Further, he agreed that he had made other adjustments to his methodology, primarily relating to the use of qualitative rather than quantitative adjustments for purchasing power risk (T. 709-714). Finally, he indicated that, despite these changes, his estimate of the utility risk premium had not changed substantially (T. 714).

2.3.3.2 The DCF Test

In addition to the risk premium test, Dr. Waters undertook a DCF analysis based upon a sample of utilities. In order to avoid the problem of circularity, he did not rely on historical utility dividend growth rates but instead made an explicit forecast of the rates of return which investors could expect Canadian utilities to earn over the near future. This was used in turn to derive a growth rate which he plugged into the DCF model. Based on annual rates of return of 12.0 percent, which he characterized as optimistic, and an earnings retention rate of one-third, Dr. Waters estimated a growth rate of 4.0 percent. When combined with the estimated dividend yield of 5.4 percent, this suggests an investors' required rate of return of 9.4 percent. As with the risk premium test results, Dr. Waters added a cushion of 50 basis points to obtain a final result of 9.9 percent.

Based on these two tests, Dr. Waters found that the required rate of return for a low risk high grade utility was 10.0 to 10.5 percent.

2.3.4 Evidence of Drs. Berkowitz and Booth

Drs. Berkowitz and Booth developed their estimate of the required rate of return on equity through applications of the DCF and risk premium tests. They did not use the comparable earnings test which they characterized as being extremely sensitive to sample selection procedures (Exhibit 47A, page 14).

2.3.4.1 The Risk Premium Test

Two types of risk premium assessments were made. First, the witnesses examined data from the CIA study and from the Scotia McLeod Handbook of Debt Market Indices to determine the difference in achieved return between equities and long term debt. Although they identified a number of problems with the data and with various statistical methods of calculating the equity premium, they estimated that the market risk premium was 3.5 to 4.0 percent (Exhibit 47A, Appendix D, page 6). This estimate was not derived mechanically from any of the studies.

The witnesses used two measures to establish the risk of utilities relative to the market: betas, which they indicated measured the incremental risk of holding a stock in a diversified portfolio, and the standard deviation of ROE (Exhibit 47A, page 17). They stated that utility betas had fluctuated in a range of 0.35 to 0.65 and were currently about 0.45 to 0.5. In addition, they estimated the standard deviation of ROE of the regulated sector as being 30 percent as variable as that of unregulated firms. Based on these measures, they indicated that the appropriate risk premium for utilities was 1.58 to 2.00 percentage points, giving rise to an investors' required rate of return on 9.33 to 10.25 percent, with a best estimate of 9.81 percent.

The witnesses were aware of the view that the Capital Asset Pricing Model, of which their model is a variant, tends to underestimate the cost of capital for low beta firms; however, they indicated that the empirical studies which led to this view were based on Treasury Bill yields whereas their model used long-term Canada bond yields (T. 969).

Although the witnesses provided an estimate of the premium that equity holders require over long-term debt, they indicated that a preferable method would be to estimate the premium between common and preferred shares since this eliminated certain distortions that arose because of the changing tax features of debt versus equity securities (Exhibit 47A, page 21). Using the Moss Lawson and Burns Fry Preferred Share indices, they found that the premium over preferred shares required by common share investors in telephone utilities was 1.0 to 2.5 percentage points. Assuming that preferred shares maintained the relationship to long-term Canada bonds found over the period February 15 to August 15, 1993, this implied that the investors' required rate of return was 9.43 to 10.56 percent, with a midpoint of 10.0 percent. The model was not applied to energy utilities since Drs. Berkowitz and Booth found only a weak link between equity prices and earned return for these companies. The witnesses postulated that this reflected the fact that the discrepancy between allowed and actual return on equity was caused primarily by weather deviations from normal to which, because it was random, investors did not react strongly (Exhibit 47A, page 23).

2.3.4.2 The DCF Test

In addition to the risk premium tests, Drs. Berkowitz and Booth undertook two DCF tests: a components of growth model and an inflation adjusted growth model. Both methods calculated the investors' required rate of return using samples of telephone and energy utilities. Depending on the make-up of the sample and the particular model used, these studies indicated that the investors' required rate of return ranged from 9.25 to 12.42 percent, with an overall DCF estimate of 10.23 percent (Exhibit 47A, page 32).

Drs. Berkowitz and Booth disagreed with a suggestion that their DCF tests contained circularity problems since they were estimating the growth rate over a long period of time, which contained different business cycles, interest rates and inflationary environments. In addition, they indicated that to ignore utility data because of the circularity concerns was to ignore the information most relevant to utilities (T. 1045).

A simple arithmetic average of the results of all the tests indicated that the investors' required rate of return was 10.07 percent. However, the witnesses stated that a fair rate of return for a generic average risk regulated utility would be in the range of 10.0 to 11.0 percent with a recommended point estimate of 10.5 percent. For low risk utilities a reduction of 10 basis points was recommended (Exhibit 47B, page 11) Drs. Berkowitz and Booth indicated that the premium in their recommendation over the arithmetic estimate reflected concerns that the estimates were subject to error, the existence of flotation costs associated with new financings, and changes in business risk, especially with respect to telephone utilities, which might not be reflected in the historic data.

2.4 Commission Determinations

The Commission has reviewed the evidence placed before it and agrees with those witnesses who indicated that a DCF test based on a sample of low risk industrial customers is of limited use in the current economic climate. In addition, the Commission is concerned that DCF tests based on historical utility data may be subject to circularity problems. Equally, the Commission shares concerns expressed by Dr. Waters and by Drs. Berkowitz and Booth that the comparable earnings test does not measure the opportunity cost of capital. While the Commission recognizes that Dr. Evans, Dr. Sherwin and Ms. McShane have stated that this is not the objective of the comparable earnings test, the Commission notes that the opportunity cost principle encompasses the three regulatory standards referred to by several witnesses as important in determining the appropriate rate of return on common equity (Exhibit 17, page 1).

Therefore, in this Decision, the Commission has placed primary reliance on the various risk premium tests presented, (with the exception of the preferred share approach), in making its determination of the

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appropriate rate of return on equity for a low risk, high grade utility. The comparable earnings and DCF test results have been used primarily as checks upon reasonableness. With respect to the preferred share approach espoused by Drs. Berkowitz and Booth, the Commission is concerned about the apparent limited applicability of the model to energy utilities but is willing to entertain new evidence on this approach in future proceedings.

The Commission notes that the determination of the appropriate equity risk premium to use in setting the ROE for the set of low risk, high grade utilities requires the exercise of informed judgment. Although historical studies can be used to establish a starting point for the estimate of the market risk premium, these studies show a wide dispersion of results depending on the time period and measurement techniques used. In addition, the measured market risk premium estimates must be adjusted to reflect concerns about the applicability of past time periods to future time periods. On balance, the Commission finds that these concerns suggest that the measured market risk premium over-estimates the market risk premium which investors currently anticipate. The Commission finds that the market risk premium is approximately 4.5 to 5.0 percent.

Judgment must also be applied to determine the risk premium required by investors in utility stocks vis-a-vis that of the market as a whole. Different witnesses used different techniques to estimate this value ranging from a strictly qualitative approach to assessments of relative risk based on various statistical measures. Although the Commission recognizes that no one statistical measure of risk may adequately capture investors' perceptions of the risk of utilities relative to the market, the Commission finds that the combination of the various statistical measures indicate that utilities are approximately one-half as risky as the market as a whole.

Therefore, the Commission determines that the required rate of return on equity for a low risk, high grade utility is 10.5 to 10.75 percent based on a long-term Canada bond yield of 7.75 percent. For the purposes of calculating rates, the Commission establishes 10.75 percent as the benchmark rate of return, recognizing that bond yields have recently been above 7.75 percent. This return incorporates a 50 basis point cushion which the Commission expects to be sufficiently generous to cover the risk of dilution and cost of new share issues in other than extraordinary market circumstances.

3.0 UTILITY RETURN ON EQUITY AND CAPITAL STRUCTURE

3.1 WKP Capital Structure and Return on Equity

3.1.1 Position of WKP

WKP has applied for a rate of return of 11.5 percent on a common equity component of 43.96 percent for 1994 and 11.75 percent return on a common equity component of 38.76 percent for 1995 (T. 1504-1505). In the original application WKP had applied for a common equity of 44.04 percent in 1994 and 41.6 percent for 1995; however, this was subsequently reduced to reflect changes in the company's Capital Plan. The applied for ROEs are lower than the 12.0 to 12.5 percent recommended by Dr. Evans (Exhibit 11A, page 3) and reflect a desire by the company to limit the size of the rate increase to customers (T. 530). The common equity components requested by WKP are also higher than those specified by the Commission in its June 9, 1993 Decision in which it directed WKP to undertake the necessary steps to achieve a common equity component of approximately 38 percent by year-end 1994 and approximately 35 percent by year-end 1995. By letter dated March 14, 1994 (Exhibit 1), WKP applied for a reconsideration of the capital structure decision on the basis that the information put forward in the 1993 hearing was insufficient for the Commission to reach its decision on this item. In particular, the 1993 hearing record did not include an Exhibit showing the impact of a 35 percent common equity component on the interest coverage ratios of the utility (T. 532).

By way of Order No. G-125-93, the Commission established interim rates for WKP which reflected a rate of return on common equity of 11.2 percent and a common equity component of 39.0 percent. The Commission stated that these determinations did not prejudice the utility's application.

In order to establish the appropriate capital structure and return on equity for WKP, the utility provided evidence regarding the specific risks and circumstances facing the company. Dr. Evans identified three general types of risk to which a utility is exposed: business risks which relate to the physical, market and regulatory environment, i.e. risks which affect the assets of the utility; financial risks which relate to the manner in which the assets of the utility are financed; and investment risks which are the combination of the two (Exhibit 11A, pages 4 and 5).

In his primary evidence, Dr. Evans did not discuss WKP's business risk since he indicated that he had undertaken a detailed assessment in the evidence prepared for the 1993 WKP Revenue Requirements hearing and did not believe circumstances had changed significantly (Exhibit 11A, page 6). As a result, he stood by his previous assessment that WKP required a common equity component of 40 to 45 percent (Exhibit 11A, page 6 and 7).

In contrast, Mr. Ash, Senior Vice-President and Chief Operating Officer for WKP, indicated that business risks had increased. In particular, he noted that B.C. Hydro's obligation to serve WKP had been capped at 200 MW so that WKP had to find other options to meet demand (Exhibit 35, page 1); that there were prescheduling risks associated with the limited B.C. Hydro supply (T. 575); that capital expenditures were predicted to cause the rate base to double in five years (Exhibit 35, page 2); and that there was potential instability with WKP's customer base (Exhibit 35, page 3) in that several major wholesale customers had not renewed contracts with WKP and might have the opportunity of contracting with B.C. Hydro for service (T. 571).

Dr. Evans warned that if the equity component were reduced to the levels contemplated in the previous Commission Decision, then WKP's debt ratios would increase and interest coverage ratios would decline from the 2.4 times he estimated based on the application. He indicated that a decline from this level could result in a downgrading of WKP's debt (Exhibit 11A, page 15) which could severely limit the utility's access to capital markets at a time when it was important to ensure that WKP was able to finance its construction program (Exhibit 11A, page 12). However, Dr. Evans agreed that bond ratings agencies do not look at interest coverage ratios alone or at a single year only when determining a bond's rating (T. 646). Mr. Ash also indicated that a downgrade in WKP's bond rating and a weak capital structure could lead to higher financing costs for capital expansions (T. 581). Further, he noted that, in light of WKP's capital expansion program, it would not be prudent at this time to pay out equity to their shareholder in order to achieve the lower equity component specified in the Commission Decision (T. 548).

Despite his assertion that the common equity components contained in the application were appropriate, Dr. Evans indicated that he had adjusted the ROE that he would otherwise have recommended downward by 25 basis points to reflect the thick equity components which WKP wished to maintain to preserve its current debt rating (Exhibit 11A, page 16). He showed that the increase in revenue requirement assuming his recommendation and the application capital structure versus his recommendation plus 25 basis points and a common equity component of 36.5 percent was approximately $200,000 (Exhibit 44, page 2). In addition, he noted that the company had applied for an ROE which was less than he had recommended.

Dr. Evans compared the financial risk faced by WKP to that faced by four comparison Canadian electric utilities and concluded that they faced similar risks (Exhibit 11A, page 11). To make this assessment, he compared the debt components, interest coverage ratios and fixed charge coverages contained in the application with the 1992 data for the comparison utilities. He found that WKP's application contained a higher debt component (51.5 and 56.7 percent versus 37.0 to 43.2 percent) and lower interest coverage ratios (2.4 times versus 2.7 to 3.8 times) than the comparison utilities, but enjoyed higher fixed charge coverage ratios than all but one of the other utilities (2.4 times versus 1.9 to 2.3 times) (Exhibit 11A, page 11). This reflects the low level of preferred shares in WKP's capital structure versus the other utilities. Nonetheless, Dr. Evans indicated that, from a bondholder's perspective, interest coverage ratios were the more important indicator of risk (Exhibit 11A, page 11).

Dr. Evans also compared WKP's investment risks to those of a high grade, low risk utility and to those of the unregulated companies that he used in undertaking the comparable earnings and DCF tests discussed in Chapter 2 of the Decision. Based on a comparison of stock and bond ratings, Dr. Evans stated that investors were likely to consider WKP to be of greater risk than a high grade, low risk utility such as TransAlta or the unregulated companies sample. As a result, Dr. Evans indicated that the ROE for WKP should be adjusted upward by 25 basis points from that which he would recommend for a high grade, low risk utility.

Finally, Dr. Evans indicated that he had adjusted the flotation costs allowance he would normally recommend downward by 40 basis points (See Section 2.3.1.3) to account for the fact that WKP recovers its out of pocket financing costs directly from its customers in its cost of service (Exhibit 11A, page 33).

3.1.2 Position of Wholesale Customers

Dr. Waters indicated that the fundamental risks associated with the operations of a utility derived from the markets for its services and its input resources (Exhibit 39, page 33). With respect to WKP, Dr. Waters stated that the possibility of operating revenues falling short of operating and financing costs was minimal since the absence of competition from other suppliers and the limitation on substitution of other energy types meant demand forecasting was relatively easy; most of WKP's costs were fixed in advance or subject to only small quantity variations; and WKP enjoyed some discretion with respect to the timing of some of its expenditures (Exhibit 39, pages 62-63). He indicated that WKP's focus on distribution of electricity and declining industrial load meant that it would not be subject to the same kinds of competitive issues that other utilities might face (T. 846-47). Similarly, he stated that fuel substitution in the core market was unlikely to occur without ample warning to WKP (T. 848). In addition, he indicated that the fact that WKP purchased some of its power rather than generating all of it meant that it could modify its generation in response to demand changes, which he characterized as a positive development (T. 852). Finally, Dr. Waters indicated that the supply uncertainties faced by WKP were primarily related to the cost of supply, not the existence of supply (Exhibit 39, page 64). He stated that the issue of what supply would be utilized was not important to investors as long as costs were passed through in rates (Exhibit 39, page 65).

As a result, Dr. Waters stated that he believed a common equity ratio of 35 percent (based on a capital structure inclusive of deferred taxes) was appropriate for WKP (Exhibit 39, page 66). He suggested that, for the purposes of setting rates, the excess equity be treated as ten year debt at a cost rate of 8.0 percent, and that no tax allowance for the excess equity be included in the revenue requirement. While rejecting the entirety of Dr. Waters' proposal, WKP indicated that it would finance long-lived utility assets with 20-year debt, which Dr. Waters indicated would cost approximately 8.75 percent (Exhibit 37, Question 5).

Based on his assessment of risk, Dr. Waters indicated that the required rate of return on equity for WKP was 10.25 to 10.75 percent versus 10.0 to 10.5 percent for a low risk, high grade utility. Dr. Waters stated that his ROE recommendation when combined with his capital structure recommendations would result in WKP's interest coverage ratios falling below 2.5 times. Nonetheless, he stated that he believed WKP's debt would still be regarded as a high quality investment by institutional investors (Exhibit 39, page 68).

3.1.3 Position of CAC(BC) et al

Drs. Berkowitz and Booth indicated that they placed WKP at the upper end of the utility risk spectrum due to its small size, the relatively small portion of internally generated power and the need to make some resource option decisions in the near term (T. 1183). Of these risks, they indicated that WKP's most significant risk was its resource acquisition risk and suggested a preference to see it move to a situation more akin to a gas distribution utility (T. 1185).

In addition to the qualitative assessment, the witnesses attempted to infer a beta estimate for WKP using an instrumental variables model. The model, which uses total asset growth and the debt/equity ratio, indicated that WKP had an inferred beta of 0.51. Based on both the qualitative assessment and the instrumental variables model, they indicated that the appropriate ROE for WKP would be 10.8 percent.

Drs. Berkowitz and Booth supported a 35 percent common equity component for WKP. They indicated that this equity component would place it at the low end of the range for electric utilities, but noted that WKP's capital structure contained approximately 6 percent in deferred taxes (Exhibit 47A, page 14-15). As did Dr. Waters, they recognized that this equity level, when coupled with their ROE recommendation, would lead to a decline in WKP's interest coverage ratios. In addition, they supported the proposal made by Dr. Waters with respect to the treatment of the excess equity (T. 1186-87).

3.1.4 Position of Kootenay-Okanagan Electric Consumers Association

The Electric Consumers Association ("ECA") supported the Commission's June 9, 1993 Decision with respect to WKP's capital structure and urged the Commission to deny WKP's request for a different capital structure (T. 1859). They noted that a 38 percent common equity component was not outside the range of common equity components enjoyed by other electrical utilities. Further, they disagreed that such a common equity component would prevent WKP from issuing new debt (T. 1861).

3.1.5 Commission Determinations

The Commission finds that the evidence before it does not warrant a reconsideration of its June 9, 1993 Decision with respect to the appropriate capital structure for WKP. Therefore, the Commission directs that for the purposes of determining rates, WKP is deemed to have a common equity component at year-end 1994 of 38 percent and at year-end 1995 of 35 percent. The Commission understands that these translate into mid-year common equity components of 39.0 percent and 36.5 percent, respectively. For the purposes of establishing rates for 1994, the excess equity will be treated as debt and assigned a cost of 8.75 percent as a proxy for the cost of long-term debt. For 1995, the cost assigned to the excess equity, if any, will be varied to reflect the change in the Commission's forecast yield on long-term Canada bonds for 1995 vis-a-vis the forecast for 1994.

The Commission recognizes that a thicker equity component, all else being equal, translates into higher interest coverage ratios and a greater ability to meet any trust covenants, which, in turn, may lead to easier access to capital markets. These are benefits not to be dismissed lightly since they may translate into lower capital costs to the utility and resulting lower rates to customers. Nonetheless, the Commission is also aware that these potential benefits must be weighed against the certain costs imposed by increased equity, both in terms of direct costs and in terms of tax implications.

In the specific circumstances of WKP, the Commission recognizes that the lower common equity component of capital structure will lead to a reduction in its times interest coverage. However, the evidence before this Commission is that ratios in both years will remain in excess of 2.0 times. While it is likely that the actual interest coverage ratios may be slightly below the trust covenant restriction of 2.25 times, the Commission is aware that this restriction is more onerous than that enjoined on many utilities and was imposed at a time when WKP's common equity component was significantly lower than that contemplated by the 1993 Commission Decision (T. 582). As a result, the Commission believes this will not unduly restrict WKP's access to capital markets.

With respect to the appropriate rate of return on equity, the Commission notes comments that the risks faced by WKP are somewhat more akin to those faced by a distribution utility than to a utility which generates most if not all of its own power. At the same time, the Commission agrees with Dr. Evans that the relatively small size of WKP limits its financial strength (Exhibit 11A, page 18) and imposes restrictions on its ability to access capital markets. Further, the Commission agrees with Dr. Evans that the appropriate ROE for WKP, inclusive of an appropriate flotation cost, must be determined on a stand alone basis. **As a result, the Commission finds that the appropriate rate of return on equity for WKP is 11.0 percent in 1994. For 1995, the appropriate rate of return on equity is determined as outlined in Chapter 4 of this Decision.**

3.2 Capital Structure and Return on Equity of BC Gas

3.2.1 Position of BC Gas

BC Gas has applied for a rate of return on common equity of 12.25 percent on a common equity component of 33.0 percent for the year 1994. For 1995, the utility has asked that the ROE be adjusted in accord with a mechanism discussed in Chapter 4 of this Decision.

Dr. Sherwin and Ms. McShane testified as to the business and financial risks to which BC Gas was subject. The witnesses stated that BC Gas' business risks fell within the areas of market demand risk, supply and deliverability risk, cost recovery risk, by-pass risk and regulatory risk (Exhibit 17, Tab 4, page 11). With respect to market demand risks, they stated that BC Gas had a relatively favourable customer mix with approximately 30 percent of deliveries made to the residential class and 21.2 percent made to the commercial class (Exhibit 17, Tab 4, page 15); however, these customer classes tend to be weather sensitive. In addition, nearly 25 percent of the lower Mainland industrial load was taken by institutional customers which also tended to be weather sensitive (Exhibit 17, Tab 4, page 16). BC Gas indicated that volatility in revenue due to weather had been recognized by the Commission in its 1992 Decision and that the change to seasonal rates since that Decision had increased the magnitude of the weather winter impact (Exhibit 59, Tab 19, page 5). Dr. Sherwin and Ms. McShane also identified risks attributable to the industrial sector which they described as resource oriented and subject to considerable cyclical volatility. Although industrial volumes in the Inland Division service area tended to be covered by demand charges, the industrial volumes in the Lower Mainland tended to be interruptible. Overall, they stated that they viewed BC Gas' market demand risks as being somewhat greater than the least risky Canadian gas distribution utility (Exhibit 17, Tab 4, page 16).

With respect to gas supply and deliverability risks, the witnesses noted such factors as the increase in competition within the gas industry, the fact that most of BC Gas' supply depends on a few Westcoast plants, and the lack of adequate storage or peak shaving facilities (Exhibit 17, page 4, page 19-20). In addition, Dr. Sherwin and Ms. McShane noted that the majority of BC Gas' base load supply contracts contained demand charges. Although they recognized the existence and benefit of the Gas Cost Reconciliation Account, they indicated that it did not reduce the fundamental longer term supply risks to the level of a low risk, high grade utility (Exhibit 17, Tab 4, page 22).

In assessing the risks of cost recovery and by-pass, the witnesses recognized the benefits of a number of deferral accounts to mitigate cost risks and the existence of the Commission's by-pass policy but did not consider that these policies reduced risks over the long-term. Finally, with respect to regulatory risks, the witnesses indicated that they were concerned with certain recent trends in regulatory awards that appeared to reflect demands that utility returns be reduced in times of prolonged recession in order to "share the misery" (Exhibit 17, Tab 4, page 24).

Dr. Sherwin and Ms. McShane stated that there were two inter-related aspects to financial risks: the degree of leveraged financing in the capital structure, and the degree to which regulatory return awards permitted a utility to maintain financing flexibility. With respect to BC Gas, the witnesses stated that the optimal structure would contain a 35 percent common equity ratio. Based on the most recently approved regulatory awards, the applied for 33 percent common equity component was shown to be approximately 5.5 percentage points lower than the median figure for 29 gas, electric and telephone utilities which ranged from 25.0 to 60.26 percent. The range for gas distribution utilities was 29.0 to 40.96 percent (Exhibit 17, Tab 5, Schedule 1). The witnesses agreed that there was a somewhat tenuous relationship between equity levels, interest coverage ratios and bond ratings although this did not suggest the impact of interest coverage ratios on bond ratings could be disregarded (T. 1489 and 1491).

The witnesses noted that BC Gas indenture provisions contained a 2.0 times interest coverage new issue test. Based on the application, the interest coverage ratio on the utility rate base would be 2.3 times and 2.0 times for the corporate BC Gas Utility. The difference reflects the impact of the Lower Mainland acquisition premium (Exhibit 17, Tab 4, page 30). Ms. Lambert, Vice-President/Treasurer of BC Gas indicated that a 25 basis point increase in the ROE leads to a 0.025 times increase in the interest coverage ratio (T. 1393).

To offset some of these risks, particularly those associated with weather, BC Gas has applied for a Revenue Stabilization Adjustment Mechanism. The mechanism will allow BC Gas to recover any over or under collection of the delivery margin (excluding basic charges) on sales to residential and commercial customers for the months of November through March, subject to a 5 percent plus or minus deadband on the customer use rate (Exhibit 59, Tab 19, page 17). BC Gas stated that an RSAM could be designed to remove any amount of annual revenue risk. The utility indicated that the RSAM (5 percent) proposal would stabilize the earnings of BC Gas to the point where its volatility of earnings would be comparable to industry norms for a distribution utility without seasonal rates. BC Gas stated that to more fully protect the utility from risks through a mechanism such as full decoupling or an RSAM with a 0 percent deadband would act to impose those same risks on customers through more frequent and larger adjustments in rates (Exhibit 59, Tab 19, page 6).

Dr. Sherwin stated that the position of BC Gas with respect to RSAM (5 percent) was "take it or leave it" (T. 1414) and that an RSAM (0 percent) was viewed as unacceptable (T. 1421). He indicated that investors would react negatively to either an RSAM (0 percent) mechanism or full decoupling. Dr. Sherwin used his experience to draw the conclusion that investors believe that there is an upside reward potential that would be eliminated with these options. He stated:

> "Because the weather is also related to the customer use and that, the two combined, are related to opportunities for achieving higher than allowed returns as well as incurring the risk of having less than the allowed returns." (T. 1417)

Although Dr. Sherwin strongly held the view that investors perceive an upside potential on taking weather risk, he equally strongly resisted any inference that utilities might "game" the determination of customer use per account statistics. He stated:

> "No utility to my knowledge would be so foolish as to deliberately underestimate when much is at stake, because the price of what -- I know you didn't say it but what you are implying of manipulation of customer use figure would come to haunt them in the next case. It goes to the credibility of management; it goes to the credibility of the professional people that work on this, and I don't think anybody would deliberately do it, at least not utilities in this country that I've been associated with." (T. 1422)

Dr. Sherwin and Ms. McShane indicated that their ROE recommendation was based on the Commission's acceptance of the RSAM (5 percent) proposal. Commission counsel queried Dr. Sherwin about the impact that retention of the status quo, i.e. no RSAM, would have on his recommendations with respect to the appropriate ROE for BC Gas. He responded that the status quo, with or without seasonal rates, would result in a requested increase in ROE of 40 to 50 basis points (T. 1471-1473). He stated that investors would not be significantly influenced by the seasonal rate structure and commended the Commission for implementing the 1993 Rate Design Decision. In addition, Dr. Sherwin and Ms McShane stated that in the absence of the revenue stabilization mechanisms, a higher common equity ratio would be needed for BC Gas to achieve an adequate degree of financing flexibility.

In addition to its applications with respect to ROE and capital structure, BC Gas applied to change the approved unfunded debt rate from 6.0 percent to 5.0 percent effective January 1, 1994 and to accrue any variations between the approved unfunded debt interest rate and the actual rate in a deferral account. As well, BC Gas applied to create a deferral account effective January 1, 1994 to record; (i) the difference between the forecast long-term rate of 8.0 percent (effective cost of 8.14 percent) and the effective rate achieved upon financing, and (ii) the difference between the forecasted principal and timing of the issue and that actually achieved upon financing. BC Gas proposed to amortized these amounts over two years commencing January 1, 1996.

3.2.2 Position of Wholesale Customers

In order to assess the risks to which BC Gas is subject, Dr. Waters stated that he examined previous Commission decisions related to BC Gas, bond rating reports, other investment industry reports, the utility's Annual Report and a document entitled Annual Insights 1993 also produced by the utility (T. 1547). Dr. Waters stated that in the BC Gas 1992 Annual Report, the utility indicated several business risks all of which could be divided into three categories: risks with respect to the predictability of year-over-year income; risks with respect to the fairness of the allowed level of rates; and risks respecting the long-term profitability of BC Gas (Exhibit 39, page 36).

Dr. Waters identified three items which act to reduce the risks associated with the predictability of income. These were the introduction of a mechanism to shelter BC Gas' income from the effects of weather (i.e. the RSAM); the introduction of a mechanism to reduce BC Gas' exposure to under recovery of demand charges [i.e. the Gas Cost Reconciliation Account ("GCRA")]; and the introduction of a deferral account for differences between projected actual unfunded and funded debt costs (Exhibit 39, page 36).

With respect to the fairness of the allowed level of rates, the witness indicated that investors had not seen the Commission's 1992 Decision with respect to BC Gas as being unfair. In support of this position, he noted that the "A" bond ratings for the long-term securities of BC Gas were confirmed after the 1992 Decision and that the market to book ratio for BC Gas Inc., of which BC Gas is the largest component, stayed above 1.0 (Exhibit 39, pages 40-41). Dr. Waters agreed that subsequent to the Decision the share price of the utility had fallen vis-a-vis the TSE Utilities Index, the Gas and Electric Utilities Sub-index and the 300 Index (Exhibit 63) but noted that the Decision had been comprehensive and dealt with a number of uncertainties which would have influenced investor expectations (T. 1532-1534).

With respect to the long-term demand for the services offered by BC Gas, Dr. Waters indicated that the information provided in BC Gas' Annual Insight 1993 publication indicated that the long-term profitability of the utility appeared bright (Exhibit 39, page 38).

As a result, Dr. Waters indicated that the 33.0 percent common equity component contained in the application was reasonable and should be combined with a rate of return on common equity of 10.0 to

10.5 percent. If this were adopted, he indicated that it would give rise to an interest coverage ratio of approximately 2.0 times (Exhibit 39, page 45). The witness indicated that in making this recommendation he had regard to BC Gas' capital expenditure plans and that in the absence of these plans his recommended ROE would have been less (T. 1566).

Similarly, Dr. Waters indicated that his return recommendation assumed the approval of the RSAM (5 percent). In response to a questions as to the impact the RSAM (5 percent) proposal should have on the appropriate rate of return on equity, Dr. Waters stated that in a world of simply random events which were subject to no bias in forecasting, but only uncertainty as to the actual outcome, the proposal would have little effect on the return to shareholders. As a result, he suggested that the most significant contribution of the RSAM might be to minimize short-term revenue shortfalls that make it difficult for the utility to issue additional debt (T. 1556-1557). In addition, he indicated that he did not think the RSAM would result in a large reduction in the required rate of return because he believed that the bulk of the risk premium that an investor in a utility required was for the long term uncertainties associated with the investment (T. 1558). Nonetheless, he indicated that if the deadbands were removed so that the possibility of earning the allowed return became more certain, it would have the effect of shifting his return recommendation from the mid-point to the low point of his recommended range (T. 1559) since investors would be subject to less exposure than if it were not the case (T. 1560).

Consumers Packaging Inc., Crestbrook Forest Industries Ltd., Elkview Coal Corporation, Fording Coal Ltd. and Hiram Walker & Sons Limited ("the Gas User Group") supported these views (T. 1877).

3.2.3 The Position of CAC(BC) et al

Drs. Berkowitz and Booth indicated that the major risks facing a natural gas distribution utility stem from the loss of customers through the possibility of direct purchases, combined with the installation of a private distribution system, and the need to forecast demand (Exhibit 47B, page 3). If volumes are lost through by-pass of the utility's system or demand fails to materialize as forecast for some other reason, the utility will be unable to recover all operating and financing costs and will be prevented from earning its allowed rate of return on equity. The witnesses indicated that by-pass risk had been eliminated for BC Gas through the introduction of by-pass rates (Exhibit 47B, page 3).

Although the vagaries of weather meant annual demand forecasts were subject to uncertainty, they indicated that investors understood that weather risk was random and that it could be diversified away by including the utility stock in a portfolio of shares (Exhibit 47B, page 4). As a result, Drs. Berkowitz and Booth indicated that weather risk should have no impact on investors' assessments of the riskiness of the firm (T. 1169).

Because of their view that investors could diversify away the weather related risk in a balanced portfolio of stocks, the witnesses held the view that the RSAM should not lead to an adjustment to the ROE, although they indicated that a minor benefit of RSAM with a narrow deadband would be to remove any "subtle biases" in forecasting customer consumption. The witnesses qualified their position to state that a utility could face financing problems if several successive warm winters resulted in depressed earnings. Further, they stated that full decoupling, which affects more than weather-related risks, would decrease the risks of the utility and should lead to a decline in the appropriate ROE (T. 1172-1173).

Overall, the witnesses stated that BC Gas ranks as one of the largest Canadian gas distributors and that this would cause it to be seen as one of the least risky gas distributors.

As with WKP, Drs. Berkowitz and Booth also used the instrumental variables model to infer a beta value for BC Gas. Using data from the utility's 1993 draft financial statements they indicated that the inferred beta was 0.44. The witnesses deemed it more appropriate to infer a value rather than use actual historical values because of the recent corporate re-organization of BC Gas. However, the witnesses assessment of BC Gas was that it was a below average risk utility and therefore a beta estimate of 0.425, the actual 1992 beta value, was recommended.

Based on the above, the witnesses recommended that BC Gas be allowed a rate of return on equity of 10.4 percent, some 10 basis points less than for the benchmark set of utilities. The witnesses accepted the 33.0 percent common equity component for BC Gas.

3.2.4 Commission Determinations

In this Decision the Commission must consider the extent to which the proposed Revenue Stabilization Adjustment Mechanism ("RSAM") and other mechanisms increase or decrease the appropriate return on equity ("ROE") for BC Gas. This Panel recognizes that the final determination regarding implementation of a weather stabilization factor, RSAM at any level of deadband, or full decoupling will be considered by the panel hearing the 1994/95 Revenue Requirement Application of BC Gas. The final determination of BC Gas' RSAM proposal, in response to the directions given to it in the Commission's 1992 Revenue Requirement Decision, will reflect not only the impact of various revenue stabilization mechanisms on the appropriate ROE of the utility, but the other impacts resulting from a review of sales forecast volatility, support for conservation measures and potential revisions to O&M and capital forecasts due to weather. This Decision can contribute to the final determination by indicating the range of impacts that various measures would have on the appropriate risk and ROE of BC Gas.

The range of options that can be considered with respect to revenue stabilization include the following four alternatives:

- Status Quo - The existing rate structure, including seasonal rates for residential customers, could be maintained. In this option the impacts of colder or warmer than normal weather on sales volumes would flow directly to the bottom line of utility earnings. The impact would be partly offset by the existence of the GCRA that currently exists for BC Gas.

- RSAM (5 percent) - The BC Gas proposal is to implement a revenue stabilization adjustment mechanism with a deadband zone so that revenues above or below expected revenues by up to 5 percent would be absorbed by the Company. The utility would be sheltered from the impacts of extremely warm weather years like 1992 and the customers would receive a return of excess margin revenue in extremely cold years.

  The RSAM proposals apply only to residential and commercial rates for the five winter months. BC Gas believes that industrial rates can be estimated with a higher level of accuracy and it is recognized that the margins from industrial sales are low by comparison with residential margins. New customer additions would also be excluded from RSAM calculations.

- RSAM (0 percent) - The 0 percent deadband results in an effective decoupling of residential and commercial sales during the five winter months. Industrial sales and the sales to all customers in the other seven months would remain unaffected.

- Decoupling - This option protects the utility completely from variations in actual sales vis-a-vis forecast sales for all classes of customers, whether the fluctuations are related to weather, demand side management initiatives, or any factor.

With respect to the impact that the RSAM (5 percent) proposal could have on the utility's cost of equity capital, the Commission is perplexed by the dual argument of Dr. Sherwin that investors perceive an upside potential with respect to the existing rate setting methods, whereby normalized utility sales forecasts are embedded in the rates, but that utilities in Canada have not "gamed" or otherwise manipulated sales forecasts or expenditures to improve utility earnings (T. 1417, 1422). For Dr. Sherwin's argument to be valid investors must have erred by expecting a manipulation that does not occur. If, however, there is an upside potential in the existing rate making methodology due to either an inherent bias in the forecasting methods or utility management of customer services in warm weather years to offset the downside earnings risk, this would provide a substantial argument in favour of decoupling. These matters will be pursued further in the upcoming revenue requirement hearing.

The Commission generally agrees with the views expressed by Drs. Waters, Booth and Berkowitz that depressed earnings over several consecutive warm years could potentially make it difficult for a utility to issue additional debt. Equally, the Commission recognizes that if a revenue stabilization mechanism is implemented there is the possibility that the accumulation of large deferral accounts in favour of the utility shareholders might develop over a number of warm years. It is possible that investors could develop a negative view towards those deferral accounts if they thought that the full recovery of the deferral accounts was subject to risk. However, there is no evidence to support a supposition that investors would have this view, given the regulatory treatment that has existed over time by this tribunal and by other tribunals in Canada. The Commission notes that there was a lack of empirical or factual data presented at this hearing since the revenue stabilization mechanisms are relatively new in Canada. The Commission, therefore, had to rely on speculative views of the witnesses based on their review of investor sentiments and the experiences that have occurred in the United States.

At this stage the Commission holds the view that there is very little difference in risk for the utility based upon the status quo (with or without seasonal rates) or with the RSAM (5 percent) option. The return on equity established for BC Gas in this Decision would be appropriate for each of these options.

The Commission also believes that the reduced level of revenue volatility resulting from the RSAM (0 percent) and decoupling options are similar in their impact on utility risk and appropriate ROE. The Commission believes that were either of these two options to be implemented the reduction in ROE would be very modest. Therefore, if either of these two revenue stabilization mechanisms are implemented as a result of the revenue requirement hearing decision, the appropriate ROE for BC Gas should be reduced by 10 basis points.

With the exceptions of Drs. Berkowitz and Booth, who saw BC Gas as slightly less risky than their set of benchmark utilities, the experts agreed that BC Gas was generally of comparable risk to low risk, high grade utilities. The Commission concurs with this assessment. **Therefore, if the Panel of the Commission charged with determining the desirability of the RSAM proposal accepts the proposal as put forward by the utility or rejects the proposal completely, this Panel of the Commission finds that the appropriate rate of return on common equity for 1994 is 10.75 percent. If RSAM (0 percent) or full decoupling is determined to be appropriate, this Panel finds that the appropriate rate of return on equity should be reduced by 10 basis points. For 1995, the appropriate rate of return on equity is determined as outlined in Chapter 4 of this Decision.**

The Commission has seen no evidence to change the judgment contained in the 1992 Decision that 33 percent is an appropriate common equity component for BC Gas.

The Commission approves the use of a 5.0 percent unfunded debt rate for use with the short-term debt deferral account. In addition, the Commission approves the long-term debt deferral account as set out in the Application.

3.3 Pacific Northern Gas

3.3.1 Position of the Applicant

In 1994, PNG is expected to deliver 90.2 percent of its throughput to industrial customers. Of the total industrial volumes, 73 percent are expected to be delivered to Methanex, with a further 21 percent delivered to three additional customers. Ms. McShane indicated that the concentration of load in the industrial sector as well as the size of the company were the key elements of business risk facing PNG (T. 1215). In particular, she noted that there was substantial uncertainty associated with the outlook for the key customers served by PNG. For example, the witness indicated that the outlook for Methanex, although brightened by the U.S. Clean Air Act amendments, which were expected to increase demand for methanol as a feedstock, was limited by the existence of substitutes. In addition, the outlook for pulp and paper plants was largely cyclical and would depend on the state of the world economy and the value of the Canadian dollar (Exhibit 28, page 12). Nonetheless, she noted that the risks associated with this high concentration of sales were offset, in part, through a guarantee by the British Columbia Government on 60 percent of the volumes taken by Methanex and through minimum bill provisions contained in industrial contracts. As a result, the company calculated the amount of the requested equity return at risk during 1994 at 7.0 percent based on margin recoverable from volumes above minimum bill levels and interruptible volumes (Exhibit 27, Tab 1, page 9). This is somewhat less than the 7.7 percent exposure calculated in 1992, but greater than the 4.5 and 2.0 percent at risk from industrial customer margins calculated for Centra Ontario and Consumers Gas (Exhibit 28, page 12).

Ms. McShane testified that PNG also faced gas supply and deliverability risks and regulatory risks (Exhibit 28, page 7). The terrain traversed by its transmission system is more rugged than that of other utilities so that the line is subject to greater risk of breakage. Although PNG has business interruption insurance, it contains a relatively high deductible amount. Further, concerns were expressed that if claims continued to be made, the insurance might be withdrawn in the future (T. 1236-38). In addition, PNG now contracts for its gas rather than relying on the pooled reserves of CanWest, leading to a somewhat greater risk of deliverability failure (Exhibit 28, page 13). The new contracts contain producer demand charges for which PNG is at risk if actual volumes fall short of forecast. Similarly, PNG is at risk for Westcoast capacity tolls (Exhibit 28. page 14).

Based on these factors, Ms. McShane concluded that PNG's business risks are greater than that of any of the major Canadian gas distributors (Exhibit 28, page 15).

Ms. McShane assessed PNG's capital structure and interest coverage ratios to determine its financial risk in comparison to other utilities. She noted that the portion of debt included in the capital structure had risen since 1992 while the portion of common equity had decreased (Exhibit 28, page 16). Further, she noted that the expected debt component for 1994 was approximately 9 percentage points greater and the common equity component 3 percentage points less than the median values calculated for major Canadian utilities (all values exclusive of deferred taxes) (Exhibit 28, Schedule 1).

With respect to interest coverage ratios, Ms. McShane indicated that her recommendation would result in a 2.20 times ratio. This would be sufficient to allow the utility to maintain its B++ rating but fell below the 2.5 times guideline for an A rating. Ms. McShane stated that given PNG's size, capital expenditure plan and external financing needs, it would be unlikely that it would attempt to achieve the higher credit rating (T. 1242). As a result, Ms. McShane indicated that PNG's financial risks had increased since the last hearing and were higher than that of the average Canadian electric/gas utility (Exhibit 28, page 17).

Using a DCF methodology, Ms. McShane compared the historic cost of equity capital for five high grade utilities, 11 non-diversified utilities and three medium grade utilities for the period 1984 to 1992. This suggested that the spread between a high grade utility and a utility similar to PNG was 1.4 percentage points. In addition, Ms. McShane examined the spread between the cost of debt for utilities with an A bond rating and those with a B++ bond rating and found it to be 50 basis points. Based on these two analyses, Ms. McShane determined the appropriate incremental premium for PNG was 75-100 basis points.

3.3.2 Position of Wholesale Customers

Dr. Waters noted the evidence provided by PNG showing that its rate of return on common equity could fall short of its applied for rate of return by 7.0 percentage points but indicated that, since 1984, PNG had, on average, achieved its allowed rate of return, which he suggested would be a source of comfort to investors (Exhibit 39, page 51).

Dr. Waters reviewed the short-term business risks facing PNG and did not appear to find them onerous. He indicated that unanticipated operating costs were unlikely to adversely affect the allowed ROE since most of PNG's costs were likely to vary only within a narrow range and the Commission had shown itself sympathetic to unplanned maintenance expenses (Exhibit 39, page 52). Similarly, he indicated that the impact of prolonged physical outages would be likely offset through business interruption insurance and the possible amortization of any revenue shortfall in future rates. Finally, he noted that the Commission had allowed PNG a deferral account in which to accrue any differences between actual and forecast short-term debt and that this account reduced financing risk (Exhibit 39, pages 53-54).

As a result, he concluded that the only major risk facing PNG was a permanent impairment of earning power arising from PNG's heavy reliance on industrial load, and in particular Methanex. He indicated that these risks are mitigated by the contractual relationships between PNG and the British Columbia Government and the firm transportation service agreement which exist between the parties.

Dr. Waters indicated that he found the applied for capital structure reasonable (Exhibit 39, page 57) and recommended that PNG be awarded a rate of return of 10.75 to 11.25 percent on the common equity component (Exhibit 39, page 58). He estimated that this would result in an interest coverage ratio of 1.94 to 1.99 times compared with the 2.20 times which would result if PNG's application were approved. Dr. Waters stated that his recommended rate of return would be sufficient to allow PNG to maintain its financial integrity (Exhibit 39, page 61).

3.3.3 Position of CAC(BC) et al

The witnesses noted the concentrated industrial base of PNG's customer mix (Exhibit 47B, page 5) and in particular the reliance on four industrial customers. However, they suggested that these risks are offset by an outlook for Methanex which they characterized as bright (Exhibit 47B, page 5) and the existence of the government guarantee. They also noted that PNG has a diversified gas supply portfolio.

As with BC Gas and WKP, Drs. Berkowitz and Booth calculated an inferred beta for PNG which they found to be 0.48. However, they recommended the use of a 0.525 beta. Based on the above, they recommended an allowed rate of return on equity of 10.8 percent, or 40 basis points more than they recommended for BC Gas. They indicated that the 10.8 percent equity return would give rise to an interest coverage ratio of 2.0 times.

3.3.4 Commission Determinations

The Commission accepts the capital structure put forward by PNG in its application as constituting a reasonable basis on which to determine rates.

The Commission recognizes the risks imposed upon PNG by the high concentration of industrial sales; however, it believes the short-term impacts of these risks to be significantly mitigated through the government guarantees, the use of minimum bill provisions, and the existence of a deferral account associated with interruptible sales. Similarly, the Commission believes that several of the other short term risks are mitigated through such provisions as business interruption insurance. The Commission finds that the major risk facing the shareholders of PNG is the risk of permanent impairment through the loss of one or more of the industrial customers.

Although the witnesses had varying assessments of the riskiness of PNG, the Commission notes that no witnesses indicated that the incremental premium for PNG, relative to the set of low risk, high grade utilities, should be in excess of 75 to 100 basis points. **The Commission finds that the appropriate rate of return on common equity for PNG is 11.5 percent. The appropriate rate of return on common equity for 1995 is determined as outlined in Chapter 4 of this Decision.**

3.4 Centra Gas - Fort St. John District

In a Decision dated March 11, 1994, the Commission accepted the proposal that the appropriate ROE to be allowed Centra-FSJ would be the simple arithmetic average of the ROEs allowed PNG and BC Gas. **Based on the determinations contained in this Decision with respect to those utilities, the Commission finds that the appropriate ROE for Centra-FSJ is 11.125. This assumes that the ROE for BC Gas is 10.75 percent. Should the actual return awarded BC Gas be lower due to the impact of RSAM (0 percent) or full decoupling, the ROE for Centra-FSJ will not be changed. The appropriate rate of return on common equity for 1995 is determined as outlined in Chapter 4 of this Decision.**

4.0 RETURN ON EQUITY ADJUSTMENT MECHANISM

4.1 BC Gas and PNG Proposal

In their evidence with respect to BC Gas, Dr. Sherwin and Ms. McShane proposed that the rate of return on equity for 1995 be set by use of a formula which would adjust the 1994 award to account for changes in capital market conditions. In particular, they suggested that a return on equity adjustment mechanism be adopted that would: (i) be based on a well-accepted and understood methodology for estimating the cost of equity for a regulated utility; (ii) track changes in the cost of equity; (iii) be based on objectively determined relationships between cost of equity and cost elements directly observable, such as interest rates or dividend yields; (iv) be based on a methodology that contains a significant component of the cost of equity which is directly observable; and (v) be consistent with the forward test year approach (Exhibit 17, Tab 4, page 42). They suggested that the methodology which best met these criteria was the equity risk premium method. BC Gas' proposal was supported by PNG.

Dr. Sherwin and Ms. McShane envisioned a formula which would work as follows. First, when the Commission issued its decision with respect to the allowed return, it would explicitly specify the expected long-term Canada bond (30-year) yield upon which the allowed return was premised. Second, the Commission would obtain from the November Consensus Forecast (Consensus Economics, London, England), issued just prior to the year for which the ROE was to be adjusted, the yields on 10-year Canada bonds projected 3 and 12 months hence. The average of the two point estimates would serve as a proxy for the forecast yield on 10-year Canada bonds for the upcoming year. Third, the 10-year yield would be adjusted to reflect the spread between 10- and 30-year bonds based on a six day period encompassing the end of November (Exhibit 19, Tab 44). In times of capital market volatility, Dr. Sherwin suggested that the experts which had appeared before the Commission at the time of the initial ROE determination was made be asked for their opinion as to the appropriate time period to use to calculate the spread (T. 474). Fourth, the 1995 forecast of long-term Canada bond yields would be subtracted from the 1994 forecast as specified in the Decision. Fifth, based on the difference in forecast long-term Canada bond yields, the 1994 ROE would be adjusted based upon an assumed inverse relationship between interest rates and equity risk premiums. Specifically, if the forecast yield had increased (decreased) by 1 percentage point, the allowed ROE would increase (decrease) by 50 basis points (Exhibit 17, pages 45 and 46).

In support of the proposed inverse relationship between interest rates and the equity risk premium, the witnesses cited a study they had undertaken which measured the difference between the annual cost of equity for five high grade utilities, measured via a DCF approach and the yield on long-term Canada bonds for the period 1976 - 1993 (Exhibit 17, page A-4). The study estimated the cost of capital as the sum of the quarterly dividend yield adjusted for growth and a weighted average of achieved five and ten year dividend growth rates and retained earnings growth. Seven different weighting scenarios were employed to give a range of expectations with respect to growth.

The witnesses stated that the data indicated an inverse relationship between interest rates and risk premiums such that when interest rates were above 12 percent the risk premium was 1.1 percent while when interest rates were below 9 percent the risk premium was 4.4 percent (Exhibit 18, page A-5). The witnesses attributed the decline in risk premiums to a decline in investor perception of utility risk due to the introduction of the forward test year, a downward bias in recent calculated growth rates in dividends due to declining trends in allowed returns, and a tendency towards a narrowing of the risk premium in the contraction phase of the business cycle (Exhibit 18, page A-6).

In addition, the witnesses regressed the risk premiums implicit in the allowed ROE for the five high grade utilities against the long-term Canada bond yields for the period 1979 to 1993 and found that the ROE declined (rose) 47 basis points for every percentage point decline (rise) in long-term Canada bonds. When data for interest rates level above 12 percent were excluded, the postulated relationship was shown to be weaker (Exhibit 69).

The witnesses suggested that no change be made to the allowed ROE if the change in the forecast of long-term Canada bond yields was less than 50 basis points. Further, they suggested that the formula should be constrained such that if the decline in interest rates was greater than 100 basis points or the rise in interest rates was greater than 200 basis points, the formula would be abandoned (Exhibit 17, page 47). The asymmetrical boundaries reflected a reluctance on the part of the witnesses to recommend their adjustment method for low levels of interest rates since they did not have data to test whether the inverse relationship was valid at these levels (T. 461). In addition, Ms. McShane indicated that a 200 basis point increase in one year's time signaled that something significant was occurring in the economy (T. 461).

In response to questions as to how the long the adjustment mechanism should apply, the witnesses indicated that the time period depended on the degree to which the risk profile of the utility had changed (Exhibit 34). In general, the witnesses suggested that the risk profile was unlikely to change substantially within two years but that the utility should have the right to seek a change in its ROE prior to that if it felt it was warranted. The witnesses suggested that the mechanism could extend as long as five years as long as there was a complaint mechanism (T. 475).

4.2 Position of WKP

Dr. Evans indicated that an automatic adjustment mechanism of the sort put forward by Dr. Sherwin and Ms. McShane was acceptable given certain limitations. He indicated that a reasonable approach would be one where the Commission set the ROE for a one-year future test period. If capital market conditions changed only modestly in the first year and were expected to be stable in the next year, then the ROE would be adjusted by use of a formula. If there were substantial changes in capital market conditions, he suggested a redetermination of the ROE would be appropriate after the first year (Exhibit 11B, page 2). Initially, Dr. Evans suggested that the mechanism should cover no more than a two-year time period, even if capital market conditions were stable, since the Commission would wish to re-assess non-capital market conditions that could affect the ROE for the utility (T. 198-199). However, in response to a question, he indicated that he would support an automatic adjustment period of up to five years if it were coupled with a complaint procedure.

Dr. Evans agreed that any automatic adjustment mechanism should reflect an inverse relationship between risk premiums and yields on long-term Canada bonds; however, he estimated that a 1 percentage point rise (decline) in long-term Canada bond yields would be associated with a 65-70 basis point rise (decline) in the ROE (T. 201) instead of the 50 basis point change put forward by Dr. Sherwin and Ms. McShane.

4.3 Position of Wholesale Customers

Dr. Waters accepted the basic proposal put forward by Dr. Sherwin and Ms. McShane that the adjustment mechanism be tied to changes in interest rates (T. 812) but suggested that, initially, any automatic adjustment mechanism should be for one year only followed by a short review to guard against the use of a benchmark value that was atypical (T. 680). He suggested that such a review would consider the expected economic and financial climate (T. 682).

Dr. Waters did not agree that the data indicated an inverse relationship between the risk premium and interest rates, particularly for interest rates below 10 or 12 percent (T. 682). He indicated that at past very high levels of inflation, interest rates incorporated a purchasing power risk premium which was not reflected in equity returns and that this led to the perception of an inverse relationship (T. 776-780). As a result, he indicated that the relationship between risk premiums and interest rates was unlikely to be linear since the purchasing power risk premium was unlikely to be incorporated in lower rates of interest. Accordingly, he suggested that as long as interest rates were below 10 percent, he would not vary the absolute amount of the risk premium (T. 804).

Dr. Waters did not believe that the premium should last for an indefinite period of time subject to a complaint provision, since he found that Intervenors were often fragmented and it was difficult to get them to act in concert to initiate a complaint (T. 683-84).

4.4 Position of CAC(BC) et al

Drs. Berkowitz and Booth accepted the basic proposal that the allowed ROE be varied in response to changes in long-term Canada bond yields. They agreed with Dr. Sherwin and Ms. McShane that there be no change in the allowed ROE if the change in long-term Canada bond yields was within 50 basis points of the initial projection upon which the ROE was determined (Exhibit 47A, page 33). Further, they suggested that the maximum period for which the automatic adjustment mechanism should apply was three years and that there should be a compliant provision which could trigger an earlier re-evaluation (T. 1075-1076).

Like Drs. Evans and Sherwin and Ms. McShane, Drs. Berkowitz and Booth suggested that an inverse relationship existed between long-term bond yields and the equity risk premium; however, they estimated the relationship to be substantially smaller. For every 1 percentage point rise (decline) in the long-term Canada bond yields, they estimated that the allowed ROE would rise (decline) by 80 to 90 basis points. The witnesses indicated that they did not consider their estimates to be statistically significant and did not place a great deal of faith in them (T. 1109-1110).

4.5 Commission Determinations

For the purpose of setting the 1995 rate of return on common equity for the Applicant utilities, including Centra-FSJ, the Commission accepts an automatic adjustment mechanism based on the principles put forward in the BC Gas application, with exceptions as specified below.

Specifically, the Commission has indicated that the forecast for 1994 long Canada yields on which it has based its Decision is 7.75 percent. The Commission will obtain from the November, 1994 Consensus Forecast (Consensus Economics, London, England) the yields on 10-year Government of Canada bonds projected 3 and 12 months hence. The average of the two point estimates will serve as a proxy for the forecast yield on 10-year Canada bonds for the upcoming year. To obtain an estimate of the yield on 30-year bonds, the Commission will calculate the spread between the yields on a benchmark 10-year and a benchmark 30-year Government of Canada bond based on the last six days of November for which there are estimates, as these appear in the Financial Post. Should the Commission decide that capital markets are too volatile to rely on these data, the Commission will ask for further submissions from all interested parties as to the appropriate spread between 10- and 30-year bonds. The 1995 forecast of long-term Canada bond yields will be subtracted from the 1994 forecast as specified

in this Decision. If the change in the forecast long-term Canada bond yield is less than 50 basis points, there will be no change in the allowed ROE. If the change in the forecast of long-term Canada bond yield is greater than 50 basis points, but the absolute forecast of the long-term Canada bond yield is less than 13.0 percent, the ROE will be adjusted on a one for one basis, rounded to the nearest 25 basis points. If the absolute forecast of the yield on long-term Canada bonds is greater than 13.0 percent, the Commission may require the utilities to submit new evidence as to the appropriate rate of return on common equity for a set of low risk, high grade utilities. The Commission rejects the proposal put forward by BC Gas that a decline in long-term Canada bond yields of more than 100 basis points or an increase of more than 200 basis points will result in the abandonment of the formula.

In making these determinations, the Commission has noted Exhibit 69 which indicates that the inverse relationship postulated by Dr. Sherwin, Ms. McShane and others appears to reflect the incorporation of a purchasing power risk premium in long-term Canada bond yields at times of high inflation. The Commission notes that expectations of high inflation have not been included in any of the forecasts of economic conditions submitted at this hearing and so does not believe reflection of an inverse relationship between interest rates and the equity risk premium in the formula is warranted at this time. The Commission is willing to hear further submissions on this matter in future hearings.

The Commission will monitor the fluctuations in long-term Canada bond yields, other market factors, and the general experience with the adjustment mechanism to assess its ongoing appropriateness. If the Commission judges the mechanism to have performed favourably, and capital market conditions so warrant, the Commission may choose to extend the automatic adjustment mechanism for a further one or two years after 1995. Utilities or other parties may complain at any time under Section 64 of the Act and the Commission will assess the merits of such complaints to determine if an ROE hearing is required.

5.0 FUTURE GENERIC ROE HEARINGS

5.1 Introduction

In a letter dated January 21, 1994, the Commission indicated that it wished to hear evidence on future processes or mechanisms that might be employed to improve the determination of rate of return on equity and capital structure issues in future years. In particular, the Commission identified the following questions on which it wished to hear submissions:

(i) should future joint hearings set the capital structure and rate of return on equity for individual utilities or should it be set for a phantom "low risk" utility only;

(ii) if the rate of return for the individual utilities are to be set, for what time period should the premium awarded each utility apply, i.e. should the premiums be determined annually or for a longer period of time;

(iii) if the premiums are to last for more than one year, how should the rate of return on the phantom utility be adjusted to reflect changes in the financial climate, i.e. changes to the long-term bond rate; and

(iv) when should the joint hearing on ROE and capital structures be held, eg. late fall of the preceding year?

5.2 Position of WKP

Dr. Evans stated that some rate of return issues were common to all utilities and could be handled in a generic hearing while other issues, such as the relative risk and appropriate capital structure, were unique to the specific utility under examination and lent themselves less well to a generic process. As a result, he recommended that, at a minimum, the Commission hold separate hearings on relative risk and capital structure issues (Exhibit 11B, page 3). Dr. Evans indicated that this could take place in either the individual company revenue requirement hearings or in a set of sequential hearings following a hearing that considered generic issues (Exhibit 11B). If the Commission decided to hold a generic hearing which also considered capital structure issues, Dr. Evans recommended that gas and electric utilities not be grouped together since the issues facing each were different (T. 195).

Although Dr. Evans accepted that certain issues could be handled generically, such as capital market conditions and application of rate of return tests (T. 184), he indicated that he was uncertain as to whether it was more efficient to do so in a single generic hearing (Exhibit 11B, page 2). In particular, he noted that generic hearings increased the number of participants vis-a-vis single utility hearings and that this led to an increase in the amount of cross-examination and the number of information requests (T. 184-185). In addition, he noted that it increased costs to Intervenors interested in only one utility since hearing time would be devoted to issues which were not relevant to them (T. 185). Finally, he suggested that two proceedings increased the time that management had to devote to the regulatory process (T. 667). Offsetting these costs, were benefits such as the participation of a greater number of expert witnesses at one time leading to a better balance of views (T. 186) and cost savings for Intervenors who would have appeared at more than one hearing (T. 191). Overall, he concluded that only experience will show where the balance lies between costs and benefits (T. 192).

Mr. Ash of WKP agreed with the benefits identified by Dr. Evans with respect to potential economies and a more complete record for the Commission, and identified a further potential benefit of consistency from each utility viewing the experience of the other participating utilities (T. 662). With respect to costs, Mr. Ash indicated that the current process had increased costs to WKP in that the utility had to hire legal counsel for two proceedings and that Dr. Evans' input had been greater than originally anticipated (T. 667); however, with experience Mr. Ash expressed hope that these costs would be reduced.

Mr. Ash stated that he had some concern about different panels hearing different parts of the utility's revenue requirement application. He suggested that one or two Commissioners should be common to each panel (T. 663) and that key issues should be brought out before both panels (T. 664). Mr. Ash stated that he assumed that the Commission talked amongst itself so that he did not see insurmountable problems from two panels (T. 665).

If the Commission were to continue with a generic hearing approach, Dr. Evans suggested that the hearing occur in the autumn preceding the test year so that a decision could be rendered in time for implementation by January 1 of the test year.

5.3 Position of BC Gas

Dr. Sherwin and Ms. McShane indicated that a generic rate of return hearing was an appropriate vehicle for streamlining the regulatory process and avoiding duplication but they believed it should be limited to a determination of the appropriate ROE for a benchmark set of utilities and a mechanism for future adjustments to the equity return. They indicated that they had difficulty envisioning how the determination of the risks of individual utilities relative to the benchmark utilities lent itself to a generic approach (Exhibit 34).

The witnesses identified a number of benefits from this approach. First, Dr. Sherwin suggested that management costs, for some utilities, could be reduced over time if the Commission adopted what he labelled a "seriatim" approach. He described a scenario in which one or two of the larger utilities participated actively in a generic proceeding which set the benchmark ROE, with small utilities accepting the outcome of this proceeding and focusing their attention on subsequent individual hearings where specific risk issues would be considered (T. 438-440). Second, he indicated consideration of the ROE in a generic hearing could encourage the settlement of other revenue requirement issues through an alternate dispute resolution ("ADR") procedure (T. 445). Alternatively, he suggested that ADR could be used to settle certain ROE issues, such as the capital market forecast and the market risk premium, outside of the hearing process (T. 444). This benefit was also discussed by Mr. Lloyd, Executive Vice President, Finance and Administration, BC Gas (T. 1375-1376). In a similar vein, Dr. Sherwin agreed that a generic process might act to keep a utility out of the hearing process for longer periods of time and that this could act to encourage innovation and cost efficiency because of the longer period in which excess profits would be earned by the utility (T. 511). Finally, Dr. Sherwin indicated that the costs to small Intervenors would be minimized since they could focus their attention on the individual hearings which dealt with specific utility risk issues (T. 433).

Mr. Lloyd indicated that an additional benefit of the generic process, when combined with Intervenor funding, was to allow the provision of expert witnesses, other than those hired by the utility, to fall upon Intervenors and not on Commission staff (T. 1374).

Dr. Sherwin and Ms. McShane concurred with Dr. Evans that a generic approach could add to the costs of the information request process. Dr. Sherwin indicated that there was increased risk of argumentative rather than factual interrogatories in a generic hearing, in part because there was a sense that the stakes were higher (T. 455-456). To offset these costs, he suggested that the Commission appoint a third party who could judge whether particular information requests were too onerous to be answered (T. 482). Mr. Lloyd noted that the current process had led to an increase in expert witness costs (T. 1376).

Dr. Sherwin rejected the idea that a single expert witness could be retained to act for all of the subject utilities since he was concerned that there might be conflicts between them as to the appropriate assessment of relative risk (T. 432). However Ms. McShane indicated that she had acted for numerous Canadian utilities and had not experienced any conflicts. In addition, she indicated that the use of only one witness would allow for the use of similar studies and consistent judgement (T. 498). Dr. Sherwin stated that one expert witness could act for all of the Intervenors since they would not have to be concerned with proprietary interests (T. 432).

Dr. Sherwin indicated that he was not uncomfortable with ROE evidence being heard by one panel of the Commission and the remaining revenue requirement evidence being heard by a separate panel as long as both were governed by the rules of natural justice, there was reasonable consistency between the two panels, and each panel recognized that the evidentiary presentations made to one had some bearing on the evaluation of evidentiary presentations made to the other (T. 484-485). He agreed that the expert witnesses would need to identify critical elements in the revenue requirement which affected their ROE estimate and to state how their estimate would change given alternative decisions (T. 489). In contrast, Mr. Lloyd indicated that he was concerned that aggrieved parties might use the fact that two panels had heard the evidence to attack good decisions, although he felt that the risk of this occurring was lessened if the generic hearing was confined to the setting of a benchmark ROE only (T. 1378-1379).

Mr. Kleven, Senior Vice-President, BC Gas indicated that he thought the risks of gas and electric utilities would become more distinct if competitive forces within each industry continued to grow and that this was an additional reason to keep the assessment of individual risk issues within utility specific hearings (T. 1377). If so, Mr. Lloyd suggested that it may become more difficult to combine gas and electric utilities even within a limited generic process (T. 1380).

5.4 Position of PNG

Mr. Dyce, President and Chief Executive Officer, PNG indicated that he favoured a single process which set both the benchmark ROE and the premium for the individual utilities. He suggested that the premium should be considered valid for three to four years unless a clear need for change could be demonstrated. In that case, he suggested an individual hearing could be held to reassess the premium but not the benchmark (T. 1252).

Mr. Dyce's support for a generic hearing was contingent on its results lasting for more than one year. If a generic hearing was held every year, he indicated that PNG would find the process too costly (T. 1249), in part because of the large number of parties involved, resulting information requests, etc.

Mr. Dyce stated that he was not troubled about the possibility of one panel hearing evidence with respect to the ROE and a second panel hearing evidence with respect to the remainder of the revenue requirement. He indicated that he saw them as two separate issues, the one dealing with cost of service and rate base issues while the other dealt with cost of capital (T. 1255).

5.5 Position of Wholesale Customers

Dr. Waters suggested that the generic hearing be limited to an assessment of the appropriate rate of return on equity for a group of low risk utilities (T. 678) and that the appropriate premium and capital structure for the individual utilities be assessed in the individual revenue requirement hearings. If this process were to be accepted, Dr. Waters indicated that he would see no difficulty in having a different panel for each of the phases (T. 795-796).

Dr. Waters indicated that a generic hearing approach could impose extra costs on small Intervenors (T. 790) but doubted that it added substantial additional costs to large Intervenors who could deal with extra evidence in an expeditious manner (T. 791). Further, in his own case, he believed the generic process had saved him time compared with appearing at three separate hearings (T. 789). Further, he expected that over time, the use of expert witnesses would be constrained to the generic process or to times when the risk of the utility was felt to have changed substantially (T. 797-798).

Offsetting these costs, Dr. Waters stated that the generic approach to setting the ROE for the benchmark utilities could lead to a better understanding of the issues since it would be possible to more easily compare and contrast the views of the different expert witnesses (T. 791).

Dr. Waters stated that setting the benchmark ROE for gas and electric utilities at one hearing did not pose problems as long as the individual utility risks were discussed at separate hearings (T. 803).

5.6 Position of CAC(BC) et al

Drs. Berkowitz and Booth also supported the idea of a generic hearing that dealt with the ROE for a benchmark set of utilities and left the establishment of individual utility risk premiums and capital structures to individual utility hearings (T. 1063). The witnesses indicated that setting the ROE for a benchmark set of utilities was appropriate since the evidence related to this issue focused on capital markets. In contrast, the evidence related to the individual utility risk premium and capital structure was concerned with company specific items such as capital expenditure plans. As long as the evidence was divided in this way, the witnesses indicated that they were not concerned with two panels hearing different parts of the revenue requirement application (T. 1068).

Drs. Berkowitz and Booth agreed with other witnesses who indicated that larger utilities could be expected to take the lead in the generic hearing and suggested that this would result in cost savings to smaller utilities which would no longer provide independent generic evidence (T. 1066). An additional benefit of the generic hearing was the bringing together of more information and more ideas due to the greater number of participating parties (T. 1067), although this might act to reduce the cost savings noted above.

The witnesses suggested that the generic hearing be held as close to the test year as possible to reduce forecasting risk (T. 1069).

In argument, counsel for CAC(BC) et al indicated discomfort with the questioning of expert witnesses as to the appropriateness of the generic hearing process, given that some of the questions concerned were legal issues outside their areas of expertise. Instead, she suggested that the Commission should invite formal comments on these issues (T. 1833).

5.7 Position of Gas User Group

The Gas User Group, a customer group whose primary interest was with respect to the ROE and capital structure for BC Gas, stated in final argument that they had supported a trial generic hearing on the hope that it might lead to a reduction in costs. Instead, they indicated that their costs had increased due to the greater number of participants. Therefore, they stated that they would not support further generic hearings, unless changes were made to ensure fairness and efficiency (T. 1881-1882).

5.8 Position of ECA

The ECA supported the concept of a generic rate of return hearing and indicated that they viewed it as having the potential for reducing the long-term costs associated with regulation (T. 1854). In particular, they indicated that they valued the opportunity to have access to a variety of expert witnesses (T. 1856).

5.9 Commission Determinations

There are three major options available to the Commission with respect to the process to determine the appropriate rates of return on common equity and capital structures for the utilities it regulates. First, the Commission could hold a generic hearing which establishes the ROE for a benchmark set of low risk, high grade utilities only. Under this option, the appropriate premiums or decrements off the benchmark ROE and the capital structure of the individual utilities would be determined in either separate processes which follow the generic hearing or as part of each utility's revenue requirement hearing. Second, the Commission could hold a generic hearing which establishes the ROE for a benchmark set of low risk, high grade utilities, the appropriate premium or decrement off the benchmark for each utility and the capital structure for each utility. Third, the Commission could abandon the generic hearing concept and establish the ROE and capital structure separately for each utility within each utility's revenue requirement proceeding.

In considering these options, the Commission is guided by a number of considerations, including the extent of potential cost savings; the parties to whom cost savings are likely to accrue; the need for consistent treatment of utilities; the likely quality of evidence; and the impact on the potential for negotiated settlements.

As indicated in the previous discussion, most parties to the hearing identified the holding of a generic hearing to set a benchmark ROE for a group of low risk, high grade utilities (the first of the three options), as the preferred option for the Commission to follow at this time. Benefits identified included: (i) potential cost savings to the Commission and to Intervenors involved in more than one hearing, since evidence related to economic outlook and capital market conditions would be presented and heard only once; (ii) better quality evidence with respect to economic outlook and capital market conditions since there would be a variety of experts gathered at single point in time; (iii) better quality evidence with respect to individual utility premium and capital structure since these issues would be dealt with in individual utility hearings; and (iv) greater consistency with respect to ROE determinations for individual utilities since the decisions would start from a common base.

The Commission also recognizes that the ROE premium over the set of low risk, high grade utilities and the individual utility capital structures are less likely to change for several years. This is particularly true for mature utilities where the mix of customers is stable and the capital spending programs are identifiable.

Costs associated with this option included increased volumes and rounds of information requests, when compared to the traditional hearing process, resulting from a greater number of participants to the hearing; a potential need for witnesses and Intervenors to appear at two sets of proceedings instead of one. However, it is expected that the burden of information requests would be less severe under this option than this hearing would indicate since under option one the matters for discussion would be limited to issues such as capital market conditions and rate of return tests. A further cost of option one is a decrease in the potential for negotiated settlements, in comparison to the second option, since ROE and capital structure will have to be considered in individual utility hearings.

Many of the benefits associated with the first option are also associated with the second, eg. better quality evidence with respect to economic outlook and capital market conditions. In addition, option two allows for maximum consistency of treatment between utilities since ROE and capital structure determinations are made at the same time and by the same panel and peripheral issues, eg. treatment of deferral accounts, addressed by one utility may be used as a focus for examination of another utility.

Offsets to these benefits include the potential for increased costs to Intervenors concerned with only one utility, although this may be minimized through phasing of the hearing and strict adherence to schedules; and poorer quality evidence with respect to utility specific factors since the evidence will be heard outside of a specific utility hearing.

With the exception of the Gas Users Group, no party advocated a complete abandonment of the generic hearing process. In addition, the Commission's own experience to date has not been such as to warrant a decision to return to the traditional hearing process. Nonetheless, the Commission is mindful that a generic hearing approach, whether limited to consideration of the ROE for a benchmark set of utilities or more broadly defined, is subject to certain costs and risks as well as benefits. Although it appears that many of these costs and risks might be minimized through careful planning and the cooperation of all parties to the hearing, the Commission wishes to explore more fully the implications of these factors. In particular, the Commission is mindful that a generic approach constitutes a new regulatory practice which may have associated legal ramifications that need to be addressed.

Based on the experience this year, the Commission intends to follow the model of a generic hearing which will set the ROE for the set of low risk, high grade benchmark utilities. However, feedback from this Decision, other experiences with generic ROE hearings in Canada and the evolution of financial markets and interest rates in the next year, will all have a bearing on future reviews. The Commission intends to monitor similar regulatory initiatives that are taking place in other jurisdictions and may make further determinations with respect to this issue later in the year.

DATED at the City of Vancouver, in the Province of British Columbia this day of June, 1994.

Dr. M.K. Jaccard
Chairperson

K.L. Hall
Commissioner

P. Bradley
Commissioner

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M. MOSELEY	Commission counsel
MS. J. JANSEN	West Kootenay Power Ltd.
C.B. JOHNSON	BC Gas Utility Ltd.
J. LUTES C.P. DONAHUE	Pacific Northern Gas Ltd.
B. WALLACE	City of Kelowna; City of Penticton; District of Summerland; City of Grand Forks; Princeton Light and Power Company, Limited; Methanex Corporation; Celgar Pulp; Weyerhaeuser; and Cominco
MS. C. MCCOOL	Consumers' Association of Canada, B.C. Branch; B.C. Old Age Pensioners' Organization; Council of Senior Citizens Organizations; Federated Anti-Poverty Groups of B.C.; Senior Citizens Association of B.C.
D. RAWLYK	Energy Resources Management
K.E. GUSTAFSON	Crestbrook Forest Industries Ltd.; Consumers Packaging; Elkview Coal Corporation; Hiram Walker & Sons Limited; Fording Coal Ltd.
D. GEORGE	Kootenay Okanagan Electric Consumers Association and Himself
S. LAMONT	CanWest Gas Supply Inc.

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EXECUTIVE SUMMARY

On April 5, 1994, the Commission began a public hearing into the appropriate rates of return on common equity and capital structure for BC Gas, WKP and PNG. In addition, the Commission heard evidence on future processes or mechanisms that might be employed to improve the determination of ROE and capital structures in future years, including the holding of generic hearings.

After extensive review of the evidence presented by four panels of expert witnesses on behalf of the Applicants and Intervenors, the Commission determines that the required rate of return on equity for a low risk, high grade utility is 10.5 to 10.75 percent. For the purposes of calculating rates, the Commission establishes 10.75 percent as the benchmark rate of return. This return assumes that the yield on long-term Canada bonds will average 7.75 percent in 1994. In addition, this return incorporates a 50 basis point cushion which the Commission expects to be sufficiently generous to cover the risk of dilution and cost of new share issues in other than extraordinary market circumstances.

The Commission finds that the evidence before it does not warrant a reconsideration of its June 9, 1993 Decision with respect to the appropriate capital structure for WKP. Therefore, the Commission directs that for the purposes of determining rates, WKP is deemed to have a common equity component at year-end 1994 of 38 percent and at year-end 1995 of 35 percent. The Commission understands that these translate into mid-year common equity components of 39.0 percent and 36.5 percent, respectively. With respect to the appropriate rate of return on equity, the Commission finds that the appropriate ROE for WKP is 11.0 percent in 1994.

The Commission has seen no evidence to change the judgment contained in the 1992 Decision that 33 percent is an appropriate common equity component for BC Gas. In addition, the Commission holds the view that there is very little difference in risk for BC Gas with no RSAM or with the RSAM (5 percent) option. The Commission also believes that the reduced level of revenue volatility resulting from the RSAM (0 percent) and decoupling options are similar in their impact on utility risk and should lead to a modest reduction in the allowed ROE. Therefore, if the Panel of the Commission charged with determining the desirability of the RSAM proposal accepts the proposal as put forward by the utility or rejects the proposal completely, this Panel of the Commission finds that the appropriate rate of return on common equity for BC Gas is 10.75 percent in 1994. If RSAM (0 percent) or full decoupling is determined to be appropriate, this Panel finds that the appropriate rate of return on equity should be reduced by 10 basis points.

The Commission accepts the capital structure put forward by PNG in its application as constituting a reasonable basis on which to determine rates. In addition, the Commission finds that the appropriate rate of return on common equity for PNG is 11.5 percent for 1994.

In a Decision dated March 11, 1994, the Commission accepted the proposal that the appropriate ROE to be allowed Centra-FSJ would be the simple arithmetic average of the ROEs allowed PNG and BC Gas. Based on the determinations contained in this Decision with respect to those utilities, the Commission finds that the appropriate ROE for Centra-FSJ is 11.125 percent for 1994.

For the purpose of setting the 1995 rate of return on common equity for the Applicant utilities, including Centra-FSJ, the Commission accepts an automatic adjustment mechanism, based on long-term Canada bond yields, as outlined in Chapter 4 of this Decision. The Commission will monitor the fluctuations in long-term Canada bond yields, other market factors, and the general experience with the adjustment mechanism to assess its ongoing appropriateness. If the Commission judges the mechanism to have performed favourably, and capital market conditions so warrant, the Commission may choose to extend the automatic adjustment mechanism for a further one or two years.

The Commission's predisposition is to continue to hold generic hearings which will set the ROE for a set of low risk, high grade benchmark utilities. However, the Commission is unwilling at this time to make an irreversible decision with respect to the timing and or scope of future generic hearings and intends to monitor similar regulatory initiatives that are taking place in other jurisdictions. The Commission may make further determinations with respect to this issue later in the year.

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APPENDIX A - Appearances

APPENDIX B - List of Exhibits