1.0 INTRODUCTION

1.1 History of BC Gas Inc.

In 1988, Inland Natural Gas Co. Ltd. ("Inland") acquired the Lower Mainland Gas Division of British Columbia Hydro and Power Authority. Following that acquisition, the four distribution companies of Inland, Columbia Natural Gas Limited, Fort Nelson Gas Ltd. and B.C. Gas Inc. were amalgamated in July 1989 and operated as Divisions of BC Gas Inc. As part of the acquisition of the Lower Mainland Division, the rates for the sale of gas by the distribution companies of Inland were frozen until the end of September 1991, except for changes in certain identified expenses.

At the end of the rate freeze, BC Gas Inc. applied on November 20, 1991 for an interim and permanent increase in rates of 3 percent over the existing total revenue effective January 1, 1992. The Commission Decision dated August 5, 1992 denied the rate increase and ordered a refund of the interim rate increase. On September 4, 1992, BC Gas Inc. applied for a reconsideration and variance of certain portions of that Decision. By Decision dated November 30, 1992, the Commission denied the Reconsideration Application. An application for a 1993 rate increase of 4.7 percent was made by BC Gas Inc. but was subsequently withdrawn by the Company.

1.2 Corporate Reorganization

The Commission expressed concerns about the activities of the non-regulated businesses ("NRB") of BC Gas Inc. in the August 5, 1992 Decision and encouraged the Company to separate its utility and non-utility assets. In March 1993, BC Gas Inc. applied to the Commission for approval of a corporate reorganization that would comply with the 1992 Decision. A Commission hearing was held into the application and approval was given effective July 1, 1993 to allow the Company owning all of the gas utility assets to be renamed BC Gas Utility Ltd. ("BC Gas", "the Utility", "the Company" or "the Applicant"). A holding company was created and adopted the name BC Gas Inc. which acquired 100 percent of the shares of the Utility and other non-utility investments.

1.3 Service Areas of BC Gas

BC Gas provides service to over 666,000 residential, commercial and industrial customers throughout much of the Province. The Company has centers of operation in Fort Nelson, Prince George, Kamloops, Penticton, Kelowna, Cranbrook and the Lower Mainland of Southwestern British Columbia.

1.4 Rate Design Decisions

The "Phase A" Rate Design hearing was held in December, 1991 to deal with a revised methodology for allocating gas supply costs to customers, tariffs schedules for large volume interruptible, peaking and transportation, and the matter of confidentiality of gas purchase prices. A Decision was issued in February, 1992.

During June to August 1993, the Commission held public hearings into the Company's Phase B Rate Design Application. The hearings were initiated by an earlier Commission direction, by industrial customer complaints and by the Company's desire to review the rate structure of the Utility's various divisions and customer classes.

On October 25, 1993 the Commission issued a Decision on the Rate Design Application. The combined effect of the increase in the cost of gas, effective November 1, 1993, and the changes in rate design, including the creation of seasonal rates, resulted in the following changes to January 1, 1994 rates for residential customers: 17 percent increase in the Lower Mainland (25 percent for the winter period); a 6 percent increase in Inland (12 percent for the winter period); and a 14 percent increase in Columbia (20 percent for the winter period). The Decision also approved the adoption of a postage-stamp delivery charge to residential, commercial and general firm service customers in the Inland and Lower Mainland Divisions.

2.0 THE APPLICATION

2.1 Requests in the Application

BC Gas applied on November 22, 1993 for interim and permanent rates for 1994 and 1995, pursuant to Sections 64, 67 and 106 of the Utilities Commission Act ("the Act"), for all divisions except Fort Nelson. The Application sought a 3.63 percent increase on captive rates (9.21 percent on margin) in 1994. For 1995, the Company sought a further increase of 5.73 percent on captive rates (13.69 percent on margin).

The Application also sought approval for the following items:

- The institution of a revenue stabilization adjustment mechanism ("RSAM") effective January 1, 1994 which would stabilize the Company's margin from deviations in the use-per-customer forecast for the residential and commercial classes during the months of November to March. [This item was subsequently deferred to Phase 2 of the hearing.]

- Approval to apply the Core Market administrative costs to the cost of gas account for the gas supply year. The Core Market administrative costs are related to securing and managing the gas supply for the Core Market and generating off-system sales revenue and other deferral account contributions that are credited back to the Core Market (see Section 5.2).

- A change in the approved unfunded debt rate from 6 percent to 4.5 percent effective January 1, 1994 and to accrue in a deferral account the variations between the approved rate and the actual unfunded rate. Approval is sought for the amortization of the projected December 31, 1993 unfunded debt deferral account balance of $328,000 over two years commencing January 1, 1994 (see Section 3.3 and Chapter 6.0).

- Approval to create a deferral account (see Chapter 6.0) effective January 1, 1994 to record:

  a) the difference between the forecast long-term rate of 8 percent (effective cost of 8.148 percent) and the effective rate achieved upon financing.

  b) the difference between the forecasted principal and timing of the issue and that actually achieved upon financing, with amortization over two years starting on January 1, 1996.

- Depreciation of the Customer Information System ("CIS") over a 15-year straight line period. An Order is requested for the continued recording of Management Information Systems ("MIS") software on a net-of-tax basis (see Section 3.2).

- Deferral of customer communication expenses of $1.555 million in 1994 and $1.405 million in 1995 with amortization over five years commencing January 1, 1994 (rejected per Exhibit 17).

- Deferral of Integrated Resources and Demand Planning ("IRDP") expenses of $1.291 million in 1994 and $1.67 million in 1995 with amortization over five years commencing January 1, 1996 (Exhibit 9). Deferral of expenditures on Demand-Side Management ("DSM") and public consultation with DSM estimated at $2.1 million in 1994 and $4.3 million in 1995 while public consultation is forecast as $205,000 in 1994 and $557,000 in 1995 (deferred to Phase 3 of this hearing).

- Deferral of Natural Gas for Vehicles ("NGV") Fuel Probe program costs of $1.026 million with amortization over five years commencing January 1, 1994 (see Section 3.3).
- Amortization of Management Review costs of $239,000 over two years commencing January 1, 1994 (see Section 5.3).
- Approval to set up a deferral account for administration costs related to buy/sell arrangements (see Section 3.3).
- Approval to dispose of deferral accounts described at Volume 1, Tab 3, pages 1-03-14.11 to 14.14 for an after tax total of $615,000 (see Section 3.3).
- Continuation of a deferral account for new taxes, levies or changes in rates or methods of income taxes, property taxes and levies (Exhibit 9).
- Deferral and recovery of any changes in wages or benefits under the Collective Agreement which expires on March 31, 1994 with amortization over one year (Exhibit 9).
- Deferral of market incentive programs aimed at the commercial and multi-family market which is forecasted to cost $419,000 for 1994 and $432,000 for 1995 (deferred to Phase 3 of this hearing).
- Deferral of any management incentives (Exhibit 9).
- A rate of return on common equity between 12.25 percent and 12.75 percent for 1994 was recommended and a methodology for 1995 based on evidence by Dr. Sherwin and Ms. McShane. BC Gas is requesting a return of 12.25 percent for 1994 (see Chapter 6.0).
- A 33 percent common equity component (see Chapter 6.0).
- Use of the Alternative Dispute Resolution ("ADR") to identify, define and eliminate issues where consensus could be reached with Intervenors (Exhibit 9, Order No. G-10-94).

The reference and/or process of dealing with each of the above items is contained in brackets.

2.2 Forecasts and Updates

Revisions to the Application were filed by BC Gas on March 23, 1994 as Volume 1A. The following changes were made to the Application:

- The requested rate increase to the captive customers for 1994 as a percentage of total revenue declined to 3.12 percent from the previous 3.63 percent. For 1995, the rate increase as a percentage of total revenue dropped from 5.73 percent to 5.2 percent.

- Gas plant in-service and other rate base items were updated for recorded balances as at December 31, 1993.

- Other adjustments were made to sales, cost of gas, Operating, Maintenance, General and Administrative ("O & M") costs, contributions in aid of construction and unamortized deferred charges.

- The cost of unfunded debt was revised from 4.5 percent to 5.0 percent in 1994 and from 4.5 percent to 6.0 percent for 1995. The forecast cost of new long-term issues was increased from 8.0 percent to 9.0 percent for both years.

The changes resulted in the projected 1994 revenue deficiency declining by $2.9 million to $21 million and the projected 1995 revenue deficiency declining by $3.1 million to $36.6 million.

As a result of the negotiated settlement discussed in Section 2.4, BC Gas filed Exhibit 14 projecting a further reduction of its revenue deficiency by $2.3 million to $18.7 million in 1994, and by $6.7 million to $29.9 million in 1995.

During the hearing BC Gas filed Exhibit 15 to update the orders and directives sought from the Commission and to identify the method of disposition for each listed item. **The Commission in general agrees with the disposition proposal subject to the comments in this Decision on certain specific requests.**

2.3 The Public Hearing

Commission Order No. G-120-93 approved an overall interim increase of 2.47 percent (6.26 percent on gross margin) based on a rate of return on common equity of 11.20 percent effective January 1, 1994 subject to refund with interest. Interim approval was also given to RSAM effective January 1, 1994.

Commission Order No. G-130-93 set a public hearing date of April 25, 1994 for the Application. Commission Order No. G-10-94 set the timetable for resolving potential issues by an alternate dispute resolution process except rate of return on common equity and capital structure. A joint hearing was established by Commission Order No. G-4-94 to deal with the rate of return on common equity and capital structure of BC Gas, West Kootenay Power Ltd. and Pacific Northern Gas Ltd. The joint hearing commenced April 5, 1994.

The Commission, by Order No. G-26-94, rescheduled the Revenue Requirements Phase of the public hearing to commence on May 2, 1994. This phase of the hearing is designated Phase 1 and the Decision relating to it is rendered separately herewith. This Phase 1 hearing occupied three hearing days, including final argument.

The Commission, by Order No. G-29-94, rescheduled the examination of Integrated Resource Planning ("IRP"), RSAM and sales forecast as separate phases of the hearing to commence June 6, 1994. These latter hearings are designated Phase 2 (RSAM/Forecasts) and Phase 3 (IRP/DSM) respectively of the 1994/95 Revenue Requirement Application.

Ms. E.C. Sleath, one of the Commissioners in the Phase 1 hearing, will not be able to sit for Phases 2 and 3. This Phase 1 portion of the Decision, therefore, deals with only those issues addressed while Commissioner Sleath was involved.

2.4 Negotiated Settlement

The Alternate Dispute Resolution process was used to identify, define and eliminate issues which would otherwise have gone to the hearing. Commission Order No. G-10-94 set out a timetable for these events. The timetable included prehearing conferences to identify potential issues; workshops to deal with topics which included the Revenue Stabilization Adjustment Mechanism, sales forecasts, O & M, plant additions, Non-Regulated Businesses, Management Information Systems and Integrated Resource Planning and negotiation days to resolve the identified issues. The above activities took place within a tight schedule between March 3 and April 20, 1994. All sessions were open to participation by Intervenors and any interested party.

A tentative settlement was reached on the two major cost factors underlying the 1994 and 1995 Revenue Requirements of BC Gas. The settlement was detailed in a letter dated April 22, 1994 (Exhibit 9), prepared by Commission staff, which solicited Intervenors' responses. The substantial support received (Exhibit 10) warranted the presentation of the negotiated settlement to the Commission on the opening day of the hearing (T. 9). Further oral presentations and arguments were provided by participants. The following day the Commission, after careful consideration, accepted the negotiated settlement.

The reasons for the Commission's support for the negotiated settlement were provided by the Commission Chair in the following statement (T. 127-130):

> "The panel deliberated for some time Monday afternoon to resolve, in our minds, the benefits and demerits surrounding the proposed settlement.
>
> On the one hand we have concluded that the final adjustments to the plant additions and the operating, maintenance and administration budgets indicate an appropriate level of funding for revenue requirements purposes.
>
> Accepting the settlement avoids any fettering of management's responsibility to operate the company while also providing reasonable fiscal caps to ensure that the rates to customers are no more than necessary to provide a safe and efficient operation. The panel recognizes that a detailed review did occur. The submission of Mr. Rawlyk pointed out the detailed information gathering and testing of the individual costs that was undertaken, and Mr. Johnson referred to that period as the inquisition of company witnesses. The panel also recognizes the position taken by Ms. McCool that the Alternate Dispute Resolution process was open to all intervenors and transparent in its work.
>
> The Commission also recognizes that if it is to preserve the integrity of the ADR process the Commission panel would generally prefer not to reject a proposed settlement when the process of negotiation has been complete, the settlement is supported by all of the negotiating parties, the overwhelming majority of other intervenors on the Application have not opposed the proposed settlement, and the panel can conclude that any opposition to the proposed settlement is not of so substantive a nature as to warrant its rejection. In this case only one intervenor raised objections to the proposed settlement, and those objections were directed to the proposed settlement on O, M & A.
>
> On the other hand the panel must respond to the responsibilities outlined by Mr. Fulton to ensure that the Commission discharges its statutory responsibility to ensure that the rates of the utility are fair, just and reasonable. While the without-prejudice nature of the bargaining position taken by participants prevented the panel from participating in the detailed negotiations that have occurred, after reviewing our own notes with respect to the material in the Application we are supportive of the adjustments to rate base plant additions that recognize reductions in the area of information technology and the adjustment to the process of approving buildings in the Lower Mainland.
>
> On the O, M & A settlement the panel recognizes that many of the specific issues we have identified from the Application will have been reflected in the downward adjustment to the Applicant budgets. We are supportive of the final outcome adjusting the 1993 expenditures and the factors related to customer additions, productivity improvements and inflation estimates. It should be noted that the Commission nonetheless believes that there is value in having a detailed review of the utility's activities from time to time. However, the 1992 revenue requirement decision provided such an in-depth review. Consequently the settlement at this juncture may provide a good balance between periodic detailed public reviews and a desire not to diminish the responsibility and accountability of BC Gas management to run the utility.
>
> The submission of Mr. Hope on Monday focused on indicators of productivity that should be reflected in the O, M & A budget. Notwithstanding that submission, this Commission panel concludes that the productivity factors included in the settlement provide an appropriate balance between the interests of the customers and the utility, so that customers

should expect a continued high-quality service from the utility through its efficient operation.

As a result of the foregoing this Commission panel concludes that the proposed settlement is in the public interest. Detailed reasons for decision will be included in the panel decision document. In final argument the panel would appreciate any suggestions that participants have with respect to future settlement processes as a result of the experience that has been gained here. Alternatively the Commission has circulated a draft ADR proposal and participants may wish to comment on that draft, incorporating views gained from the BC Gas settlement activity."

2.5 Future Alternate Dispute Resolutions ("ADR")

Intervenors responded to the Commission's request for feedback and recommendation on the ADR in their final arguments.

BC Gas felt that the ADR process worked well in this Application, but the Utility remains "on the fence" as to whether further ADR's will result in better and more efficient outcomes compared with public hearings. The Utility gave recommendations on matters such as independent facilitators, the role of Commission staff and a strengthening of "Issues Day". BC Gas also identified some practical problems which should be addressed.

Consumers' Association of Canada (B.C. Branch) supported measures to improve decision making but felt that we must recognize that the nature of the process is adversarial and any ADR should have an escape clause back to the public process, since some issues may not be able to be resolved.

Other Intervenors also addressed the ADR process with varying views on the use of facilitators and the role of Commission staff.

The Commission thanks the participants for their input to the development of ADR. This information will be added to the responses that have been received to the Commission's draft policy paper on ADR. That paper is expected to be updated and made available to stakeholders in July, 1994.

2.6 Use of Gas Cost Reconciliation Account ("GCRA") Balance

Since the inception of the GCRA effective January 1, 1993, the account accumulated a credit balance of approximately $25 million as at December 31, 1993, which is reflected on a net of tax basis of approximately $13.927 million in Exhibit 25. The purpose of the account is to protect the Utility from variations in gas supply costs by capturing the differences between forecast gas costs and the actual recovery of those costs from the Utility's gas sales. This account balance grew to an abnormally large level due to higher than forecast sales in some months of 1993, and credits from interruptible, off-system and non-core market sales. This trend is not likely to continue into future years, because the Utility has reflected the expectations of off-system sales revenues into rates at the start of each future period so that only the difference in revenue flows to the account.

BC Gas proposed the following disposition of the GCRA balance (Exhibit 15):

> "Upon determination of the final rate impacts for both test years, the rate increases will be reflected in rates for each class. However, for the Core Market Customer Classes ("CMCC" - being all customer classes other than those using interruptible or transportation service) a negative rider equal to the rate increase applicable to a rate would be applied with the amount of the negative rider being withdrawn from existing (and future) GCRA deferral account credit balances.
>
> To the extent GCRA deferral accounts are exhausted, a deferral balance is to be created.
>
> Any credit balances existing in the GCRA at the end of 1994 are to be carried over to the following year to offset the rate increases in the same manner as in 1994."

The Commission approves the refunding of the excess credit, over the $5 million buffer as determined in the Phase B Rate Design Decision (page 64), to the Core Market customer classes by way of an offset to the 1994 and 1995 rate increases.

The proposal contained in Exhibit 15 to utilize the GCRA credits to offset rate increases for core market customer classes via "negative riders" is accepted with the provision that a $5 million buffer is maintained. BC Gas will make a full refund of the interim increase collected to the date of refund, plus interest, to core market customers, and partial refund to other non-core customers as required in accordance with the terms contained in Order No. G-120-93.

3.0 RATE BASE

3.1 Plant Additions

As a result of the negotiated settlement between the Utility and Commission staff, rate base plant additions have been set for rate making purposes as cited from Exhibit 9.

The rate base determination followed detailed reviews of the capital budgeting processes and the individual expenditures by category. The Company's original Application asked for $196,998,000 in 1994 and $190,560,000 in 1995 for rate base plant additions. A series of modifications reduced the Company's proposed rate base plant additions to $186,223,000 in 1994 and $168,164,000 in 1995. The Settlement Proposal establishes the 1994 rate base plant additions to be $166 million in 1994 and $138 million in 1995.

The Commission accepts the rate base plant additions for 1994 and 1995 as established in the settlement proposal (Exhibit 9).

Commission staff have expressed concern, particularly with respect to expenditures on information technology and the determination of new buildings in the Lower Mainland. BC Gas has responded positively by very significantly curtailing its information technology activities at this time. The matter of determination of new buildings is an ongoing review activity between Commission staff and the Utility.

Certain accounting issues, as set out on Exhibit 16, were referred to a working committee which was to be comprised of utility representatives, interested parties and Commission staff. A recommendation was made to the Commission at Phase 2 of the hearing.

3.2 Management Information Systems ("MIS")

BC Gas has encountered uncertainty as to the viability of the Theseus project, which is at the heart of the proposed Customer Information System ("CIS"). Parties in the MIS workshop dated March 28, 1994 agreed that a review of the CIS should not be included in this hearing but should await future review of the Theseus schedule. Deloitte & Touche Management Consultants, who are retained by Commission staff, will also testify about the monitoring of the CIS and other MIS projects at that time.

The Commission gave interim approval to the recording of MIS software on a net after tax basis by Order No. G-33-93 (Item 5, Exhibit 7). **The Commission continues to believe that this method can**

avoid the undesirable impact on the Utility's revenue requirements due to fluctuations of rapid tax write-off items between test years and non-test years, and approves this method together with the request for CIS depreciation over a 15-year straight line period on a permanent basis effective January 1, 1994. However, the Commission will continue to monitor the effect of this methodology and make amendments if necessary in future rate cases.

3.3 Deferred Costs

Other than amendments required to reflect Commission directions in this Decision and those on separate BC Gas applications relating to Furnace Repair Plan costs and IRDP costs, the Commission accepts BC Gas' revised schedule of Deferred Charges and Amortization (Exhibit 25) which records costs on a net after tax basis. Exhibit 25 also removes the impact of forecast IRDP and DSM costs (T. 216) which are subject to review in Phase 3 of the hearing.

4.0 GAS PURCHASES

The Commission's approval of the Gas Cost Reconciliation Account in the Phase B Rate Design Decision, together with its review and approval of gas supply contracts under Section 85.3 of the Act has addressed all of the potential concerns on this matter.

5.0 OPERATING EXPENSES

5.1 Operations, Maintenance, General and Administrative Costs

In addition to a negotiated settlement on rate base plant additions, O & M costs were also agreed and approved by the Commission panel during the hearing (T. 127). The BC Gas Application had requested $99.3 million for 1994 and $110.8 million for 1995 in addition to certain O & M costs on which the Company sought to defer recovery. **The approved costs are $97 million and $101.5 million for 1994 and 1995 respectively.**

5.2 Core Market Administrative Costs

As part of the O & M costs settlement, it was agreed that Core Market administrative costs would be segregated from the O & M cost category as an individual cost so that its cost efficiency and effectiveness can be measured independently.

5.3 Management Review Costs

BC Gas was required as part of its obligation in the purchase of the Lower Mainland Gas Division from British Columbia Hydro and Power Authority to perform a management review every four years commencing 1992. The cost of such a review, originally estimated at $500,000, was allowed to be deferred by Order No. G-33-93 which also approved the 1993 BC Gas Revenue Requirement Withdrawal Application.

The Company submitted (T. 187) that the final costs of approximately $181,000 should be recovered from customers since the management review (Exhibit 22) had also satisfied a Commission requirement in the August 5, 1992 Decision.

The Commission considers that the cost incidence was primarily intended to satisfy a requirement of Order in Council 1819/88 and was apparently for the benefit of shareholders. Although the scope of the review was modified with the intent also to comply with the 1992 Commission Decision, the Commission believes that the review cost should be shared equally by both shareholders and customers in this instance. This ruling should not be considered a precedent for similar cost allocation by BC Gas in any future management reviews required by Order in Council 1819/88.

5.4 Executive Compensation

At this hearing two issues with respect to Executive Compensation remained to be resolved by the Commission. The first issue was related to a deferral account of $606,000, established as part of the withdrawal of the 1993 Revenue Requirement Application by BC Gas. At that time the Utility requested the opportunity to argue before the Commission that this money for Executive bonuses should be recovered from customers. However, in his opening statement Mr. Lotochinski, for BC Gas, stated that bonuses in excess of the deferral amount had been paid, but because the Company expensed the costs in 1993 it no longer sought recovery of the funds. Therefore this deferral account is eliminated.

The second issue for consideration by the Commission Panel related to the Management Performance Criteria in the incentive plan for Executives. BC Gas made it clear in final argument that the funding of executive pay in 1994 and 1995 would come out of the agreed settlement and that they did not wish to have the Commission review the issue of the amount of total compensation for executives at this time. The Commission agrees that it will not rule in this Decision on the total compensation available to executives since there was very little information led to justify a change from the determinations previously made in the 1992 Revenue Requirement Decision.

In the 1992 Decision the Commission directed BC Gas to revamp its performance criteria to motivate its executives to meet the demands of customers as well as shareholders. Virtually the entire previous performance criterion was geared to an earnings test (T. 143). Mr. Lotochinski testified (T. 143) that, "In 1993 the Board of Directors did approve completely revamped incentive plan for executives which, while still containing an element of earnings test, added a number of other components including cost control, efficiency, public and employee safety, customer satisfaction and reliability and customer service". The Utility states that it sought feedback from the Commission so that the Management Resources Committee of the Board of BC Gas could assess whether the Commission viewed favourably the performance measures contained in the revised incentive plan.

Commission Counsel examined the various criteria for incentives and the "stretch objective" that must be met to obtain bonus payments. BC Gas testified that the target bonus is 30 percent of base compensation (T. 198).

The examination of the stretch objectives indicates to the Commission that the attainment of a 30 percent bonus above base compensation is likely to occur provided the executive has achieved only adequate performance. For example, the stretch objective for the financial results objective is the utility budget or the Commission Decision, as applicable. However, these measures are set so that the Utility should be able to provide fully adequate service to customers under normal circumstances, rather than by exceptional performance. Consequently, the Commission views the Utility's action as essentially setting the average expected utility executive total cash compensation at a level 30 percent above the findings of the Commission in 1992. The breadth of the bonus compensation ranging from 0 to 50 percent of base salary also appears to be very large.

With respect to executive pensions the Commission understands that BC Gas is prepared to work with Commission staff to review the pension arrangement and funding for both executives and other management categories. A report is to be made later this year. Until then BC Gas will comply with the 1992 Decision that bonuses not be included in determining executive pensions for funding by customers.

With respect to the broadened make-up of the incentive plan the Commission generally endorses the categories chosen by BC Gas to make up the incentive measures. However, the Commission is not completely convinced of the rationale for executive bonuses as part of the executive compensation package. While the Commission recognizes BC Gas' right to set executive compensation packages within the framework of the settlement negotiated for the next two years, the whole matter of executive compensation will be reviewed in detail at the next Revenue Requirement hearing for BC Gas.

5.5 Hearing Costs

In Exhibit 25 BC Gas forecast hearing costs of approximately $550,000 on a before tax basis. BC Gas will revise these costs to include allocation from the joint rate of return hearing, approved Intervenor funding, and the Commission's costs.

Due to the two-year test period aspects of the Application and the longer term impacts of some of the issues, the Commission believes a three-year amortization period of the final costs should be adopted.

5.6 Riders 1 to 5

The riders proposed in Exhibit 1, Tab 16 to comply with the directions contained in the Phase B Rate Design Decision are approved.

6.0 CAPITAL STRUCTURE AND RETURN

As indicated in Section 2.3 of this Decision, the Commission established a joint hearing to set the appropriate rate of return on common equity and capital structure of BC Gas, West Kootenay Power Ltd. and Pacific Northern Gas Ltd.

In a Decision dated June 10, 1994, the Commission found the appropriate rate of return on common equity for BC Gas was 10.75 percent for 1994 on an equity component of 33 percent subject to the Phase 2 Decision accepting the Utility's RSAM proposal or rejecting the proposal completely. As indicated in Chapter 3 of the Joint Return on Equity ("ROE") Decision, if the Phase 2 Decision approved an RSAM with 0 percent deadband or full decoupling, then the appropriate return on equity should be reduced by 10 basis points. For 1995 the rate of return on common equity will reflect an adjustment process as discussed in the Joint ROE Decision and a common equity component of 33 percent.

The request for interim and permanent increases as amended by BC Gas in Exhibit 14 will be further adjusted to reflect the several directions contained in this Decision and others contained in the joint rate of return Decision wherever applicable to BC Gas, and in the upcoming Phase 2 and Phase 3 Decisions. At that time, BC Gas will file amended schedules incorporating the above adjustments and revised hearing costs for the Commission's final approval on the 1994 and 1995 Revenue Requirement of BC Gas.

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

Dr. M.K. Jaccard

F.C. Leighton

E.C. Sleath

APPEARANCES

G.A. FULTON	Commission Counsel
C.B. JOHNSON	Counsel for BC Gas Utility Ltd.
R.B. WALLACE	Weyerhaeuser Canada Ltd., Cominco Ltd. and Celgar Pulp Company
MS. C. McCOOL	Consumer's Association of Canada (B.C. Branch), The British Columbia Old Age Pensioners Organization, Council of Senior Citizen's Organization of B.C., Federated Anti-Poverty Groups of B.C., Senior Citizens' Association of B.C. and West End Seniors' Network
D. RAWLYK	Energy Resources Management
R.T. O'CALLAGHAN	R.T. O'Callaghan & Associates, Inc.
P. KACIR	Crestbrook Forest Industries Ltd., Consumers Packaging, Elkview Coal Corporation, Hiram Walker & Sons Ltd., Fording Coal Ltd.
MR. LEDERHOF	Ecology Circle
MR. DEREK HOPE	Himself

LIST OF EXHIBITS

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Volume 2 - Application of BC Gas Utility Ltd.	2
Volume 3 - Application of BC Gas Utility Ltd.	3
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EXECUTIVE SUMMARY

This Decision of the British Columbia Utilities Commission deals with Phase 1 of the BC Gas Utility Ltd. ("BC Gas") application for a two-year test period. The revised application requested a rate increase to captive customers as a percentage of total revenue of 3.12 percent for 1994 and 5.2 percent for 1995. The Phase 1 hearing commenced on May 2, 1994 and occupied three days which included final argument.

The Commission, by Order No. G-29-94, rescheduled the examination of Integrated Resource Planning ("IRP"), Demand-Side Management ("DSM"), Revenue Stabilization Adjustment Mechanism ("RSAM") and sales forecasts as separate phases of the hearing to commence June 6, 1994. These latter hearings are designated as Phase 2 (RSAM and forecasts) and Phase 3 (IRP and DSM) of the 1994/95 Revenue Requirements Application.

An Alternative Dispute Resolution process was used to identify, define and eliminate issues that would have otherwise gone to the Phase 1 hearing. Prehearing conferences, workshops and negotiation days were held to resolve the identified issues with participation open to Intervenors and any interested party. A tentative settlement, as detailed in Exhibit 9, was reached on rate base plant additions and operating, maintenance and administrative expenses for 1994 and 1995. The Commission, after careful consideration, accepted the negotiated settlement.

In this Decision the Commission confirmed the following:

1. The proposal contained in Exhibit 15 to utilize the Gas Cost Reconciliation Account credits to offset rate increases for core market customer classes via "negative riders" is accepted with the provision that a $5 million buffer be maintained. BC Gas will make a full refund of the interim increase collected to the date of refund, plus interest, to core market customers, and partial refund to other non-core customers in accordance with the terms contained in Order No. G-120-93.

2. The riders proposed in Exhibit 1, Tab 16 to comply with the directions contained in the Phase B Rate Design Decision are approved.

3. In a Decision dated June 10, 1994, the Commission found the appropriate rate of return on common equity for BC Gas was 10.75 percent for 1994 on an equity component of 33 percent subject to the Phase 2 Decision accepting the Utility's RSAM proposal or rejecting the proposal completely. As indicated in Chapter 3 of the Joint Return on Equity ("ROE") Decision, if the Phase 2 Decision approved an RSAM with 0 percent deadband or full decoupling, then the appropriate return on equity should be reduced by 10 basis points. For 1995 the rate of return on

common equity will reflect an adjustment process as discussed in the Joint ROE Decision and a common equity component of 33 percent.

4. The request for interim and permanent increases as amended by BC Gas in Exhibit 14 will be further adjusted to reflect the several directions contained in this Decision and others contained in the joint rate of return Decision wherever applicable to BC Gas, and in the upcoming Phase 2 and Phase 3 Decisions. At that time, BC Gas will file amended schedules incorporating the above adjustments for the Commission's final approval on the 1994 and 1995 Revenue Requirement of BC Gas.

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