BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-85-97

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by BC Gas Utility Ltd.
for Approval of a Performance Based Rate Plan to
Determine Revenue Requirements for the Years 1998 - 2002

BEFORE:	L.R. Barr, Deputy Chair and Acting Chair K.L. Hall, Commissioner P.G. Bradley, Commissioner	July 23, 1997

O R D E R

WHEREAS:

A. On February 5, 1997 BC Gas Utility Ltd. ("BC Gas") filed with the Commission its Performance Based Rate Plan and Revenue Requirements Application 1998 - 2002 (the "Application") for approval to set rates for the years ending December 31, 1998 through 2002; and

B. The Commission reviewed the Application and issued Order No. G-13-97 setting down a Pre-Hearing Conference to commence on February 28, 1997. Following the Pre-Hearing Conference, the Commission issued Order No. G-24-97, which included a Regulatory Agenda and Timetable, setting a second Pre-Hearing Conference for April 24, 1997 and a public hearing, if required, to commence June 3, 1997. On April 24, 1997 the Commission, by Order No. G-47-97, amended the dates set out in the Regulatory Timetable and revised the public hearing date to June 23, 1997; and

C. Commission Order No. G-68-97 cancelled the public hearing scheduled for June 23, 1997 and allowed for a rescheduling by way of a future Commission Order; and

D. The Alternative Dispute Resolution ("ADR") process commenced on June 2, 1997 and, on June 26, 1997, BC Gas, ADR participants and Commission staff agreed to a proposed settlement agreement; and

E. On July 10, 1997 the proposed settlement agreement was circulated to all Registered Intervenors and the Commission Panel. No comments were received; and

F. The Commission has reviewed the proposed settlement agreement and sets out its views in the Reasons for Decision issued concurrently with this Order.

NOW THEREFORE the Commission orders as follows:

1. The Commission accepts the terms of the proposed settlement agreement as revised by its Consolidated Settlement Document and issues its Reasons for Decision.

2. BC Gas will comply with all the terms contained in the Consolidated Settlement Document accompanying the Reasons for Decision.

3. BC Gas is to inform all customers of the effect on rates of this Decision.

4. The public hearing into the application is not required and is therefore cancelled.

DATED at the City of Vancouver, in the Province of British Columbia, this 25th day of July, 1997.

BY ORDER

Original signed by:

Lorna R. Barr
Deputy Chair and
Acting Chair

Attachment

BRITISH COLUMBIA UTILITIES COMMISSION

IN THE MATTER OF

BC Gas Utility Ltd.

REVENUE REQUIREMENTS APPLICATION 1998 - 2002

Reasons for Decision

July 23, 1997

BEFORE:

Lorna R. Barr, Deputy Chair
and Acting Chair
Ken L. Hall, Commissioner
Paul G. Bradley, Commissioner

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REASONS FOR DECISION

Introduction

BC Gas Utility Ltd. ("BC Gas") filed an application dated February 5, 1997 (the "Application") with the British Columbia Utilities Commission (the "Commission", "BCUC") to establish the method for determining its revenue requirements and for approval to set rates for the five years ending December 31, 1998 to 2002.

On February 10, 1997, the Commission issued Order G-13-97 setting a pre-hearing conference to commence February 28, 1997. Following the pre-hearing conference, the Commission issued Order No. G-24-97 which included a regulatory timetable, setting a second pre-hearing conference for April 24, 1997 and a public hearing, if required, to commence June 3, 1997. Subsequent to the second pre-hearing conference the Commission issued Order No. G-47-97 setting down a revised regulatory timetable which provided for, among other matters, rescheduling the public hearing to June 23, 1997. The timetable also provided for public workshops regarding the Application; a process for filing information requests by parties and responses by BC Gas; and an Alternative Dispute Resolution process ("ADR") to negotiate a settlement of issues related to the Application. BC Gas conducted public workshops on March 10, 11 and April 16, 1997. Information requests were filed and an additional 3 volumes of information responses and other data were provided by BC Gas.

The negotiation sessions commenced on June 2, 1997 and continued on various dates through to June 26, 1997 when a negotiated settlement was reached between BC Gas and the parties to the negotiation. The three year proposed settlement agreement was circulated to the ADR participants. Endorsements of the proposed settlement agreement by all of the ADR participants were received at the Commission by July 10, 1997. Subsequently, the proposed settlement agreement was circulated to all registered intervenors for comments by July 18, 1997 and no comments were received. The Commission panel for this proceeding also received a copy of the proposed settlement agreement and letters of endorsement.

The impact of the applied-for rates and the proposed settlement agreement on customer costs for natural gas service (gross margin) is as follows:

	1998	1999	2000	2001	2002
Rate Impact as a % of Gross Margin applied for in original application (May 5, 1997 revision)	6.40	3.40	2.70	1.90	1.60
Rate Impact as a % of Gross Margin (proposed settlement agreement)	1.85	2.00	2.00	N/A	N/A

The Commission notes that the participants expect that the gross margin rate impact on the Company's firm sales customers will be further reduced as a result of amortization of Gas Cost Reconciliation Account balances.

The Commission Panel has now reviewed the proposed settlement agreement as well as the letters of endorsement and comment from the ADR participants and has concluded that it should accept the settlement. Many of the elements within the proposed settlement agreement do not require special comment. However, the Commission did wish to express its views on several key issues that it noted in arriving at its decision and these Reasons for Decision provide those views.

Table 1 sets out key comparisons between the proposed settlement agreement and the Application as revised on May 5, 1997 by BC Gas.

Table 1
Key Aspects of proposed Settlement Agreement

	BC Gas Application	Proposed Settlement Agreement
Term	5 years	3 years
Productivity	1998 - 1% 1999 - 1% 2000 - 1%	1998 - 2% 1999 - 2% 2000 - 3%
Capital Structure	35%	33%
Capitalization of Overhead	1998 - 10.27% 1999 - 10.27% 2000 - 10.27%	1998 - 20% 1999 - 20% 2000 - 16%

The Commission has also created a new document called the Consolidated Settlement Document which incorporates editorial changes as proposed by BC Gas, and one other change as follows. In the subsection entitled "DSM Achievement Incentive" paragraph 6 originally read "The Company will apply to the Commission for funding of new programs where required". The Commission has changed this wording to "The Company will apply to the Commission for **program changes** where required". The Commission made the change as it concluded that the proposed wording may have arguably fettered the Commission in its discretion as provided for in the B.C. Utilities Commission Act.

Commission Comments on Key Issues:

Term

BC Gas applied for a five year term while the parties to the agreement agreed to a term of three years. The Commission considers a three year term is appropriate. It provides a long enough period to allow incentives to perform and at the same time balances the risks and other concerns with respect to changes that could occur over an extended period of time. The Commission is aware of some five year settlements which have been implemented for pipelines, but the Commission is of the view that the number of variables of change that can occur for a Local Distribution Company ("LDC") make it more appropriate to look at shorter terms. Pipelines typically have a limited number of shippers and more discrete cost projections.

Operating and Maintenance Costs ("O&M")

The formula used to develop O&M costs has been previously utilized in the settlements with respect to BC Gas and West Kootenay Power. From this experience, the Commission is satisfied that the methodology of adjusting a base cost for the growth in customers, productivity and inflation has provided appropriate targets for developing incentives. Attached to the Consolidated Settlement Document is a letter from Commission staff dated July 15, 1997 (Appendix B) which provides three examples of how productivity from capital projects will be eligible for inclusion within the O&M productivity targets.

Demand Side Management ("DSM")

The DSM Achievement Incentive represents the second time the Commission has endorsed a mechanism to pursue cost effective DSM resources. However, it is still a new feature in the regulatory environment and very little knowledge has yet been accumulated as to its success or failure. The Inland/Industrial group, in their letter of acceptance of the settlement, pointed out that "the settlement agreement should explain that the DSM programs and incentives are to be accounted for within the rate classes to which they relate." In the Commission's view, this is adequately covered in the settlement agreement, paragraph 9 in the subsection entitled "DSM Achievement Incentive".

Capital Efficiency Mechanism

This is the first significant capital efficiency mechanism that the Commission has approved. It is designed to provide an incentive for the utility to improve its costs of installing mains, services, meters and "other" plant. The range of incentive has been narrowed and the amount of the efficiency adjustment reduced from that originally filed in the Application. Due to the innovative nature of this particular mechanism, the Commission will be closely monitoring both the operation and results flowing from the use of the mechanism.

Overhead Capitalization

The Commission is in agreement with the move to reduce the capitalization of overheads from 22.5% to 16% over the three year period. The change is directionally correct in that a mature utility such as BC Gas should be lowering its overhead charges as capital projects are reduced as a proportion of total expenditures, and the customers that are benefiting from the capital projects are paying for them in an accelerated manner. The Commission also believes that, in undertaking and achieving the changes in overheads capitalization, the reductions should not lead to significant rate impacts.

Annual Review and Quality of Service

The Commission endorses the provision for an annual review. This allows the Commission to discharge its responsibility to maintain oversight of the utility and establish rates for each year. The Commission views the inclusion of service quality indicators as an important component of any incentive rate scheme. Such indicators ensure a utility will appropriately balance its obligation to provide safe, secure, high quality and non-discriminatory service to customers at the lowest rates possible while also providing an opportunity for shareholders to earn a fair return on their investment.

DATED at the City of Vancouver, in the Province of British Columbia this 25th day of July, 1997.

Original signed by:
Lorna R. Barr, Deputy Chair
and Acting Chair

Original signed by:
Ken L. Hall
Commissioner

Original signed by:
Paul G. Bradley
Commissioner

CONSOLIDATED SETTLEMENT DOCUMENT
BC GAS UTILITY LTD. 1998 - 2000 REVENUE REQUIREMENTS

Background

BC Gas Utility Ltd. ("BC Gas") filed an application dated February 5, 1997 (the "Application") with the British Columbia Utilities Commission (the "Commission", "BCUC") to establish the method for determining its revenue requirements for the years 1998 to 2002.

On February 10, 1997, the Commission issued Order G-13-97 setting a pre-hearing conference to commence February 28, 1997. Following the pre-hearing conference, the Commission issued Order No. G-24-97 which included a regulatory agenda and timetable, setting a second pre-hearing conference for April 24, 1997 and a public hearing, if required, to commence June 3, 1997. Subsequent to the second pre-hearing conference the Commission issued Order No. G-47-97 setting down a revised regulatory agenda and timetable rescheduling the public hearing to June 23, 1997. The regulatory agenda included public workshops regarding the Application; a process for filing information requests by parties and responses by BC Gas; and an Alternative Dispute Resolution process ("ADR") to negotiate settlement of issues related to the Application. BC Gas conducted public workshops on March 10, 11 and April 16. Information requests were filed and an additional 3 volumes of information responses and other data were provided by BC Gas.

The negotiation sessions commenced on June 2, 1997 and continued on various dates through to June 26, 1997. Parties represented during the settlement negotiations were BC Gas; Consumers Association of Canada (B.C.), B.C. Old Age Pensioners' Organization, Council of Senior Citizen's Organizations of B.C., Federated Anti-Poverty Groups of B.C., Senior Citizen's Association of B.C., West End Senior's Network, and the End Legislative Poverty & Tenant's Right Coalition, represented by the British Columbia Public Interest Advocacy Centre; Lower Mainland Large Volume Gas Users Association; R.T. O'Callaghan & Associates (not available for the final two negotiating sessions); Fording Coal Ltd.; Association for the Advancement of Sustainable Energy Policy; Cominco Ltd., Weyerhaeuser Canada Ltd. and Celgar Pulp Company; and British Columbia Utilities Commission Staff.

Multi-Year Settlement

This document sets out the terms of a three year settlement reached during the negotiations for setting the revenue requirements and rates of BC Gas. The margin and rate impacts arising from the settlement are summarized on the schedules in Appendix A. The impacts are estimates and are based on several assumptions (subject to vary in the manner as discussed below). These are subject to change each year and relate to factors including:

a) the rate of return on common equity
b) revenues
c) customer additions
d) taxes
e) inflation
f) short and long term debt interest rates
g) rate base additions
h) effect of capital efficiency mechanism
i) capital projects approved under applications for Certificate of Public Convenience and Necessity (CPCN's)

The estimated gross margin impacts resulting from the settlement, as set out in Appendix A, are:

	1998		**1999**		**2000**	
	Core	Non-Core	Core	Non-Core	Core	Non-Core
Rate Impact as a % of Gross Margin	1.85	1.85	2.00	2.00	2.00	2.00

Based on the underlying assumptions, the gross margin rate impact on Core market customers are expected to be further reduced to about 0% in each year as a result of amortization of GCRA balances.

The settlement is the culmination of negotiations among parties who have many diverse interests. The settlement represents numerous compromises among the parties and consists of a settlement package from which no part can be severed. The issues resolved in the settlement negotiations are numerous and complex. Taken as a whole, the settlement represents a balance of interests and an overall consensus among the participating parties.

Term

The parties have agreed to a term of 3 years, namely the calendar years 1998, 1999 and 2000 (the "Term").

Productivity

Productivity shall be 2% in 1998, 2% in 1999 and 3% in 2000. References to "Productivity" in this document are references to those productivities except where stated otherwise.

Inflation

Several elements of the revenue requirement determination methodology are dependent on an inflation rate forecast. The forecast rate of inflation to be applied will be the consumer price index forecast for British Columbia.

The BC Gas proposal utilizing the forecasts for the next calendar year B.C. CPI by the Toronto-Dominion Bank, the Royal Bank of Canada, B.C. Ministry of Finance and the Conference Board of Canada (produced July to September) is accepted (hereinafter referred to as "forecast B.C. CPI").

References to "Inflation" in this document are references to this forecast of B.C. CPI except where stated otherwise.

Capital Structure

The common equity thickness for BC Gas will remain at 33%. In respect to its preference shares which are redeemable in 1999 and 2000, BC Gas will redeem such preference shares and replace the same with long term debt as redemption occurs.

Rate Of Return On Common Equity

The rate of return on common equity for BC Gas will be reset annually in accordance with the Commission's automatic rate of return adjustment mechanism.

Gas Costs

- The gas costs of BC Gas will be set in the manner currently approved by the Commission and customer rates will be adjusted in accordance with the currently approved gas cost allocation methodology.

- The Gas Cost Reconciliation Account will continue in the manner as approved by the Commission.

- The current Off System Incentive Plan will expire November 1, 1997. The parties agree to enter into discussions to determine the form of a successor gas cost incentive plan both for the short term and the long term. Any subsequent plan will be reviewed by interested parties before being submitted to the Commission for approval.

Revenues

- Both core market and non-core market revenues will be forecast each year in accordance with the methodologies employed by BC Gas and will be reviewed at the Annual Review before being submitted.

- The methodology for forecasting residential and commercial sales is established but industrial sales forecasts will be reviewed annually.

- The Rate Stabilization Adjustment Mechanism ("RSAM") will continue in the manner as approved by the Commission.

- Customer Additions will be forecast for each year of the Term, in accordance with the methodology employed by BC Gas and approved by the Commission.

Operating & Maintenance Costs ("O&M")

The O & M levels for each year of the Term will be determined in accordance with the following formula:

[Base Cost x (1 + Growth in Customers - Productivity) x (1 + Inflation)] + Cost of Defined Required Incremental Activities

Where:

Base Cost means: for 1998 this will be $142,760,000.

e.g., 1998 O&M level base cost $142,760,000 x (1 + 2.10% - 2.00%) x 1.01 = $144,334,000 allowed O&M for 1998 excluding DRIA for calculating the allowed O&M level for each subsequent year, the previous year's allowed O&M adjusted for projected actual customers will be the revised base to which customer growth, productivity and inflation will be added.

e.g., 1999 O&M level \$144,334,000 x $\dfrac{\text{1998 Projected Actual Customers}}{\text{1998 Forecast Customers}}$

= revised base x formula = 1999 allowed O&M excl. DRIA

Growth in Customers means:	the forecast percentage growth in the average number of customers for the year over the previous year.
1998 Projected Actual Customers:	The estimate of actual average customers during 1998 at the November 1998 workshop
1998 Forecast Customers:	The forecast of average customers during 1998 at the November 1997 workshop.

In the event BC Gas files an application for a revenue requirement increase in 2001, the Base Cost O&M level to be reflected in rates for 2001, before any increase for inflation and growth in customers, will be that arising from 2000, subject to exogenous factors and DRIA.

Productivity and Retail Markets Downstream of the Meter (RMDM)

One instrument that the Company may use to achieve the targeted productivity gains is shedding, altering or reducing utility activities pursuant to the Commission's policy on RMDM.

BC Gas will be entitled to capture the benefits of improved efficiencies, reduced costs, or other financial savings achieved through RMDM, for the duration of the test period. Adjustments in utility rates during the test period arising from RMDM will be limited to reflecting the reduction of services that had been previously included in customers' bundled utility services. For further clarity the following hypothetical example distinguishes between improved efficiencies eligible for productivity and reduced services not eligible for productivity

Example:

BC Gas determines that outsourcing customer billing will reduce the cost of this function from \$1.00/per customer to \$0.79 and the third party will charge customers directly. The efficient gain of \$0.21 is eligible for productivity but the rates will be rebased to reflect the \$0.79 now paid directly to the third party.

O&M Productivity and Capital Projects

Improved efficiencies, reduced costs, or other financial savings achieved by BC Gas as a result of capital projects approved by the Commission pursuant to applications for Certificates of Public Convenience and Necessity may also be used by BC Gas to achieve the targeted O&M productivity levels.

DEMAND SIDE MANAGEMENT AND INCENTIVES

The Demand Side Management expenditure levels are forecast to remain constant over the Term, namely $1.624 million per year as a DRIA.

DSM Achievement Incentive

The following DSM Achievement Incentive is to be implemented. It is designed to encourage BC Gas to pursue cost effective demand side management resources.

1. Only energy efficiency programs are included in the mechanism.

2. A threshold level of 75% of the annual forecast gas savings must be achieved before any incentive is earned.

3. Calculation of incentive payments for gas savings greater than the threshold will be based on the net TRC benefits.

4. Recognizing that incremental energy savings become progressively more difficult to achieve, incentive payments will be earned according to the following schedule:

% of Annual Forecast GJ Savings	Before Tax Earnings as % of TRC Net Benefits
75% up to 100%	3%
100% and above	5%

5. DSM results (both positive and negative) from programs developed within the Utility but which at some point are moved outside the utility will be included in the DSM calculation where those program results are tracked by the Utility. This is consistent with the Company's goal of maximizing customer value in offering cost effective, competitive DSM services.

6. In order to maximize DSM efficiencies, BC Gas will be allowed to reallocate resources to modify existing programs, discontinue programs and develop new programs as the Company considers necessary. The Company will apply to the Commission for program changes where required.

7. A protocol for measuring DSM savings and TRC benefits needs to be established with the Commission and interested parties prior to the incentive mechanism taking effect.

8. The status of all DSM programs will be reviewed on a semi-annual basis with one of the reviews timed to coincide with the Annual Review of Service Quality Indicators.

9. The incentive mechanism will operate through the RSAM. The DSM Achievement Incentive operates outside of the Earnings Sharing Mechanism.

DSM Achievement Incentive Sample Calculations

Three cases are provided below representing the range of possible incentive payments for BC Gas achieving a minimum of 75% of forecast DSM gas savings.

Case A	Assuming:	75% of forecast gas savings achieved total TRC net benefits = $2,581,000
	Incentive = 3% of TRC net benefits (before tax) = $77,430	
Case B	Assuming:	100% of forecast gas savings achieved total TRC net benefits = $3,848,000
	Incentive = 5% of TRC net benefits (before tax) = $192,400	
Case C	Assuming:	110% of forecast gas savings achieved total TRC net benefits = $4,350,000
	Incentive = 5% of TRC net benefits (before tax) = $217,500	

Restructuring Deferral Account

A deferral account to record the costs incurred by BC Gas in restructuring its work force to achieve enhanced productivity is to be created and is to be effective upon the approval by the Commission of this settlement. The costs recorded in this deferral account will be recovered in customer rates. The deferral account will not exceed $3 million.

The amortization of this deferral account for restructuring costs will be no greater than $1 million for each year of the Term.

New Revenue Opportunities

The parties recognize that BC Gas should not be dis-incented from seeking legitimate new revenue opportunities which would serve to reduce future revenue deficiencies. To the extent such opportunities arise, but require expenditures greater than those arising from the formula, such revenues and expenditures will be addressed during the Annual Review each year.

Capital Expenditures

Capital expenditures for each year of the Term are established by class and by formula for certain of the classes. The classes are:

1. Mains - Recurring
2. Services - Recurring
3. Gas Measurement
4. Transmission Plant
5. System Improvements/Reinforcements
6. All Other Plant
7. Special Projects and CPCN's

Formulae for determining the expected capital expenditures for each year have been established for classes 1, 2, 3, 4, 5 and 6 as follows:

Note: the operation of the formulae for each class is shown for 1998 and 1999 and applies similarly to year 2000.

1. Mains - Recurring:

1998 Allowed Unit Cost =	Base Unit Cost x (1+ Inflation - Productivity)
1998 Allowed Cost =	1998 Allowed Unit Cost x Service Additions x 21.6 metres of main per Service Addition
Where:	Base Unit cost = $25.03/metre main Service Additions = 95.1% of forecast Customer Additions
1999 Allowed Unit Cost =	1998 Allowed Unit Cost x (1+ Inflation - Productivity)
1999 Allowed Cost =	1999 Allowed Unit Cost x Service Additions x 21.6 metres of main per Service Addition

2. Services:

1998 Allowed Unit Cost =	Base Unit cost x (1 + Inflation - Productivity)
1998 Allowed Cost =	1998 Allowed Unit Cost x Service Additions
Where:	Base Unit cost = $884/Service Addition Service Additions = 95.1% of forecast Customer Additions
1999 Allowed Unit Cost =	1998 Allowed Unit Cost x (1+ Inflation - Productivity)
1999 Allowed Cost =	1999 Allowed Unit Cost x Service Additions

3. Meters:

1998 Allowed Unit Cost =	Base Unit cost x (1 + Inflation - Productivity)
1998 Allowed Cost =	1998 Allowed Unit Cost x (Customer Additions + Meters Recalled)
Where:	Base Unit cost = $242/meter Customer Additions = forecast Customer Additions Meters Recalled = forecast of meters to be Recalled
1999 Allowed Unit Cost =	1998 Allowed Unit Cost x (1+ Inflation - Productivity)
1999 Allowed Cost =	1999 Allowed Unit Cost x (Customer Additions + Meters Recalled)

4. Transmission Plant:

1998 Allowed Unit Cost =	Base Unit cost x (1 + Inflation - Productivity)
1998 Allowed Cost =	1998 Allowed Unit Cost x Transmission System Forecast Peak Day Throughput

Where:	Base Unit cost = $439.50/10^3m^3$ Transmission System Forecast Peak Day Throughput = forecast Transmission System Forecast Peak Day Throughput productivity = 1%

1999 Allowed Unit Cost =	1998 Allowed Unit Cost x (1+ Inflation - Productivity)
1999 Allowed Cost =	1999 Allowed Unit Cost x Transmission System Forecast Peak Day Throughput

5. <u>System Improvements/Reinforcements:</u>

1998 Allowed Unit Cost =	Base Unit Cost x (1 + Inflation - Productivity)
1998 Allowed Cost =	1998 Allowed Unit Cost x Customers End of Year ("EOY")
Where:	Base Unit cost = $6.52/customer EOY Customer EOY = forecast end of year total customers productivity = 1%

1999 Allowed Unit Cost =	1998 Allowed Unit Cost x (1+ Inflation - Productivity)
1999 Allowed Cost =	1999 Allowed Unit Cost x Customers EOY

6. <u>All Other Plant:</u>

The Allowed Costs for All Other Plant for each year of the Term will be set with an aggregate base level of $29,317,000 adjusted for Inflation each year less Productivity.

1998 Allowed Cost =	$29,317,000 x (1+ Inflation - Productivity)
1999 Allowed Cost =	1998 Allowed Cost x (1+ Inflation - Productivity)

BC Gas has divided its capital expenditures into 4 categories. They are:

A. Mains, Meters and Services
B. System Integrity and Reliability
C. All Other Plant
D. CPCN's and Special Projects

The costs related to each category will be identified by the accounts prescribed by the BCUC Code of Accounts and the Company's sub-accounts as follows:

	BCUC Account	**BC Gas Sub-Account[1]**
Category A		
Distribution Plant - Service Installations	473	xxx excl. 62X[2]
Distribution Plant - Meter and Regulator Installations	474	xxx
Distribution Plant - New Mains	475	640
Distribution Plant - Main Installations General	475	649
Distribution Plant - Meters	478	xxx
Category B		
LNG	440 - 449	xxx
Transmission Plant	460 - 469	xxx
Distribution Plant - Main Corrosion Control	475	653 TS[3]
Distribution Plant - System Improvements	475	657/659
Distribution Plant - Gate and Regulator Stations	477	671
Distribution Plant - Telemetry	477	672 TS[3]
Category C	All other BCUC Capital accounts and BC Gas sub-accounts	
Category D	N/A	N/A

(1) xxx includes all BC Gas sub-accounts in the BCUC account
(2) Account 473-62X- Distribution Plant Renewals and Alteration
(3) TS refers to charges from Technical Services to these Accounts

<u>Special Projects and CPCN's</u>

Special Projects and Certificate of Public Convenience and Necessity ("CPCN") projects are capital projects which BC Gas foresees as being required within the Term, but have not been developed sufficiently (certain of such projects were identified and described in the Application, they include: Southern Crossing, Automated Meter Reading, Single Vendor System, Interior LNG Satellite Facility, Customer Information Systems, Coastal Facilities, SCADA, muster stations), or projects which are not foreseen but could be required, such as the relocation of an urban transmission pipeline. Such projects are subject to approval by the Commission through applications for Certificates of Public Convenience and Necessity. To the extent such applications are approved and the capital projects undertaken, the capital project will form part of the rate base of BC Gas in the year following the year in which the capital project is completed. BC Gas will be entitled to accrue AFUDC on the expenditures associated with the capital project until the capital project is part of rate base.

BC Gas will be entitled to include the prudently incurred total capital expenditures and AFUDC in rate base at the commencement of the year following completion of the capital project.

Capital Efficiency Mechanism

BC Gas should be incented to employ capital more efficiently. A capital efficiency mechanism will operate as set out below. The categories in respect of which the mechanism will operate are categories A and C as described above.

To the extent the actual unit costs for a year vary from the Allowed Unit Costs for Category A, this difference is to be multiplied by the actual number of units (e.g. in the case of Mains - Recurring it would be actual metres of main installed for the year). This amount, together with the difference between the actual and allowed capital expenditures for that year in Category C, will form the basis for an efficiency adjustment to the utility rate base. This adjustment will be an aggregate dollar sum (the "Capital Efficiency Adjustment") which will be added or subtracted from the utility rate base. This mechanism will operate similarly in the case of positive and negative variances in unit costs.

The Capital Efficiency Incentive Adjustment to rate base will be phased out over three years. More specifically, in the immediately following year 66.7% of this variance will be an adjustment to the utility rate base and 33.3% in the subsequent year. This phasing will apply to each year of the Term so that the effect of variances in the second and third year of the Term will continue beyond the Term, e.g., phasing of the year 2000 variances will occur through the year 2002. For examples of the effect of the Capital Efficiency Mechanism, see Cases A1, B1, C1 and D1 in the response to Item 6 of Information Request No. 1 of the Inland Industrial Group (Volume 2, Tab E6).

Depreciation and Amortization Expense

The depreciation rates for BC Gas currently approved by the Commission will continue. BC Gas has indicated that it intends to file a depreciation study. The Commission will consider the study and any changes arising upon receipt and consideration of the study and the recommendation for changes in rates, if any, applied for by the Company.

Deferral Accounts

The following deferral accounts are to be continued or created:

- Continuation of the debt interest deferral accounts.
- Continuation of the NGV conversion grants deferral account for 1998 - 2000 to be amortized over three years.
- Revenue requirement hearing costs to be amortized over three years.
- DSM expenditures for 1998 - 2000 to be amortized over three years.
- IRP costs for 1998 - 2000 to be amortized over three years.
- Deferral of property tax expense variances from forecast and amortized in the following year. 1996/1997 credits amortized as per Appendix A.
- BC Hydro DRIA - amortization as per Appendix A.
- DSM DRIA - amortization as per Appendix A.
- Continuation of Coastal Facilities relocation costs deferral account.

- April 29, 1997 application for Phase 2 of BC 21 Power Smart costs - $303,000.
- Continuation of RSAM and GCRA accounts as described above.
- Deferral of restructuring costs as described above.

Further details of the deferral accounts are found in Appendix A.

Overhead Capitalization

Pursuant to a term of the 1996 and 1997 Negotiated Settlement, BC Gas filed a study on its overheads capitalization policy. The study recommended a significant reduction in the capitalization ratio. The impact of this study was to reduce overhead capitalization from 22.5% to 10.27% as shown in Volume 1, Section C, Tab 9-02 Revised (line 20) of the Application.

The BC Gas study and proposal is accepted, however, the capitalization ratios will be limited to 20%, 20%, and 16% for the years 1998, 1999 and 2000 respectively based on total Gross O&M excluding DRIA. The Company may apply for additional reductions in overheads capitalized in subsequent revenue requirement filings.

Taxes

Changes in taxes and similar costs will continue to be flowed through to customers with variances recorded in deferral accounts and amortized in rates in the following year.

The methodology for determination of the level of taxes for each year of the Term will be determined in the manner as specified in the Application, Volume 1, Section C Tabs 10 and 13 as revised.

Other Cost of Service Categories

All other categories of the cost of service not specifically referred to above will be determined in the manner as specified in the Application, Volume 1 as revised.

Exogenous Factors

During the Term, the BC Gas cost of service will be adjusted for exogenous factors (positive or negative) which are beyond the full control of the utility including: judicial, legislative or administrative changes, orders and directions; changes in generally accepted accounting principles and rules, catastrophic events, bypass or other similar events imposed on BC Gas which are not reflected in the rates of BC Gas.

Earnings Sharing Mechanism

BC Gas will share equally with its customers earnings variances (positive or negative) between the authorized level of earnings as determined annually under this settlement and the actual earnings of the utility net of specific incentive programs; namely, the capital efficiency mechanism, the gas supply incentive plan and the DSM Achievement Incentive all of which will be considered to be non-utility income for the purposes of calculating the earnings of the utility.

The operation of the Earnings Sharing Mechanism is illustrated in Volume 1, Section C, Tab 15 of the Application.

Annual Reviews and Rate Adjustments

BC Gas will conduct an Annual Review of the operation of the settlement and rate adjustments prior to January 1 of each year of the Term with the Commission, its staff and interested parties. The Annual Review is a "proceeding" for purposes of participant cost awards. This process will provide the Commission and all interested parties an opportunity to remain informed about the activities of the Company. The Annual Review will attempt to obtain consensus on issues which must be decided by the Commission in advance of each fiscal year for the matters related to setting the rates for each year of the Term.

At the annual workshop to be held in November of each of the years 1998 through 1999, BC Gas will present projections for the year that is ending and forecasts for the next year. The projections for the year that is ending will include:

- projected utility volumes and revenues
- projected utility expenses
- projected year-end plant balances and other rate base information
- projected deferral account balances and amortization
- projected year-end customers and other cost driver information
- projected utility earnings.

Forecasts for the next year will include:

- forecast customer growth
- forecasts of cost drivers, such as peak day throughput
- forecast Inflation
- forecast utility volumes and revenues
- forecast utility expenses (revised allowed costs)
- forecast utility capital expenditures (revised allowed costs)
- forecast plant balances, deferral account balances and amortization to be included in rates.

Cost drivers for the next year will be updated to reflect the forecasts relating to the year. Cost drivers for the next year will also be updated for projected variances between actual customer growth in the past year and the customer growth that had been forecast for that year.

Opening plant balances and other rate base items for the next year will be adjusted to reflect projected variances which are not included in the capital efficiency mechanism discussed above.

Service quality results will also be reviewed at the Annual Review.

BC Gas proposes to commence its workshops in November of 1997. At that workshop forecasts for 1998 will be presented, together with the projected number of customers as of January 1, 1998 and projected plant balances and other rate base information as of January 1, 1998. Cost drivers for 1998 will be updated to reflect the forecasts for 1998. Rates for 1998 will be set by the Commission based on the projected opening rate base for 1998 and the forecasts for 1998 as agreed upon by the participants or as subsequently determined by the Commission.

Prior to each annual workshop, BC Gas will provide interested parties and the Commission advance information regarding the projections and forecasts to be presented by BC Gas at the workshop. This should be done 3 weeks prior to the workshop to allow parties to submit information requests and receive responses prior to the workshops.

In regard to projected year-end earnings, projected year end capital unit costs related to capital incentives presented for rate-making purposes in the November workshop BC Gas will provide an update in April or May once actual results have been determined and adjustments will be made at the following year end. Incentives will be trued up to the actual results at that time.

Service Quality Indicators

Principle:

Maintenance of existing high levels of service quality is an important feature of this Settlement. However, it is recognized that variance in these statistics may occur due to random events or events beyond the full control of BC Gas.

Process:

- Service Quality Indicators will be reviewed at the Annual Review in November of each year.

- Participants will be given an opportunity to argue whether a deviation from the benchmark for any of the Service Quality Indicators is significant enough to establish that service quality is deteriorating generally or in specific areas.

- For those concerns which are not resolved at the review, participants will retain the option to make submissions to the Commission that it should limit the payments which BC Gas might otherwise earn from the financial incentives in this Settlement.

Service Quality Indicators:

1. Response time to emergency calls[1].
2. Response time for answering service centre calls by a person.
3. Leaks per kilometre of distribution mains due to system deterioration.
4. Transmission system annual reportable incidents.
5. Number of third party distribution system damage incidents per 1000 housing starts[2].

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[1] Applies to Coastal region only. Data for 1994 and 1995 not available. Measure for Interior region will be determined at a later date.
[2] Data for 1994 is not available. Initial benchmark will be set using 2 years of data.

Annual Evaluation:

- Unless otherwise indicated, *benchmarks* will be calculated as the rolling average of the three years prior to the most current year; *performance indicators* will be calculated as the rolling average of the most current year plus the past two years.

- Each performance indicator will be evaluated on its own merits and a material deviation from the benchmark for any single performance indicator is sufficient basis to argue service quality deterioration and the need to limit payments to BC Gas.

- Each performance indicator will be given equal weight.

- The onus of establishing that a benchmark has been met or why it is reasonable that it was not met rests with the utility.

- Interested parties should have access to the service quality evaluation prior to the Annual Review.

- Any party may argue that the benchmarks need to be modified

Appendix A

1998 - 2002 Revenue Requirements Settlement

Illustrative Rate Impacts Summary

BC GAS UTILITY LTD.
SUMMARY
FOR THE YEARS 1998 TO 2000
($000)

APPENDIX A
1998-2000 SETTLEMENT
ILLUSTRATIVE RATE IMPACTS
SUMMARY

Particulars (1)	Volume 1 (Rev.) (2)	Difference (3)	1998-2000 Settlement (4)
1998			
Rate Base	$ 1,581,623	$ (12,734)	$ 1,568,889
Revenue Requirement	$ 24,448	$ (17,552)	$ 6,896
% Gross Margin Increase	6.37%	-4.57%	1.80%
Gross Margin (incl. Increase)	$ 408,468	$ (17,552)	$ 390,916
Operation and Maintenance			
Gross O&M excl. BC Hydro Costs	$ 136,057	$ (2,273)	$ 133,784
O&M Expense (Net)	$ 133,335	$ (16,244)	$ 117,091
Plant Additions			
- Capital Expenditures	$ 93,474	$ (8,782)	$ 84,692
- Overheads Capitalized	15,075	13,792	28,867
- All Other (WIP etc.)	2,445	0	2,445
Total	$ 110,994	$ 5,010	$ 116,004
1999			
Rate Base	$ 1,635,694	$ (4,125)	$ 1,631,569
Revenue Requirement	$ 14,278	$ (6,570)	$ 7,708
% Gross Margin Increase	3.44%	-1.50%	1.94%
Gross Margin (incl. Increase)	$ 429,512	$ (24,421)	$ 405,091
Operation and Maintenance			
Gross O&M excl. BC Hydro Costs	$ 139,981	$ (4,638)	$ 135,343
O&M Expense (Net)	$ 137,133	$ (18,696)	$ 118,437
Plant Additions			
- Capital Expenditures	$ 95,829	$ (9,241)	$ 86,588
- Overheads Capitalized	15,510	13,693	29,203
- All Other (WIP etc.)	8,420	0	8,420
Total	$ 119,759	$ 4,452	$ 124,211
2000			
Rate Base	$ 1,703,373	$ (16,436)	$ 1,686,937
Revenue Requirement	$ 11,984	$ (3,961)	$ 8,023
% Gross Margin Increase	2.73%	-0.79%	1.94%
Gross Margin (incl. Increase)	$ 450,229	$ (28,891)	$ 421,338
Operation and Maintenance			
Gross O&M excl. BC Hydro Costs	$ 144,106	$ (8,468)	$ 135,638
O&M Expense (Net)	$ 141,126	$ (16,581)	$ 124,545
Plant Additions			
- Capital Expenditures	$ 135,013	$ (47,670)	$ 87,343
- Overheads Capitalized	15,967	7,446	23,413
- All Other(WIP etc.)	140	0	140
Total	$ 151,120	$ (40,224)	$ 110,896

BC GAS UTILITY LTD.

SUMMARY OF RATE INCREASE REQUIRED
FOR THE YEARS ENDED DECEMBER 31, 1998 AND 1999
($000)

APPENDIX A
1998 - 2000 SETTLEMENT
ILLUSTRATIVE RATE IMPACTS
PAGE 01-01

	1998				1999			
	--- Captive ---				--- Captive ---			
	Core	Non-Core	Non-Captive	Total	Core	Non-Core	Non Captive	Total
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
RATE INCREASE REQUIRED								
Gas Sales and Transportation Revenue,								
At Prior Year's Rates	$721,248	$33,574	$15,139	$769,961	$742,055	$33,520	$15,108	$790,683
Add - Other Revenue Related to Burrard								
Thermal / Centra BC (PCEC)	0	336	8,806	9,142	0	336	8,888	9,224
Total Revenue	721,248	33,910	23,945	779,103	742,055	33,856	23,996	799,907
Less - Cost of Gas	(376,727)	(6,192)	(12,164)	(395,083)	(383,994)	(6,366)	(12,164)	(402,524)
Gross Margin	$344,521	$27,718	$11,781	$384,020	$358,061	$27,490	$11,832	$397,383
Revenue Deficiency-Volume 1 (Rev)	$22,628	$1,820	$0	$24,448	$13,260	$1,018	$0	$14,278
Difference	(16,245)	(1,307)	0	(17,552)	(6,102)	(468)	0	(6,570)
Revenue Deficiency								
- 1998-2000 Settlement	6,383	513	0	6,896	7,158	550	0	7,708
Refund of Deferred Gas Cost								
Credits (GCRA)	0	0	0	0	0	0	0	0
	$6,383	$513	$0	$6,896	$7,158	$550	$0	$7,708
Rate Increase as a % of Gross Margin	1.85%	1.85%	0.00%	1.80%	2.00%	2.00%	0.00%	1.94%
Rate Increase as a % of Total Revenue	0.88%	1.51%	0.00%	0.89%	0.96%	1.62%	0. 00%	0.96%

2000

Particulars (1)	----- Captive ---- Core (2)	Non-Core (3)	Non-Captive (4)	Total (5)
RATE INCREASE REQUIRED				
Gas Sales and Transportation Revenue, At Prior Year's Rates	$765,421	$34,282	$15,082	$814,785
Add - Other Revenue Related to Burrard Thermal / Centra BC (PCEC)	0	336	8,885	9,221
Total Revenue	765,421	34,618	23,967	824,006
Less - Cost of Gas	(392,051)	(6,476)	(12,164)	(410,691)
Gross Margin	$373,370	$28,142	$11,803	$413,315
Revenue Deficiency - Volume 1 (Rev.)	$11,144	$840	$0	$11,984
Difference	(3,683)	(278)	0	(3,961)
Revenue Deficiency - 1998-2000 Settlement	7,461	562	0	8,023
Refund of Deferred Gas Cost Credits (GCRA)	0	0	0	0
	$7,461	$562	$0	$8,023
Rate Increase as a % of Gross Margin	2.00%	2.00%	0.00%	1.94%
Rate Increase as a % of Total Revenue	0.97%	1.62%	0.00%	0,97%

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Description (1)	1998 Present Rates (2)	1998 Adj (3)	1998 Revised Rates (4)	1999 1998 Rates (5)	1999 Adj (6)	1999 Revised Rates (7)	2000 1999 Rates (8)	2000 Adj (9)	2000 Revised Rates (10)
Plant in Service, Beginning	$1,842,973	$0	$1,842,973	$1,949,177	$0	$1,949,177	$2,063,288	$0	$2,063,288
Additions	116,004	0	116,004	124 211	0	124 211	110 896	0	110,896
Disposals	(9,800)	0	(9,800)	(10,100)	0	(10,100)	(10,400)	0	(10,400)
Plant in Service, Ending	1,949,177	0	1,949,177	2,063,288	0	2,063,288	2,163,784	0	2,163,784
Add - Intangible Plant	967	0	967	967	0	967	967	0	967
	1,950,144	0	1,950,144	2,064,255	0	2,064,255	2,164,751	0	2,164,751
Contributions In Aid of Construction	(73,964)	0	(73,964)	(87,518)	0	(87,518)	(102,314)	0	(102,314)
Less - Accumulated Depreciation	(314,089)	0	(314,089)	(357,976)	0	(357,976)	(405,567)	0	(405,567)
Net Plant in Service, Ending	$1,562,091	$0	$1,562,091	$1,618,761	$0	$1,618,761	$1,656,870	$0	$1,656,870
Net Plant in Service, Beginning	$1,508,239	$0	$1,508,239	$1,562,091	$0	$1,562,091	$1,618,761	$0	$1,618,761
Net Plant in Service, Mid-Year	$1,535,165	$0	$1,535,165	$1,590,426	$0	$1,590,426	$1,637,816	$0	$1,637,816
Adjustment to 13-Month Average	0	0	0	0	0	0	0		0
Construction Advances	(3,114)	0	(3,114)	(2,336)	0	(2,336)	(1,557)	0	(1,557)
Work in Progress, No AFUDC	4,048	0	4,048	4 333	0	4,333	3,833	0	3,833
Unamortized Deferred Charges	(7,215)	0	(7,215)	(1 384)	0	(1,384)	4,167	0	4,167
Cash Working Capital	10,024	71	10,095	10,401	(106)	10,295	10,881	40	10,921
Other Working Capital	29,910	0	29,910	30,235	0	30,235	31,757	0	31,757
Utility Rate Base	$1,568,818	$71	$1,568,889	$1,631,675	(106)	$1,631,569	$1,686,897	40	$1,686,937

UTILITY INCOME AND EARNED RETURN
FOR THE YEARS ENDED DECEMBER 31, 1998, 1999 AND 2000
($000)

Particulars	1998 Present Rates	1998 -Revised Rates- Revised Revenue	1998 -Revised Rates- Total	1999 1998 Rates	1999 -Revised Rates- Revised Revenue	1999 -Revised Rates- Total	2000 1999 Rates	2000 -Revised Rates- Revised Revenue	2000 -Revised Rates- Total
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
ENERGY VOLUMES (TJ)									
Sales	158,624	0	158,624	161,357	0	161,357	164,379	0	164,379
Transportation	80,626	0	80,626	79,741	0	79,741	80,616	0	80,616
	239,250	0	239,250	241,098	0	241,098	244,995	0	244,995
Average Rate per GJ									
Sales	$4.680		$4.720	$4.731		$4.776	$4.788		$4.833
Transportation	$0.343		$0.348	$0.342		$0.348	$0.345		$0.351
Average	$3.218		$3.247	$3.280		$3.311	$3.326		$3.358
UTILITY REVENUE									
Sales - Present Rates	$742,344	$0	$742,344	$763,426	$0	$763,426	$786,984	$0	$786,984
- Increase	0	6,436	6,436	0	7,220	7,220	0	7,526	7,526
Transportation									
- Present Rates	27,617	0	27,617	27,257	0	27,257	27,801	0	27,801
- Increase	0	460	460	0	489	489	0	502	502
Total	769,961	6,896	776,857	790,683	7,708	798,391	814,785	8,023	822,808
Cost of Gas Sold									
(Including Gas Lost)	395,083	0	395,083	402,524	0	402,524	410,691	0	410,691
Gross Margin	374,878	6,896	381,774	388,159	7,708	395,867	404,094	8,023	412,117
Restructuring Costs Amort.	555	0	555	555	0	555	555	0	555
Operation and Maintenance	117,091	0	117,091	118,437	0	118,437	124,545	0	124,545
Vehicle and FIS Leases	2,269	0	2,269	2,309	0	2,309	2,346	0	2,346
Property and Sundry Taxes	31,210	0	31,210	32,227	(1)	32,226	34,577	0	34,577
Depreciation and Amortization	54,904	0	54,904	58,799	0	58,799	61,801	0	61,801
Other Operating Revenue	(14,169)	0	(14,169)	(14,399)	0	(14,399)	(14,545)	0	(14,545)
	191,860	0	191,860	197,928	(1)	197,927	209,279	0	209,279
Utility Income Before Taxes	183,018	6,896	189,914	190,231	7,709	197,940	194,815	8,023	202,838
Income Taxes	49,878	3,072	52,950	53,054	3,429	56,483	53,693	3,562	57,255
EARNED RETURN	$133,140	3,824	$136,964	$137,177	4,280	$141,457	$141,122	$4,461	$145,583
UTILITY RATE BASE	$1,568,818	$71	$1,568,889	$1,631,675	($106)	1,631,569	1,686,897	$40	1,686,937
RATE OF RETURN ON UTILITY RATE BASE	8.49%		8.73%	8.41%		8.67%	8.37%		8.63%

INCOME TAXES / REVENUE DEFICIENCY
FOR THE YEARS ENDED DECEMBER 31, 1998, 1999 AND 2000
($000)

Particulars	Present Rates	1998 -Revised Rates- Revised Revenue	Total	1998 Rates	1999 -Revised Rates- Revised Revenue	Total	1999 Rates	2000 -Revised Rates- Revised Revenue	Total
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
CALCULATION OF INCOME TAXES									
Earned Return	$133 140	$3,824	$136,964	$137,177	$4,280	$141,457	$141,122	$4,461	$145,583
Deduct -Interest on Debt	(73,711)	5	(73,706)	(77,441)	(4)	(77,445)	(84,252)	(17)	(84,269)
Add- Non-Tax Ded. Expense (Net)	4,435	0	4,435	5,317	0	5,317	4,315	0	4,315
Accounting Income After Tax	63,864	3,829	67,693	65,053	4,276	69,329	61,185	4,444	65,629
Add (Deduct) - Timing Differences	(9,757)	0	(9,757)	(7,309)	0	(7,309)	(2,875)	0	(2,875)
Add - Large Corporation Tax	2,440	(76)	2,364	2,508	(86)	2,422	2,597	(90)	2,507
Taxable Income After Tax	$56,547	$3,753	$60,300	$60,252	$4,190	$64,442	$60,907	$4,354	$65,261
Income Tax Rate(Current Tax)	45.620%	45.620%	45.620%	45.620%	45.620%	45.620%	45.620%	45.620%	45.620%
1 - Current Income Tax Rate	54.380%	54.380%	54.380%	54.380%	54.380%	54.380%	54.380%	54.380%	54.380%
Taxable Income (L10 : L14)	$103,985	$6,901	$110,886	$110,798	$7,705	$118,503	$112,003	$8,006	$120,009
Income Tax-Current (L18xL13)	$47,438	$3,148	$50,586	$50,546	$3,515	$54,061	$51,096	$3,652	$54,748
- Large Corporation Tax	2,440	(76)	2,364	2,508	(86)	2,422	2,597	(90)	2,507
Total	$49,878	$3,072	$52,950	$53,054	$3,429	$56,483	$53,693	$3,562	$57,255
REVENUE DEFICIENCY									
Earned Return		$3,824	$136,964		$4,280	$141,457		$4,461	$145,583
Add - Income Taxes		3,072	52,950		3,429	56,483		3,562	57,255
Deduct - Utility Income Before Taxes, Present Rates		0	(183,018)		0	(190,231)		0	(194,815)
Corporate Capital Tax		0	0		(1)	(1)		0	0
Deficiency After Corporate Capital Tax		$6,896	$6,896		$7,708	$7,708		$8,023	$8,023

RETURN ON CAPITAL
FOR THE YEARS ENDED DECEMBER 31, 1998, 1999 AND 2000
($000)

Particulars	Reference	---- Capitalization ---- Amount	%	Embedded Cost	Average Cost Component	Earned Return
1998 PRESENT RATES						
Long-Term Debt		$692,562	44.15%	9.420X	4.16X	
Unfunded Debt		211,701	13.49%	4.000%	0.54%	
Preference Shares		146,845	9.36%	6.995%	0.65%	
Common Equity		517,710	33.00%	9.515%	3.14%	
		$1,568,818	100.00%		8.49%	
1998 REVISED RATES						
Long-Term Debt		$692,562	44.14%	9.420%	4.16%	$65,239
Unfunded Debt	$211,701					
Adjustment, Revised Rates	48	211,749	13.50%	4.000%	0.54%	8,470
Preference Shares		146,845	9.36%	6.995%	0.65%	10,272
Common Equity		517,733	33.00%	10.250%	3.38%	53,068
		$1,568,889	100.00%		8.73%	$137,049
1999 AT 1998 RATES						
Long-Term Debt		$734 940	45.04%	9.288%	4.18%	
Unfunded Debt		229,546	14.07%	4.000%	0.56%	
Preference Shares		128,736	7.89%	6.946%	0.55%	
Common Equity		538,453	33.00%	9.455%	3.12%	
		$1,631,675	100.00%		8.41%	
1999 REVISED RATES						
Long-Term Debt		$734,940	45.05%	9.288%	4.18%	$68,261
Unfunded Debt	$229,546					
Adjustment, Revised Rates	(71)	229,475	14.06%	4.000%	0.56%	9,179
Preference Shares		128,736	7.89%	6.946%	0.55%	8,942
Common Equity		538,418	33.00%	10.250%	3.38%	55,188
		$1,631,569	100.00%		8.67%	$141,570

2000 AT 1999 RATES						
Long-Term Debt		$828,322	49.10%	9.016%	4.43%	
Unfunded Debt		239 399	14.19%	4.000%	0 57%	
Preference Shares		62 500	3.71%	6.631%	0 25%	
Common Equity		556,676	33.00%	9.455%	3.12%	
		$1,686,897	100.00%		8.37%	
2000 REVISED RATES						
Long-Term Debt		$828,322	49.11%	9.016%	4.43%	$74,682
Unfunded Debt	$239,399					
Adjustment, Revised Rates	27	239,426	14.19%	4.000%	0.57%	9,577
Preference Shares		62,500	3.70%	6.631%	0.25%	4,144
Common Equity		556,689	33.00%	10.250%	3.38%	57,061
		$1,686,937	100.00%		8.63%	$145,464

BC GAS UTILITY LTD
TARGET COSTS - CAPITAL EXPENDITURE SUMMARY
FOR THE YEARS ENDING DECEMBER 31, 1998 TO 2000
($000)

Particulars (1)	Base Cost (2)	Target Costs 1998 (3)	Target Costs 1999 (4)	Target Costs 2000 (5)
SUMMARY - TOTAL COST				
CATEGORY:				
A: MAINS, SERVICES & METERS	$35,204	$36,246	$37,652	$38,445
B: SYSTEM INTEGRITY AND RELIABILITY	18,545	18,805	18,948	18,850
C: ALL OTHER PLANT	29,317	29,641	29,988	30,048
TOTAL - CATEGORIES A, B & C	83,066	84,692	86,588	87,343
D: SPECIAL PROJECTS 2300	0	0	0	0
8400	0	0	0	0
MISC.	0	0	0	0
TOTAL CAPITAL EXPENDITURES	83,066	84,692	86,588	87,343
TOTAL PER 1998-2002 VOL. 1, PAGE 03-04 (REV)	89,908	93,474	95,829	135,013
INCREASE (DECREASE)	($6,842)	($8,782)	($9,241)	($47,670)
TOTAL CAPITAL EXPENDITURES - REAL ($1997)	$83,066	$83,853	$84,882	$84,774

CAPITAL EXPENDITURE/PLANT ADDITIONS SUMMARY 1998 - 2000 SETTLEMENT

BC GAS UTILITY LTD. ILLUSTRATIVE RATE IMPACTS

($000) PAGE 03-05

Particulars	Base Cost	Target Costs 1998	1999	2000
(1)	(2)	(3)	(4)	(5)
CAPITAL EXPENDITURES				
A: MAINS, SERVICES & METERS	$35,204	$36,246	$37,652	$38,445
B: SYSTEM INTEGRITY AND RELIABILITY	18,545	18,805	18,948	18,850
C: ALL OTHER PLANT	29,317	29,641	29,988	30,048
D: SPECIAL PROJECTS	0	0	0	0
TOTAL CAPITAL EXPENDITURES	83,066	84,692	86,588	87,343
WORK IN PROGRESS				
Add - Opening WIP		16,100	15,205	8,380
Less - Closing WIP		(15,205)	(8,380)	(9,770)
Add - AFUDC		1,550	1,595	1,530
Add - O'H Capitalized		28,867	29,203	23,413
SUBTOTAL - PLANT ADDITIONS		116,004	124,211	110,896
Add - 1996 and 1997 CPCN's		6,618		.
TOTAL PLANT ADDITIONS		122,622	124,211	110,896
TOTAL PER 1998 - 2002 VOL. 1, PAGE 03-05 (REV.)		117,612	119,759	151,120
INCREASE (DECREASE)		$5,010	$4,452	($40,224)

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDED DECEMBER 31, 1998
($000)

Particulars	Account	Forecast Balance 12/31/97	Gross Additions	Less- Taxes	Net Additions	Amortization Expense	Amortization Other	Balance 12/31/98	Mid-Year Average 1998
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Deferred Interest	#179-008	$0	$0	$0	$0	$0	$0	$0	$0
Market Rebate Incentive									
- Water Heater Grants	#179-052	402	0	0	0	(100)	0	302	352
- Commercial & Multi-Family	#179-013	103	0	0	0	(55)	0	48	75
NGV Conversion Grants	#179-018	20	0	0	0	(20)	0	0	10
NGV Conversion Grants 1996-1997		1,534	0	0	0	(527)	0	1,007	1,271
NGV Conversion Grants 1998-2002		0	1,500	(668)	832	0	0	832	416
Local Gas Development	#179-053	2,908	0	(90)	(90)	(564)	0	2,254	2,581
Fraser Valley Gas Exploration	#179-092	457	0	0	0	(91)	0	366	411
Revenue Req. Hearing-1998-2002	179-141	133	0	0	0	(44)	0	89	111
Demand Side Management G-69-93	179-063	45	0	0	0	(33)	0	12	28
Demand Side Management 1996-97		327	0	0	0	(110)	0	217	272
Demand Side Management 1998-2002		0	1,585	(705)	880	0	0	880	440
Integrated Resource Plan G-69-93	179-064	133	0	0	0	(77)	0	56	94
Integrated Resource Plan G-60-94		147	0	0	0	(49)	0	98	123
Integrated Resource Plan 1996-97		108	0	0	0	(36)	0	72	90
Integrated Resource Plan 1998-2002		0	100	(45)	55	0	0	55	28
Residential Thermostat Program	#179-109	30	0	0	0	(11)	0	19	24
Property Tax Deferral	#179-062	(890)	0	0	0	0	0	(890)	(890)
Westar Receivable	#179-069	134	0	0	0	(27)	0	107	121

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDED DECEMBER 31, 1998
($000)

Particulars	Account	Forecast Balance 12/31/97	Gross Additions	Less-Taxes	Net Additions	Amortization Expense	Amortization Other	Balance 12/31/98	Mid-Year Average 1998
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
G.C.R.A.	#179-088	(13,500)	0	0	0	0	4,500	(9,000)	(11,250)
G.C.R.A. Interest	#179-188	0	0	0	0	0	0	0	0
Offsystem Sales Coord. Center	179-120	23	0	0	0	(10)	0	13	18
Revelstoke Propane Cost	#279-024	293	0	0	0	0	(293)	0	147
B.C. Hydro DRIA	#179-144	(823)	0	0	0	0	0	(823)	(823)
DSM DRIA	#179-142	(489)	0	0	0	0	0	(489)	(489)
Recovery of Non-Utility Service	#279-063	(98)	0	0	0	98	0	0	(49)
RSAM	#179-089	(7,500)	0	0	0	0	2,500	(5,000)	(6,250)
NGV B.C. Transit Grants	#179-105	461	0	0	0	(159)	0	302	382
BC21 Power Smart Program	#179-119	444	0	0	0	(222)	0	222	333
BC21 Power Smart Phase 2		168	0	0	0	(34)	0	134	151
Coastal Facilities (#C-6-95)									
- Relocation		2,387	1,049	(467)	582	(686)	0	2,283	2,335
- Lochburn NBV Amortization		1,108	0	0	0	(369)	0	739	924
- Fraser Valley NBV Amortization		878	0	0	0	(176)	0	702	790
Organizational Restructuring	#179-132	480	0	0	0	(96)	0	384	432
Non-Core Margin Deferral	#179-135	214	0	0	0	0	(214)	0	107
Main Extension Hearing Costs	#179-138	18	0	0	0	(18)	0	0	9
1995 IRP Participant A~ards	#179-140	7	0	0	0	(7)	0	0	4
Gain on Sale of Kamloops Property	279-001	(193)	0	0	0	193	0	0	(97)
Restructuring Costs		0	3,000	(1,335)	1,665	(555)	0	1,110	555
Total Deferred Charges for Rate Base		($10,531)	$7,234	($3,310)	3,924	($3,785)	$6,493	($3,899)	($7,215)
		=======	=====	=====	=====	=====	=====	=======	=====

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDED DECEMBER 31, 1999
($000)

Particulars	Account	Forecast Balance 12/31/98	Gross Additions	Less- Taxes	Net Additions	Amortization Expense	Amortization Other	Balance 12/31/99	Mid-Year Average 1999
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Deferred Interest	#179-008	$0	$0	$0	$0	$0	$0	$0	$0
Market Rebate Incentive									
- Water Heater Grants	#179-052	302	0	0	0	(100)	0	202	252
- Commercial & Multi-Family	179-013	48	0	0	0	(48)	0	0	24
NGV Conversion Grants	#179-018	0	0	0	0	0	0	0	0
NGV Conversion Grants	1996-1997	1,007	0	0	0	(527)	0	480	743
NGV Conversion Grants	1998-2002	832	1,500	(668)	832	(277)	0	1,387	1,109
Local Gas Development	#179-053	2,254	0	(81)	(81)	(544)	0	1,629	1,942
Fraser Valley Gas Exploration	179-092	366	0	0	0	(91)	0	275	320
Revenue Req. Hearing-1998-2002	179-141	89	0	0	0	(44)	0	45	67
Demand Side Management G-69-93	179-063	12	0	0	0	(12)	0	0	6
Demand Side Management 1996-97		217	0	0	0	(109)	0	108	163
Demand Side Management 1998-2002		880	1,585	(705)	880	(293)	0	1,467	1,174
Integrated Resource Plan G-69-93	179-064	56	0	0	0	(56)	0	0	28
Integrated Resource Plan #G-60-94		98	0	0	0	(49)	0	49	73
Integrated Resource Plan 1996-97		72	0	0	0	(36)	0	36	54
Integrated Resource Plan 1998-2002		55	100	(45)	55	(18)	0	92	74
Residential Thermostat Program	#179-109	19	0	0	0	(11)	0	8	14
Property Tax Deferral	#179-062	(890)	0	0	0	0	429	(461)	(676)
Westar Receivable	#179-069	107	0	0	0	(26)	0	81	93

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION 1998 - 2000 SETTLEMENT
FOR THE YEAR ENDED DECEMBER 31, 1999 1999
($000) PAGE 03-11.4

Particulars	Account	Forecast Balance 12/31/98	Gross Additions	Less- Taxes	Net Additions	Amortization Expense	Amortization Other	Balance 12/31/99	Mid-Year Average 1999
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
G.C.R.A.	#179-088	(9,000)	0	0	0	0	4,500	(4,500)	(6,750)
G.C.R.A. Interest	#179-188	0	0	0	0	0	0	0	0
Offsystem Sales Coor. Center	#179-120	13	0	0	0	(13)	0	0	7
Revelstoke Propane Cost	#279-024	0	0	0	0	0	0	0	0
B.C. Hydro DRIA	#179-144	(823)	0	0	0	0	0	(823)	(823)
DSM DRIA	#179-142	(489)	0	0	0	0	0	(489)	(489)
Recovery of Non-Utility Service	279-063	0	0	0	0	0	0	0	0
RSAM	#179-089	(5,000)	0	0	0	0	2,500	(2,500)	(3,750)
NGV B.C. Transit Grants	#179-105	302	0	0	0	(159)	0	143	223
BC21 Power Smart Program	#179-119	222	0	0	0	(222)	0	0	111
BC21 Power Smart Phase 2		134	0	0	0	(34)	0	100	117
Coastal Facilities (#C-6-95)									
- Relocation		2,283	1,049	(467)	582	(802)	0	2,063	2,173
- Lochburn NBV Amortization		739	0	0	0	(369)	0	370	555
- Fraser Valley NBV Amortization		702	0	0	0	(176)	0	526	614
Organizational Restructuring	#179-132	384	0	0	0	(96)	0	288	336
Non-Core Margin Deferral	#179-135	0	0	0	0	0	0	0	0
Main Extension Hearing Costs	#179-138	0	0	0	0	0	0	0	0
1995 IRP Participant Awards	#179-140	0	0	0	0	0	0	0	0
Gain on Sale of Kamloops Property	#279-001	0	0	0	0	0	0	0	0
Restructuring Costs		1,110	0	0	0	(555)	0	555	833
Total Deferred Charges for Rate Base		($3,899)	$4,234	($1,966)	2,268	($4,667)	$7,429	$1,131	($1,384)

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION 1998 - 2000 SETTLEMENT
FOR THE YEAR ENDED DECEMBER 31, 2000 2000
($000)

Particulars (1)	Account (2)	Forecast Balance 12/31/99 (3)	Gross Additions (4)	Less-Taxes (5)	Net Additions (6)	Amortization Expense (7)	Amortization Other (8)	Balance 12/31/00 (9)	Mid-Year Average 2000 (10)
Deferred Interest	#179-008	$0	$0	$0	$0	$0	$0	$0	$0
Market Rebate Incentive									
- Water Heater Grants	#179-052	202	0	0	0	(100)	0	102	152
- Commercial & Multi-Family	179-013	0	0	0	0	(42)	0	(42)	(21)
NGV Conversion Grants	#179-018	0	0	0	0	0	0	0	0
NGV Conversion Grants	1996-1997	480	0	0	0	(480)	0	0	240
NGV Conversion Grants	1998-2002	1,387	1,500	(668)	832	(555)	0	1,664	1,526
Local Gas Development	#179-053	1,629	0	(73)	(73)	(520)	0	1,036	1,332
Fraser Valley Gas Exploration	179-092	275	0	0	0	(91)	0	184	230
Revenue Req. Hearing-1998-2002	179-141	45	0	0	0	(45)	0	0	23
Demand Side Management G-69-93	179-063	0	0	0	0	0	0	0	0
Demand Side Management 1996-97		108	0	0	0	(108)	0	0	54
Demand Side Management 1998-2002		1,467	1,585	(705)	880	(587)	0	1,760	1,613
Integrated Resource Plan G-69-93	179-064	0	0	0	0	0	0	0	0
Integrated Resource Plan #G-60-94		49	0	0	0	(49)	0	0	25
Integrated Resource Plan 1996-97		36	0	0	0	(36)	0	0	18
Integrated Resource Plan 1998-2002		92	100	(45)	55	(37)	0	110	100
Residential Thermostat Program	#179-109	8	0	0	0	(8)	0	0	4
Property Tax Deferral	#179-062	(461)	0	0	0	0	461	0	(231)
Westar Receivable	#179-069	81	0	0	0	(27)	0	54	68

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION   1998 - 2000 SETTLEMENT
FOR THE YEAR ENDED DECEMBER 31, 2000   2000
($000)   PAGE 03-11.6

Particulars (1)	Account (2)	Forecast Balance 12/31/99 (3)	Gross Additions (4)	Less- Taxes (5)	Net Additions (6)	Amortization Expense (7)	Amortization Other (8)	Balance 12/31/009 (9)	Mid-Year Average 2000 (10)
G.C.R.A.	#179-088	(4,500)	0	0	0	0	4,500	0	(2,250)
G.C.R.A. Interest	#179-188	0	0	0	0	0	0	0	0
Offsystem Sales Coor. Center	#179-120	0	0	0	0	0	0	0	0
Revelstoke Propane Cost	#279-024	0	0	0	0	0	0	0	0
B.C. Hydro DRIA	#179-144	(823)	0	0	0	823	0	0	(412)
DSM DRIA	#179-142	(489)	0	0	0	489	0	0	(245)
Recovery of Non-Utility Service	279-063	0	0	0	0	0	0	0	0
RSAM	#179-089	(2,500)	0	0	0	0	2,500	0	(1,250)
NGV B.C. Transit Grants	#179-105	143	0	0	0	(143)	0	0	71
BC21 Power Smart Program	#179-119	0	0	0	0	0	0	0	0
BC21 Power Smart Phase 2		100	0	0	0	(34)	0	66	83
Coastal Facilities (#C-6-95)									
- Relocation		2,063	1,049	(467)	582	(918)	0	1,727	1,895
- Lochburn NBV Amortization		370	0	0	0	(370)	0	0	185
- Fraser Valley NBV Amortization		526	0	0	0	(176)	0	350	438
Organizational Restructuring	#179-132	288	0	0	0	(96)	0	192	240
Non-Core Margin Deferral	#179-135	0	0	0	0	0	0	0	0
Main Extension Hearing Costs	#179-138	0	0	0	0	0	0	0	0
1995 IRP Participant Awards	#179-140	0	0	0	0	0	0	0	0
Gain on Sale of Kamloops Property	#279-001	0	0	0	0	0	0	0	0
Restructuring Costs		555	0	0	0	(555)	0	555	278
Total Deferred Charges for Rate Base		($1,131)	$4,234	($1,958)	2,276	($3,665)	$7,461	$7,203	($4,167)
		======	======	======	=====	======	======	======	======

OPERATING & MAINTENANCE EXPENSE
($000)

Particulars	Target Costs 1998	1999	2000
(1)	(2)	(3)	(4)
Cost Drivers / Escalators			
Average No. of Customers	734,710	750,609	767,317
Growth %	2.10%	2.16%	2.23%
Productivity Improvement Factor (PIF)	2.00%	2.00%	3.00%
Inflation (CPI)	1.00%	1.00%	1.00%
O&M (Gross)			
O&M	$133,784	$135 343	$135,638
BC Hydro Service Agreement	10,550	10 673	10,696
Total	144,334	146,016	146,334
DRIA's			
- DSM / IRP	1,624	1,624	1,624
- Other	-	-	-
	1,624	1,624	1,624
Total Gross O&M	145,958	147,640	147,958
O'H Capitalized	20.00%	20.00%	16.00%
O&M	28,867	29,203	23,413
BC Hydro Senvice Agreement			
DRIA's - DSM / IRP	-	-	-
- Other	-	-	-
Total O'H Capitalized	28,867	29,203	23,413
Total Per 1998 - 2002 Vol. 1, Page 09-02 (Rev)	15,075	15,510	15,967
Difference	13,792	13,693	7,446
O&M Expense (Net)			
O&M	115,467	116,813	122,921
DRIA's - DSM/IRP	1,624	1,624	1,624
- Other	-	-	-
Total O&M Expense	$117,091	$118,437	$124,545
Total per 1998-2002 Vol.1, Page 09-02 (Rev.)	$133,335	$137,133	$141,126
Difference	($16,244)	($18,696)	($16,581)

Appendix B

Commission Staff letter of July 15, 1997

BRITISH COLUMBIA UTILITIES COMMISSION

WILLIAM J. GRANT
EXECUTIVE DIRECTOR,
REGULATORY AFFAIRS & PLANNING

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, B.C. CANADA V6Z 2N3
TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

VIA FACSIMILE

July 15, 1997

Mr. Jim Quail
The British Columbia Public
Interest Advocacy Centre
815 - 815 West Hastings Street
Vancouver, B.C.
V6C 1B4

Dear Jim:

Re: BC Gas Utility Ltd.
Revenue Requirements Application

Thank you for your two letters of July 10, 1997 indicating your consent to the terms of the proposed settlement document along with the letter recording your interpretation of two of the provisions of the proposed settlement of this matter.

With respect to O&M productivity gains from capital projects the settlement document records the method for recognizing productivity at page 5. During our discussions of this matter we explored several examples including the Southern Crossing Project and the construction of a new operations building in the Lower Mainland.

In the case of the Southern Crossing Project the approval and construction of the pipeline would come into rate base the year following its completion. A number of impacts would be felt including funding of the rate base addition, changes to Westcoast or other upstream transportation suppliers, new gas supply options at hopefully more efficient prices, and the potential of third party revenues from the use of spare capacity in the pipeline. None of these components would affect the O&M productivity levels unless BC Gas were also able to obtain a direct O&M productivity improvement from the existence of this new capital edition. If that were to occur it would be available to assist BC Gas in meeting its O&M productivity targets during the remaining term of the three year agreement.

The completion of a new operations centre in the Lower Mainland is probably a better example of where some real O&M productivity might occur. In this case, BC Gas may seek approval and then build the new operations centre allowing it to sell parts of the Boundary/Lougheed property and relocate personnel from a number of leased premises. Presumably, there would also be some down sizing of space requirements at the downtown office. The effect would be that the new capital costs would flow into rate base the year following their completion and the proceeds of the sale of the Boundary/Lougheed property would reduce rate base. These changes would not affect the O&M productivity levels but the Company will likely obtain a number of efficiencies resulting from the more efficient housing of employees, the avoidance of travel, and such matters as the updating of equipment. These benefits are all available to assist the Company in meeting its O&M productivity targets for whatever remaining period exists in the three year settlement.

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A third potentially significant CPCN could be the completion of a new customer information system allowing consolidated billing and other links to the financial and work order systems within BC Gas. As with the other projects the capital costs related to the new system would come into rate base in the year following completion. At the same time the Unisys system would be retired from rate base and the billing contract with B.C. Hydro would be terminated. These changes would not effect the O&M productivity targets, but the existence of the new customer information systems would likely have a profound impact on BC Gas operations, allowing improved information and efficiencies in numerous O&M areas of the Company. All of these O&M benefits would assist the Company in meeting the O&M targets for the remaining period of the three year settlement.

I hope this assists by providing an assessment of three of the more significant capital projects which may come to realization late in the three year settlement horizon.

Yours truly,

Original signed by:

W.J. Grant

WJG/lm
cc: Mr. D.M. Masuhara, Vice President
Legal and Regulatory Affairs
BC Gas Utility Ltd.
Mr. David Bursey, Bull, Housser & Tupper
Mr. Chris Weafer, Owen Bird
Ms. Carol Reardon, Heenan Blaikie
Mr. Dave Newlands, Fording Coal,
c/o Pacific Western Energy Products and Services Inc
Mr. R. O'Callaghan, RT O'Callaghan & Associates Inc