IN THE MATTER OF the "Utilities Commission Act" S.B.C. 1980, Chapter 60

and

IN THE MATTER OF an Application by BC Gas Utility Ltd. To Amend its Schedule of Rates

1996 Rate Design

Volume 2

Application

JUNE 1996

BC Gas

BC GAS UTILITY LTD.

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1996 RATE DESIGN APPLICATION

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BC GAS LONG RUN INCREMENTAL COSTS

This long run incremental cost (LRIC) study estimates the costs associated with serving future gas demand resulting from new customers attaching to the BC Gas system as well as increased demand from existing customers.

1.0 CONCEPTS AND COMPONENTS

Incremental costs are one of the factors used to design customer rates. They measure the costs customers are expected to impose on the gas system over the long-term. The incremental costs presented here cover both the BC Gas distribution system as well as upstream gas supply costs.

Long run incremental cost estimates in this study are grouped into three components:

- Demand costs
- Commodity costs
- Customer costs

The following sections describe the elements and the procedures used in deriving cost estimates for each component. The final section provides a summary and conclusions.

2.0 DEMAND COSTS

The demand cost component consists of costs associated with transmission and distribution capacity on the BC Gas system and the fixed demand costs for gas supply.

2.1 DEMAND COSTS: TRANSMISSION AND DISTRIBUTION SYSTEM IMPROVEMENTS

System improvements include capacity additions to the BC Gas distribution and transmission system that accommodate the incremental load requirements of new and existing customers.

The incremental cost estimate of transmission capacity was derived from 20 year transmission plans for BC Gas. The present value of total forecast capital transmission expenditures over the 20 year forecast period was divided by the present value of forecast incremental system peak day demand over that same period. A capital recovery factor was applied to derive the annual transmission cost of capacity in $/peak day GJ. Overhead was added to account for those operation and maintenance expenditures capitalized into transmission costs. Derivation of incremental overhead rates is discussed in Section 5.

Estimates for the incremental cost of distribution capacity were derived from the BC Gas Five Year System Plan. The capital cost estimates for regions in the interior were adjusted to account for districts with incomplete Five Year Plans[1]. Only those projects in the System Plan that were required for meeting increases in capacity requirements, from increased loads due to new or existing customers, were used in the estimation. Replacement projects not associated with incremental requirements were not included in the analysis. The annual distribution cost of capacity was calculated in a similar manner to that used for transmission. Capital expenditures shown in the five year plan were averaged and applied to future years[2]. This extrapolation was required to provide distribution capital costs on a consistent basis with transmission capital costs and the peak day system forecast.

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[1] System planning budgets in the interior region were increased by 4.4% in each year, representing the portion of customers residing in areas where 5 year plans have yet to be completed.

[2] System planners at BC Gas indicate that this procedure produces a reasonable proxy of longer term capital project requirements to meet capacity demand growth.

Table 1 below shows the cost estimates for adding additional transmission and distribution capacity.

Table 1: Transmission and Distribution $1996 per Peak Day GJ		
	Total	Annual*
Transmission	$ 298	$ 35
Distribution	$ 410	$ 41
Total T&D	$ 708	$ 77

* Capacity Recovery Factor 10.31%

Total forecast transmission and distribution expenditures together with the associated peak day demand forecast for the BC Gas system are given in Table 2.

Table 2: Transmission & Distribution System Costs and Peak Day Demand Forecasts

	Capital Costs			Peak Day
	Transmission	Distribution ($millions)	Total	(TJ)
1996	5.7	9.1	14.8	1,174
1997	7.2	10.7	17.9	1,186
1998	-	3.9	3.9	1,213
1999	7.2	3.5	10.7	1,240
2000	-	10.3	10.3	1,265
2001	6.8	7.5	14.3	1,288
2002	-	7.5	7.5	1,311
2003	10.8	7.5	18.3	1,333
2004	5.9	7.5	13.4	1,354
2005	7.2	7.5	14.7	1,376
2006	-	7.5	7.5	1,397
2007	31.0	7.5	38.5	1,420
2008	-	7.5	7.5	1,437
2009	-	7.5	7.5	1,454
2010	41.2	7.5	48.7	1,470
2011	-	7.5	7.5	1,485
2012	14.0	7.5	21.5	1,501
2013	-	7.5	7.5	1,517
2014	-	7.5	7.5	1,533
2015	-	7.5	7.5	1,549

2.2 DEMAND COSTS: GAS SUPPLY

Incremental gas supply costs were determined using the company's Gas Supply Optimization Model (GSOM). Gas supply incremental costs were estimated by assuming that gas demand will be two percent greater than currently forecasted. This change in gas demand results in additional gas supply requirements, the cost of which is the incremental gas supply cost. GSOM selects available supply resources to meet forecast demand requirements. The available supply resources include contracts for various periods and amounts, space in underground storage facilities, and peaking facilities such as LNG. GSOM indicates that for an increase in load, with a system average load factor, the long term marginal supply source would be an annual base load supply contract.

The demand cost associated with gas supply was separated into two parts.

Most supply resource options chosen by GSOM can be thought of as serving a dual purpose - meeting peak day demands and meeting demand on non-peak days. Since the marginal resource selected by GSOM was long term base load contracts, a method for deriving a pure peak-related demand cost was required. To separate pure peak demand costs from the total fixed costs identified in GSOM, an LNG facility was chosen as a proxy for the cost of serving needle peak loads. The 2BCF LNG facility described in the 1995 BC Gas IRP has an associated peak day cost of $518/GJ/day. Applying a capital recovery factor results in an annual cost of capacity of approximately $53/GJ/day.

The fixed cost (demand charges) of meeting incremental load as determined by GSOM is $334/peak day GJ (levelized). When the cost for LNG peaking is subtracted, the residual demand component is:

$334 - $53 = $281 GJ/peak day
$281/364 days = $0.77/GJ (at 100% load factor).

This residual demand component is termed here the average demand.

3.0 COMMODITY COSTS

The variable gas supply cost was derived from the annual estimates produced by GSOM. The levelized commodity cost was estimated to be $0.95/GJ ($1996). The winter (November - March) commodity cost was estimated to be $1.08/GJ while the summer (April-October) was $0.70/GJ.

4.0 LONG RUN CUSTOMER CAPITAL COSTS

The costs of attaching additional customers to the gas distribution system includes one time capital expenditures for meter sets, services and mains. These costs can be attributed to specific customer rate classes on a per customer basis using data for typical customer attachments. Table 3 provides current estimates of customer capital costs for rates 1, 2 and 3.

The costs given in the table were developed by BC Gas distribution service engineers and represent typical costs associated with attaching customers in each class. Attachment costs for specific customers could vary substantially from these estimates. The costs shown for services and mains assume a ratio of 1.2 customers per service to account for multiple accounts from single services.

Table 3: Meter Set, Service Line and Main Costs per Customer $1996			
	Rate 1	Rate 2	Rate 3
Meter Set	$ 346	$ 477	$ 3,016
Service	$ 539	$ 539	$ 539
Main	$ 516	$ 516	$ 516
Overhead	$ 517	$ 566	$ 1,503
Total	$ 1,918	$ 2,098	$ 5,574
Annual Cost	$ 198	$ 216	$ 575

* Capital Recovery Factor 10.31%

Because seasonal and larger industrial customers comprise a heterogeneous group with wide cost variations and no readily identifiable typical customer, customer attachment cost estimates for these industrial customers are not meaningful.

An overhead rate was applied to the total direct costs in each rate class (see Section 5 for a discussion of overheads). It was assumed that future customer attachment costs for meters, services and mains will remain constant in real terms.

5.0 LONG RUN OPERATION AND MAINTENANCE COSTS

Incremental operation and maintenance (O&M) costs were determined using as a base the 1996 approved O&M budget from the 1996-1998 BC Gas Revenue Requirements Application. Incremental O&M costs associated with demand, commodity and customer components, shown in Table 4, were determined using the following approach.

Table 4: Operation & Maintenance Costs ($1996)	
Demand	
(1) Demand Related O&M	$ 11,790 ($000)
(2) System Peak Day (1996)	$ 1,174 (TJ)
(3) (1)/(2)	**$ 10.04 ($/peak day GJ)**
Commodity	
(1) Commodity Related O&M	$ 1,178 ($000)
(2) Total System Throughput	$ 232,443 (TJ)
(3) (1)/(2)	**$ 0.005 ($/GJ)**
Customer	
(1) Customer Related O&M	$ 37,298 ($000)
(2) Total Customers	$ 704,317
(3) (1)/(2)	**$ 53 ($/customers)**

First, individual budgeted O&M items (BCUC accounts) were evaluated using BC Gas staff expertise to determine what portion of the activity varied either with the number of customers or with additional gas volumes. This variable portion was then assigned as demand, commodity or customer related using allocation factors derived from the FDC study.

The values expressed in $/GJ peak day, $/GJ, and $/customer were applied to the demand, commodity and customer components described in previous sections to arrive at total incremental cost estimates.[3]

[3] These O&M cost estimates are included in the summary table (Table 6) in Section 6.

Incremental O&M expenditures were also used to determine the overhead percentages to apply to transmission, distribution and customer related investments in the incremental demand and customer cost components. This was done by applying an allocation procedure, similar to that described above, on those O&M costs which are typically capitalized[4]. Table 5 below shows the derivation of demand (transmission and distribution) and customer (meters, services and mains) related overhead rates.

For demand related and customer related components, the portion of incremental O&M charged to capital was divided into the estimated total incremental direct capital expenditures for 1996. Incremental O&M costs were assumed to remain constant in real terms throughout the analysis period.

Table 5: Overhead Costs ($1996)	
Demand Related	
(1) O&M Charged to Capital	$ 2,201.250
(2) Total T&D Capital (1996)	$ 12,630,264
(3) Overhead Rate (1)/(2)	17%
New Customer Related	
(1) O&M Charged to Capital	$ 9,822,750
(2) Total Meters et. al. Capital (1996)	$ 26,600,830
(3) Overhead Rate (1)/(2)	37%

[4] O&M costs allocated to overhead were the variable portions of BCUC account items dealing with "Charges to capital".

6.0 SUMMARY

Economic theory holds that efficiency is best served when the price of a product or service reflects marginal costs. The purpose of this study is to establish estimates of the marginal cost of providing future gas service to consumers for the purposes of comparing rates with marginal cost. BC Gas has built on the LRIC study submitted in the Phase B Application and has modified the analysis to reflect the recommendations incorporated in the Commission's decision. While BC Gas is satisfied with the methodology it has employed in developing its marginal costs, caution needs to be used in applying the specific values for rate design purposes.

While both FDC and LRIC studies are to some extent subjective and judgemental, FDC studies are based on historic costs whereas incremental costs are based on long term forecasts of the future. Incremental costs are thus subject to considerable uncertainty. Some of these uncertainties include:

- forecasts of well-head gas prices
- forecast capital costs and requirements
- forecasts of gas demand
- Westcoast pipeline system toll forecasts
- the availability of future gas storage
- discount rates
- potential technological improvements

These factors influence the precision of the incremental cost estimates and should therefore be considered when applying the results to rate design.

The following is a summary of the demand, commodity and customer incremental cost estimates.

6.1 DEMAND COSTS

Table 6 below provides a summary of demand cost estimates for transmission, distribution, peak day demand and average demand.

Table 6: Demand Costs Summary ($1996)	
	($/GJ Peak Day)
Transmission*	$ 40
Distribution*	$ 47
Peak Day Demand (Supply)	$ 53
	($/GJ)
Avg. Demand Cost	$0.77

* Includes Operation and Maintenance Costs

The estimates for the value of peak day capacity, including operation and maintenance related costs, are $40/GJ peak day and $47/GJ peak day for transmission and distribution respectively. These estimates provide guidance for setting a price discount for interruptible capacity relative to firm capacity. At 100% load factor, these figures translate into a value of $0.24/GJ ($87/ 365 days / load factor) for transportation and distribution service.

The peak day supply cost of $53/GJ peak day represents the estimated cost of pure demand derived using the cost for a new LNG facility. The average demand cost of $0.77/GJ is an estimate of the incremental cost of average demand capacity for base load gas supply as derived using the Gas Supply Optimization Model (GSOM).

6.2 COMMODITY COSTS

Table 7 shows the levelized incremental commodity cost of gas. This estimate was derived using GSOM and includes related operation and maintenance costs.

Table 7: Commodity Costs Summary ($1996)	
	($/GJ)
Levelized Variable*	$ 0.95

* Includes Operation and Maintenance Costs

6.3 CUSTOMER CHARGES

Table 8 provides a summary incremental customer costs, indicative of the costs of attaching a typical new customer to the BC Gas system.

Table 8: Customer Costs Summary ($1996)		
Meters, Services & Mains	$/Customer	
	Per Year	Per Month
Rate 1	$ 251	$ 21
Rate 2	$ 269	$ 22
Rate 3	$ 628	$ 52

* Includes Operation and Maintenance

For residential, small commercial and large commercial customers, these costs do not vary over a wide range of gas consumption. To the extent that these customer costs reflect typical fixed costs, the estimates support higher basic charges for new customers in these markets.

FULLY DISTRIBUTED COST OF SERVICE STUDY

The fully distributed cost (FDC) study performed for purposes of this rate design application employs, except as noted herein, the same methodology as that of the FDC study in the 1993 Phase B Rate Design Hearing. The results of that study were accepted by the Commission in support of the revenue reallocation between customer classes (Decision dated October 25, 1993, Page 15).

As mentioned in BC Gas' evidence during that proceeding, the basic purpose of a FDC study is to compare the revenue generated by rates to the cost that a utility incurs in serving its customer classes. A FDC study is one element frequently considered in the setting of rates. It is worth emphasizing, however, that even though it is a useful guide in this regard, it is not a prescription for rate setting, as many other factors must also be taken into account.

In a manner similar to the general description of the FDC study in the 1993 Phase B Rate Design Application, the paragraphs below summarize the procedures employed.

1.0 FULLY DISTRIBUTED COSTING METHODOLOGY

There is no cost apportionment formula that is perfect from a theoretical standpoint and, at the same time, practical from an administrative point of view. The National Association of Regulatory Utility Commissioners, in its <u>Cost Allocation Manual</u>, and American Gas Association, in its <u>Gas Rate Fundamentals</u>, do not specify one method to the exclusion of all others. There are arguments that can be made for variants of fully distributed cost, i.e. coincident peak (CP), non-coincident peak (NCP), average and excess (A&E) and others.

As in the 1993 Phase B Rate Design Application, the approach taken by BC Gas in this application is to set out the findings under various methods of cost allocation as a basis for support for the rate design changes proposed. In this way, a range of costs is developed to illustrate the probable floor and ceiling for the cost of service.

2. CATEGORIES OF COST

Approximately 50% of BC Gas' cost of doing business relates to the cost of natural gas supplies. The remaining 50% of the cost that BC Gas incurs in serving its customers is for what can be called "cost of service margin" or "margin". It is the total cost to serve less cost of gas. The allocation of the total margin to customer classes is the topic of the material under this Tab.

There are three primary categories of cost causation factors in utility operations: demand-related cost, customer-related cost, and commodity-related cost. The first two are called "standing costs" -- the costs incurred in standing by to serve customers whenever they apply a load to the system. Commodity-related costs vary with consumption of energy and are called "running cost" or the additional cost that is incurred with the consumption of one more or one less gigajoule of gas. There are also revenue sensitive costs, e.g. one percent of revenue in lieu of property taxes on distribution facilities.

3.0 PROCEDURES INVOLVED IN FDC STUDIES

BC Gas has followed the traditional three steps in preparing fully distributed cost of service studies: 1) functionalization, 2) classification of function costs into demand, commodity, and customer-related components, and 3) allocation of these costs to the various rate classes. Functionalization is the determination of costs by utility functional groups: gas supply, gas supply administration, transmission, distribution, marketing and customer accounting. Classification is the separation of the functional groups into demand, commodity and customer components by cost causation. Allocation is the process of apportioning each of the functionalized and classified cost groups to the various classes of customers. When possible, costs have been directly assigned to specific customer classes that caused the cost. The process starts with the utility's chart of accounts.

3.1 Chart of Accounts

BC Gas maintains its accounting records in accordance with the uniform system of accounts prescribed by the Commission. These plant and revenue requirement records are the basic accounting data source for the fully distributed cost study.

3.2 Functionalization

The functionalization procedure begins with plant and operating expense accounts. The investment associated with each facility is assigned to a function, e.g. gas supply, gas supply administration, transmission, distribution, marketing and customer accounting. After assigning plant costs functionally, related expenses usually follows the same functionalization logic.

From this analysis, ratios based on the proportion of gas plant assigned to each cost of service function are developed. These plant ratios can be used for the functionalization of most of the other cost items. This process requires the assistance of the Company's engineering and accounting personnel to match the plant investment and associated operating expenses to the proper cost function.

3.3 Classification

In the next step of the FDC, functional cost is divided into cost causation categories. The three principal categories are demand-related, commodity-related and customer-related costs.

3.3.1 Demand-Related

The term demand (or capacity) refers to utility service that must be available upon the customer's demand. Demand related costs pertain to the peak usage of utility service by the Company's customers.

Storage (LNG), pipeline and compressor costs are assigned to the demand classification and can be apportioned on the basis of the relative demands placed on the system by the various customer classes.

3.3.2 Commodity-Related

A commodity-related cost is the variable cost of gas. Few of the costs to operate the facilities of BC Gas are variable with respect to the volume of gas delivered to customers. Gas supply administration expenses are classified as commodity-related cost in these FDC studies as a means to apportion the expenses to all sales and T-service customers.

3.3.3 Customer-Related

At the distribution level, the closer a plant item is physically located to a customer, e.g. a meter and service line, the more that particular item can be related to the requirements of that customer. Customer-related costs are those associated with services, meters, regulators, marketing and customer accounting. They are directly assigned in certain cases or are allocated to the customers of a particular class of service based on customer weighting factors.

A number of different approaches have been used by utilities to classify distribution mains costs. Sometimes distribution mains are classified as demand-related, in other FDC studies a portion of the cost of mains is classified as customer-related[1]. The latter is the approach most commonly used and has been employed in this FDC study. The concept of classifying some portion of the mains as customer-related is based on the premise that there is some cost incurred to reach the customer irrespective of the customer's capacity requirement. At the distribution level, the capacity of facilities is closely related to the number of customers connected to those facilities. In the 1993 FDC study, distribution mains were classified as demand related costs. In this study, BC Gas has used the zero-intercept method[2] to classify a portion of mains as customer-related. This method follows the more commonly used practice in the utility industry. In the Lower Mainland service area, the customer

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[1] For a discussion on classifying a portion of distribution mains as customer-related see the following: Gas Rate Fundamentals, American Gas Association, 1987, pg. 136; Electric Utility Cost Allocation Manual, National Association of Regulatory Utility Commissioners, 1992, pg. 86-95; Gas Distribution Rate Design Manual, NARUC Staff Subcommittee on Gas, 1989, pg. 22-23; and Principles of Public Utility Rates, James C. Bonbright, Albert L. Danielsen and David R. Kamerschen, Public Utilities Reports, Inc., 1988, pg. 490-492.

[2] Economic Growth in the Future: The Growth Debate in National and Global Perspective, Edison Electric Institute, McGraw-Hill Book Company, pg. 391-393; and Electric Utility Cost Allocation Manual, National Association of Regulatory Utility Commissioners, 1992, pg. 92-95.

-related portion is 20.9%, in the Inland service area it is 24.5% and in the Columbia service area 27.5%.

3.4 Capacity Allocation

Allocation of the functionalized and classified costs among the various classes of customers is the third step of the FDC process. As mentioned earlier, there are various methods that are used in this process. Three of the more commonly used methods have been employed in this study. They are the coincident peak (CP), non-coincident peak (NCP) and the average and excess (A&E) methods. Each is discussed below.

Consistent with the 1993 FDC study, the demand allocators for the firm industrial captive and bypass customers in the Inland service area have been weighted by transmission distance in this study.

For purposes of the 1996 study, all load factors used in the capacity allocation process were reviewed. As a result, the load factor for Rate Schedule 5, previously estimated at 45%, has been increased to 65%. All other load factors are close to those used in the 1993 FDC study, and reflect those used for the 1996 gas cost flow-through.

3.4.1 Coincident Peak (CP)

The CP method is used in this study to allocate capacity costs according to the demand imposed on the system by the various classes of customers during the peak day. The correlation between very cold weather and the firm system peak loads imposed on the BC Gas system forms the basis of using the coincident peak method as a capacity cost allocator. BC Gas builds it system on the basis of having to deliver gas to firm customers under extreme cold weather conditions.

The coincident peak method assigns the capital required to provide service during the peak load requirements of its customers.

3.4.2 Non-coincident Peak (NCP)

Under the NCP method of allocating capacity cost, the maximum rates of consumption of all customers or classes are added together irrespective of the time of occurrence to find the aggregate "non-coincident demand". In the case of BC Gas, peak day loads for the core customers are forecasted to occur on the coldest winter day, which for the NCP method is the same as for the CP method.

Industrial loads usually have a heating component to some extent, but they are more process oriented. Their peak loads may occur at times other than the coldest day of the year. It may be necessary to build certain portions of the system large enough to carry their loads regardless of when the coincident peak occurs. The NCP capacity cost allocation method is of assistance under these circumstances since capacity costs are allocated to each class according to the ratio of the maximum rate of consumption that each class bears to the aggregate non-coincident demand of all of the classes.

3.4.3 Average & Excess (A&E)

The A&E method is a two part calculation that takes into account the average use of the system and the non-coincident demands that are placed on the system. The method recognizes the dual service a pipeline system provides - a peak capacity deliverability service and a continuous throughput service. The first part of the formula recognizes the average demand of the system capacity. The second part of the formula recognizes the excess of non-coincident demand over average