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David M. Masuhara
Vice President
Legal, Regulatory & Logistics
and Secretary

February 5, 2001

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, BC V6Z 2N3

Attention: Mr. R.J. Pellatt
Commission Secretary

Dear Sir:

RE: 2001 RATE DESIGN APPLICATION

Pursuant to Order G-75-00 BC Gas files herewith 15 copies of its 2001 Rate Design Application. This Application deals with the delivery aspects of our rates and not the price of natural gas commodity.

One copy of all materials will be filed with registered intervenors who participated in the BC Gas SCP Cost Allocation proceeding under Order G-75-00.

Please note this Application requests Commission endorsement of a process to include technical work shops, issue and discussion meetings with interested parties and an alternative process for settling issues between parties.

Yours very truly,

BCGAS UTILITY LTD.

Original signed by D.M. Masuhara

David M. Masuhara

cc: Intervenors G-75-00

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IN THE MATTER OF
The Utilities Commission Act RSBC 1996, Chapter 473

and

IN THE MATTER OF
an Application by BC Gas Utility Ltd. to implement certain rate design changes

To: British Columbia Utilities Commission
Sixth Floor, 900 Howe Street
Vancouver, British Columbia
V6Z 2N3

APPLICATION

BC Gas Utility Ltd. ("BC Gas") hereby applies for approval of the proposals set out in this Application and in the material to which this Application pertains. These matters include:

COMMERCIAL TARIFFS

1. An Order approving the proposed revisions to the commercial rate schedules as set out in Tab 6.

INDUSTRIAL TARIFFS

2. An Order approving proposed amendments to the industrial rate schedules as set out in Tab 7.

GENERAL TERMS AND CONDITIONS

3. An Order approving proposed revisions to the General Terms and Conditions as set out in Tab 8.

DEFFERAL ACCOUNTS

4. An Order approving recovery of BC Gas, Commission and Participant hearing costs and other costs the Commission deems appropriate related to the Application.

RATE DESIGN IMPLEMENTATION

5. BC Gas seeks to have the interim increases in rates pursuant to BCUC Order G-75-00 be made permanent effective January 1, 2001. BC Gas seeks to have the revisions to the General Terms and Conditions be effective on filing of the approved revisions, to have the Backstopping, Balancing and UOR charges addressed in Tab 7 to be effective November 1, 2001, and to have all other proposed revisions effective January 1, 2002.

PUBLIC PROCESS

6. The Company seeks approval to adopt a public process to facilitate an understanding of the proposals, to receive comments, and to develop a specific list of issues and concerns. BC Gas further requests the Commission to endorse a negotiated settlement process to resolve issues arising from this Application.

In support of this Application, BC Gas has filed material to demonstrate that the proposals contained herein are just and reasonable, and not unduly discriminatory, nor unduly preferential.

All of which is respectfully submitted.

Dated at Vancouver, British Columbia, this 2nd day of February 2001.

BC GAS UTILITY LTD.

Per:

Original signed by D.M. Masuhara
David M. Masuhara

All notices and communications with regard to this Application should be sent to

BC Gas Utility Ltd.
Attn: David M. Masuhara
1111 West Georgia Street
Vancouver, British Columbia
V6E 4M4

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Facsimile: (604) 443 – 6904

RATE DESIGN APPLICATION - EXECUTIVE SUMMARY

This Application is a “Rate Design” Application that deals with how the total cost associated with providing gas delivery service to customers (excluding gas commodity costs) is allocated amongst the various classes of BC Gas’ customers. Matters relating to the price of natural gas commodity are not within the scope of this Application. BC Gas’ last comprehensive rate design review was performed in 1996. Since that time the number of customers and throughput on BC Gas’ system has changed, as have the total costs of serving BC Gas’ customers. In addition, there have been market developments that should be considered in a review of BC Gas’ rates and rate structures.

With regard to the total cost of service, a significant change is the addition of a number of major capital projects to the infrastructure supporting the gas utility. The most notable among these is the Southern Crossing Pipeline (SCP) project; others include the IBIS financial management system, the Mercury billing system, and new buildings and facilities. The costs of these projects are recovered in rates through revenue requirement increases. From time to time, it is important to review whether the manner in which increases in revenue requirement are passed through to customers appropriately reflects the costs of serving those customers and the benefits they receive from the investments made on their behalf. This Rate Design Application addresses this issue.

In addition to changes in the total cost of providing service, market developments should be considered in a rate design review. The introduction of commodity unbundling in British Columbia will affect the appropriate design of rates. Commodity unbundling is the regulatory process that once completed will offer all customers including residential and commercial customers, the opportunity to choose from whom they purchase the natural gas commodity they consume. In an unbundled market gas delivery service would continue to be provided by BC Gas. Commodity unbundling is contemplated to be in place as early as November 2002. This is an important consideration to the rate design process because as more and more customers elect to choose to acquire their gas supply from parties other than BC Gas, BC Gas' current role as the primary customer contact on natural gas issues will diminish. Therefore, BC Gas' ability to predict, influence and manage gas throughput will be reduced. In this market environment, gas delivery rates that are disproportionately weighted towards throughput while costs are essentially fixed may expose the Company to increasing risk.

The most significant market development since the Company's last rate design review is the volatile and high gas commodity market prices that have faced customers. Residential and Commercial delivered gas costs have increased dramatically since 1999. This sudden increase in gas prices has and may continue to further erode natural gas' price competitiveness relative to alternative fuels in all market segments. In response to the high unregulated commodity gas prices, some customers have switched to other options such as coal, fuel oil or electricity generated on peak periods by burning natural gas.

BC Gas is concerned that under the existing residential and commercial rate structure, customers will increasingly be substituting electric space heating for gas space heating. However, the source of incremental electric generation in B.C. and the U.S. West Coast will be gas-fired generation. Without appropriate changes to the energy policy in the province there may be significant erosion to both natural gas customer additions and existing customer base which will place an unsustainable burden on the electric system and unnecessarily add to greenhouse gas emissions.

Current gas prices highlight the importance of ensuring that the structure of rates within each rate class (the relative level of monthly and variable charges) is established appropriately. In the past, the relatively low commodity price of gas compared to electricity allowed gas utilities to recover most of their fixed costs in the variable delivery component of their rates because the delivered price of gas was well below the price for electricity. Today, the residential price for gas is very close to the rate for electricity. In this context, it is important to review whether historic rate structures continue to be appropriate going forward to ensure that natural gas and electricity rate structures promote optimal and sustainable responses by consumers.

The arguments made above suggest that from a purely technical perspective there may be a need to make changes to the level and structure of BC Gas' rates. However, as a pragmatic matter the customer impact of recent significant increases in gas commodity costs must also be considered. The impact of increased gas costs has been most pronounced for those commercial and industrial customers with energy costs that represent a significant portion of their operating and production costs and for residential customers on low or fixed incomes. BC Gas is sensitive to the financial impact that these increases have had on customers. Given this context, it is BC Gas' view that there must be compelling reasons for any rate increases resulting from the current rate design review.

BC Gas has identified a number of issues with regard to the structures of its rates and has made a number of specific rate design proposals supported by various studies. These studies include: revenue and customer bill impact models that illustrate the impact of proposed rates on customers' bills and utility revenues; cost of service studies which establish the relative cost of serving the various rate classes; and a survey of rates charged in other jurisdictions in Canada and the U.S.

Each of these studies has been used as a tool, having regard to the other considerations noted above, to assist in the determination of the appropriate level and structure of BC Gas' rates.

RATE DESIGN PROPOSALS

This Rate Design Application addresses 3 elements: 1) the relative level of rates between rate classes – also referred to as revenue realignment; 2) the structure of the rates within any given rate class; and 3) changes to general terms and conditions, tariffs or other contractual items. These three elements are discussed below.

REVENUE REALIGNMENT

BC Gas prepared Cost of Service studies to evaluate the relative cost of service for each of the firm service rate classes. This analysis includes all of the costs of owning, operating and maintaining the gas delivery infrastructure. The cost of service study prepared by BC Gas indicates that the rates as currently established reasonably recover the cost of service for each rate class. Based on the results of these studies, BC Gas concludes that revenue realignment is not needed at this time.

BC Gas also reviewed regional cost of service information to determine if a departure from the current postage stamp approach to delivery margin pricing was required. The analysis indicates that any regional differences with regard to gas delivery costs are not sufficiently material to warrant the implementation of regionally differential rates.

RATE STRUCTURES

Although the analyses do not indicate the need for revenue realignment between rate classes, the analyses do support making limited changes to some of the rate structures within the various rate classes. These proposals are outlined below.

RESIDENTIAL RATE PROPOSALS

Residential service (Rate Schedule 1) rates include a fixed monthly “basic charge” and variable gas cost recovery and delivery charges that vary with the amount of gas consumed. While most of the costs of serving customers are fixed (e.g. the service line, meter set and pipeline infrastructure), most of the costs are recovered in the variable delivery portion of rates.

The analysis prepared by BC Gas indicates that for residential customers, it would be appropriate to move towards establishing lower delivery and higher basic charges more consistent with the delivery and customer-related costs. If implemented, the lower delivery charges would offset the increased basic charge revenue, ensuring revenue neutrality for the class. These changes would improve the competitiveness of gas relative to alternate fuels, eliminate cross-subsidisation between lower volume users and other customers, and establish more efficient pricing signals so that optimal energy infrastructure investments are made in the province.

BC Gas performed an analysis, which considered a revenue neutral rate structure that would significantly increase the fixed basic charges to customers with only truly variable costs to be recovered in the “delivery charge” component of rates. This would improve the competitiveness of natural gas “on the margin” relative to regulated electricity prices.

However, the bill impact analysis indicates that the impact of implementing these changes would be significant for lower volume customers particularly in view of the current gas commodity prices. In addition, without greater transparency of the various components of the residential customer bill, the perceived customer impact of increasing the basic charges and reducing delivery charges would be greater since the bill would not clearly show the offsetting reduction in the delivery charges. Accordingly, BC Gas proposes that changes to the residential rate structures be made at a future date with the development of new bill formats and unbundling and in the context of a comprehensive Provincial energy strategy.

COMMERCIAL RATE PROPOSALS

There are two commercial service classes: Small Commercial service (Rate 2) and Large Commercial Service (Sales - Rate 3 and Transportation - Rate 23). Small commercial service applies to commercial, institutional or light industrial applications of less than 2,000 GJ per year. Large Commercial service is restricted to customers using more than 2,000 GJ’s per year.

Similar to the rate structure for residential service, commercial rates include a fixed monthly basic charge and variable gas cost recovery and delivery charges that vary with the amount of gas consumed. Most of the costs of serving commercial customers are fixed (e.g. the service line, meter set and pipeline infrastructure), but most of the costs are recovered in the variable delivery portion of rates. Similar to the residential customer rates, the mismatch between the fixed and variable cost of service and the rate structures indicates a need for higher basic charges and lower delivery charges. These changes would also enhance natural gas’ competitiveness relative to other energy sources. A further factor that argues in favour of changes to the commercial rate structure is that under the current rate structure there is a disconnect between the minimum volume requirement and the relative economics of Rate Schedule 2 and 3/23. Currently, a customer's rates would be lower on Rate 3/23 at volume levels that are well below the minimum 2,000 GJ annual threshold.

The changes required to establish an economic break point at 2,000 GJ and to align rates with costs would result in unacceptable impacts on customers, particularly in view of the current gas price environment. Accordingly, BC Gas proposes that the Rate Schedule 2 basic and delivery charges be set out at $21.00/month and $2.095/GJ respectively. BC Gas also proposes that Rate Schedule 3/23 basic and delivery charges be set out $112.00/month and $1.806/GJ.

The proposed basic charges and delivery charges establish an economic crossover point between Small and Large Commercial service more reflective of the 2,000 Gigajoule per year break point and move the monthly basic charges more in line with fixed customer and demand related costs associated with serving these respective customer classes.

GENERAL FIRM RATE PROPOSALS

Rate Schedule 5/25 – General Firm Service is generally used by larger volume process load customers who use gas for more than space heating. Rate Schedule 5 is the General Firm Sales rate and Rate Schedule 25 is the comparable transportation service option where customers purchase their commodity from gas marketers. Rate Schedule 5/25 includes monthly basic and variable delivery charge components similar to those included in the residential and commercial rate classes and also includes a monthly demand charge. BC Gas is not proposing any changes to this Rate Schedule.

INTERRUPTIBLE RATE PROPOSALS

Interruptible service schedules provide customers that are able to have their service curtailed or interrupted during peak periods with non-firm service at discounted rates. These schedules allow interruptible customers to utilise capacity that is excess to firm service customers requirements thereby reducing the net cost of service that must be recovered in firm service rates. BC Gas has two interruptible service schedules: Rate Schedule 7/27 – General Interruptible Service and Rate Schedule 22 – Large Volume Transportation Service.

Both of these rate schedules include basic and delivery charges (and the Transportation Service Administration Charge for transportation service customers). They are priced at discounts from firm service, where the discount reflects the amount deemed to be sufficient to encourage interruptible customers to remain interruptible (thereby avoiding the need for firm system infrastructure reinforcement) while maximising the amount of revenue credited back to firm service customers. BC Gas is not proposing any changes to the level or structure of the interruptible rates in this Application.

LARGE INDUSTRIAL RATE PROPOSALS

Rate Schedule 22A is a closed transportation service schedule available to certain customers in the Inland service area. The customers eligible for service under this rate schedule are listed in the Rate Schedule 22A transportation tariff. Rate Schedule 22B is a closed transportation service schedule available to certain customers in the Columbia service area. The customers eligible for service under Rate Schedule 22B are set out in the Rate Schedule 22B tariff. BC Gas is not proposing changes to either of these rate schedules in this Application.

TARIFF ADMINISTRATION AND GENERAL TERMS AND CONDITIONS

BC Gas proposes to make changes to the rates for Backstopping, Balancing and Unauthorized Overrun charges. In particular, BC Gas proposes that the charges be adjusted effective November 1, 2001.

The General Terms and Conditions are the BCUC approved terms and conditions governing the provision of utility service by BC Gas. Together with the rate schedules they form the BC Gas Tariff. BC Gas is not proposing to modify any of the rate schedules or service agreements. Revisions to the General Terms and Conditions are proposed. BC Gas proposes that these revisions be effective upon approval and filing of the revised General Terms and Conditions.

A re-write of various transportation schedules is planned for later this year and will be filed as part of a separate process. The intention is to simplify the contracts and address a number of terms and conditions that do not relate to the rate structure.

PUBLIC PROCESS

In this Application the Company has put forward proposals which, in its view, are in the interest of its customers. BC Gas has met with a number of customers groups and their representatives prior to filing this Application. Support for exploring alternative approaches to addressing rate design issues outside of the formal hearing process were expressed during these meetings.

BC Gas requests that the Commission give consideration to a workshop prior to the hearing, at which time issues and concerns can be reviewed and at which the best means of resolving those issues or concerns can be discussed. BC Gas also requests Commission endorsement of a negotiated settlement to resolve issues arising from this application.

CONCLUSION

The rate design proposals in this application are the result of the consideration and underlying analyses of numerous factors. These include detailed cost studies, tariff reviews and previous Commission decisions and directives. The proposals included in this Application respond to the market circumstances facing BC Gas and its customers. Where changes are warranted but have not been proposed, this Application also highlights the need to continue to ensure that regulated energy pricing supports an optimal allocation of the Province’s resources. The proposals herein reflect a reasonable balance among those numerous factors relied upon in establishing just and reasonable rates and, therefore, should be adopted by the Commission. However, BC Gas encourages the Commission and other key Stakeholder groups to collectively work to find acceptable ways to improve the unsustainable manner in which gas and electricity commodity prices are determined in B.C.

INTRODUCTION & BACKGROUND

1.0 DESCRIPTION OF BC GAS UTILITY LTD.

BC Gas Utility Ltd. ("BC Gas" or "the Company") is the largest distributor of natural gas in British Columbia, with approximately 760,000 residential, commercial and industrial customers. BC Gas is regulated by the British Columbia Utilities Commission (“BCUC” or “Commission”). BC Gas owns and operates distribution and transmission facilities used for the delivery of natural gas to its customers. The costs of owning, operating and maintaining these facilities is recovered in the delivery portion of rates (referred to as “delivery margin”). This Application is a “Rate Design” Application and does not deal with the level of these costs but deals with how the delivery margin is divided among the various classes of BC Gas’ customers.

BC Gas purchases natural gas from producers and marketers of natural gas on behalf of its residential, commercial and industrial sales customers. BC Gas is not involved in exploration for, or production of, natural gas and is not affiliated with any company in that business. The gas purchased by BC Gas is re-sold to customers. The cost of the gas purchased by BC Gas is passed on to customers without a “mark-up” or profit to BC Gas and is recovered in rates through a gas cost recovery charge. This Application does not deal with the cost of gas purchased by BC Gas and re-sold to customers.

2.0 BC GAS RATE DESIGN HISTORY

BC Gas filed its first rate design application for the amalgamated BC Gas company (excluding Fort Nelson which was addressed separately) in April 1993. The 1993 Rate Design Application dealt with the allocation of costs, other than gas supply costs, between rate classes. The Commission approved much of the application in its Decision of October 1993. The 1993 Rate Design Application also addressed a number of rate design issues that resulted in the establishment of a revised and common set of rates and General Terms and Conditions to be applied across the BC Gas service area (other than Fort Nelson). The Commission supported the proposal of BC Gas to price interruptible service at a discount from firm service based on the value of service. The revised industrial rates came into effect on November 1, 1993 and the new residential and commercial rates came into effect on January 1, 1994.

The most recent comprehensive rate design review was undertaken through the Company’s 1996 Rate Design Application. The primary elements of the 1996 Application included improved revenue alignment among classes to better reflect the class cost of service. BC Gas also sought to rationalise and simplify its industrial rate schedules and service agreements and to clarify several of the Company’s General Terms and Conditions. The Application also highlighted the need to move residential and commercial monthly basic charges closer to the fixed costs of service.

A Negotiated Settlement Process (“NSP”) was undertaken in the 1996 proceedings. Virtually all of the issues addressed in the Company’s Application were resolved through the NSP, which was approved by the Commission in October 1996.

BC Gas initiated an Integrated Resource Planning process in 1997 which identified the Southern Crossing Pipeline ("SCP") as the least cost option to satisfy demand growth requirements. After a detailed review process, the SCP was approved by the BCUC in May 1999. The appropriate rate treatment of the SCP cost of service was raised during the SCP review process due to the relative size of this project and the variety of benefits it would provide. BC Gas filed its SCP Cost Allocation Application in March 2000. In order to ensure that a rate design determination was made prior to the in-service date of SCP (November 2000), the SCP Cost Allocation Application was limited to the issues of SCP cost recovery and tariff amendments to provide transportation service customers with increased flexibility and access to SCP capacity.

A NSP was undertaken in respect of the SCP Cost Allocation Application which successfully resolved the issues and interim rates were established effective January 1, 2001 for the recovery of the SCP cost of service. The BCUC Decision approving the NSP directed BC Gas to file a comprehensive rate design application to address the broader issues not included in the SCP Cost Allocation process. This Application responds to that direction and puts forward a number of proposals related to the appropriate level and structure of BC Gas' rate schedules.

3.0 APPLICATION SCOPE & PURPOSE

The Rate Design process is one of the processes used to establish the prices or rates charged by regulated utilities for the services they provide. All rates charged by BC Gas for tariffed service are approved by the BCUC. Rate Design reviews are undertaken periodically – typically every 3 to 5 years – to determine whether the Company's total costs are being recovered equitably among, and within, the classes of the Company's customers and to determine that the rates are just and reasonable. This Application recognizes changes that have transpired since 1996 including changes in the mix and number of customers and their respective throughput and demand as well as system infrastructure investments made to serve BC Gas' customers.

A significant change to the Company's cost structure since 1996 is the addition of a number of major capital projects to the infrastructure supporting the gas utility. The most notable among these is the Southern Crossing Pipeline project; others include the IBIS financial management system, the Mercury billing system, and new buildings and facilities. The costs of these projects are recovered in rates through revenue requirement increases approved by the BCUC. From time to time, it is important to review whether the manner in which increases in revenue requirement are passed through to customers appropriately reflects the costs of serving those customers and the benefits they receive from the investments made on their behalf. This Rate Design Application addresses this issue.

In addition to growth in demand and associated costs, there have been a number of significant market developments that must be considered in a review of BC Gas' rates and rate structures.

4.0 RECENT GAS MARKET DEVELOPMENTS

A significant market development is the proposed introduction of commodity unbundling in British Columbia. Commodity unbundling is the regulatory process that once completed will offer all customers the opportunity to choose from whom they purchase the natural gas commodity that they consume. Currently only large commercial and industrial customers have viable direct gas commodity purchase options. In an unbundled market, gas delivery service would continue to be provided by BC Gas but residential and commercial customers would now be able to negotiate the purchase of their gas commodity requirements directly from a wide variety of gas marketers. BC Gas has had a number of meetings with stakeholders, customer representatives, and marketers to establish a process for introducing enhanced customer choice to smaller volume customers. In the fall of 2000 all parties resolved to proceed with unbundling with a view to having residential and commercial commodity unbundling in place as early as November 2002.

A process separate from this Application is underway to establish the regulatory and market rules for the unbundled market including: consumer protection, billing and gas supply management rules. Commodity unbundling is an important consideration to the rate design process because the gas commodity represents more then two-thirds of the customer's total bill. As more and more customers elect to choose to acquire their gas supply from parties other than BC Gas, BC Gas' current role as the primary customer contact on natural gas issues will diminish and its ability to predict and influence matters that affect gas throughput will be reduced. In such a market environment, gas delivery rates that are disproportionately weighted towards throughput while costs are essentially fixed expose the Company to increasing risk. In other jurisdictions, as utilities move towards unbundling there has been a trend towards recovering a greater percentage of fixed costs through fixed charges rather than throughput based delivery charges.

Commodity unbundling will also require gas costs to be identified on customers' bills. Customers' bills currently display the fixed monthly charges as a separate item; however, the delivery charges and gas commodity portions of the rates have not been separated. This makes rate design changes less transparent to customers. Even though reductions in delivery charges may offset increased basic charges, this may not be apparent to many customers who view the variable portion of the bill as being entirely commodity costs. Concurrent with the move towards unbundling, BC Gas will be breaking out the three separate components of customers' bills – basic monthly charge, delivery charge and gas cost recovery charge. This will facilitate the move towards customer commodity choice and enhance understanding of the fixed and variable delivery charges so that future rate design changes can be made to better align rates with costs.

High gas prices highlight the importance of ensuring that the structure of rates within each rate class (the relative level of basic and variable charges) is established appropriately. In the past, the relatively low commodity price of gas compared to electricity allowed gas utilities to recover most of their fixed costs in the variable delivery component of their rates because the delivered cost of gas was still well below the rate for electricity. Today, the residential delivered price of gas is very close to the residential rate for electricity. Gas prices are expected to increase or remain at high levels in the near term before new supplies and supply infrastructure are developed and brought on line. While gas prices should soften over the medium to long term, it is unlikely that natural gas prices will return to the levels experienced in the past. In this context, it is important to review whether historic rate structures continue to be appropriate to ensure that differences in natural gas and electricity rate structures promote optimal and sustainable allocations of scarce resources.

BC Gas is concerned that given thecombination of deregulated natural gas commodity prices competing against low hydro generated electric prices, customers will increasingly be substituting electric space heating for gas heating. However, this electricity will be generated, particularly on winter peak day periods, through gas-fired generation. Current minimum gas furnace efficiencies are 78% and new residential and commercial gas furnaces are up to 95% efficient whereas new electric generating plants operate at less than 60% efficiency and older gas-fired generating plants are even less efficient. Consequently, using electricity from a gas fired generating plant for space heating will result in 40-50% more gas use and consequently emit 40-50% more greenhouse gases than the direct use of gas for space heating. Furthermore, more gas use will result in higher gas prices that will lead to more electricity consumption. Regulated energy pricing should not encourage such inefficiencies. Without appropriate changes to the rate structures, BC Gas is concerned that there could be significant erosion to both its customer additions and existing customer base which will place an unsustainable burden on the electric system and unnecessarily add to greenhouse gas emissions.

Since the last BC Gas rate design review, customers have been exposed to volatile and markedly higher gas commodity market prices than had previously been experienced. This sudden increase in gas prices has eroded natural gas' price competitiveness relative to alternative fuels in all market segments. In response to the high gas prices, some of BC Gas' customers have switched to other options such as electricity, fuel oil and coal. Residential and commercial delivered prices have increased dramatically since 1999. The impact of higher gas price have been most pronounced for those industrial customers for whom energy costs represent a significant portion of their operating and production costs and for residential customers on low or fixed incomes. BC Gas is sensitive to the financial impact that these increases have had on customers. Within this context, it is BC Gas' view that there must be compelling reasons for rate increases for any of these rate classes as a result of this current rate design review.

5.0 RATE DESIGN OBJECTIVES

For this Rate Design Application BC Gas has undertaken a review of the appropriate level and structure of each class of the Company's rates. In developing the rate proposals in this Application, BC Gas had regard to accepted rate design principles, including those outlined below.

1. Economic Efficiency - The rate design should better align the rates with the costs of serving each class. The proposals should recognise the rate classes that use the system more efficiently.

2. Fairness - Under the proposed rates similar customers should pay similar delivery margins for utility services and the rate proposals should better align rates with the "user-pay" philosophy.

3. Stability - Rate proposals should achieve greater stability in the recovery of delivery margin and to the extent possible stabilize customers’ bills.

4. Customer Impact – Bill impact analyses should ensure that the rate design changes do not unduly impact customers’ bills.

5. Ease of Understandability, Administration and Rate Continuity - Rates should be understood by customers and easily administered by the Company. Changes should be gradually implemented where possible, ensuring consistency and continuity in application.

6. Recovering the Revenue Requirement - The proposed rates should provide sufficient revenues to recover the Company’s costs of providing service.

7. Competitiveness – The rate proposals need to take into account the relative price competitiveness of gas to other alternatives.

6.0 BC GAS TARIFF OVERVIEW

The General Terms and Conditions are the BCUC approved terms and conditions governing the provision of utility service by BC Gas. Together with the rate schedules they form the BC Gas Tariff. This Application addresses all the rate schedules included in the BC Gas Tariff and introduces minor amendments to the General Terms and Conditions. In addition to the standard rate schedules, BC Gas has a number of Tariff Supplements and By-Pass Agreements in place. These agreements have been negotiated and approved separately by the BCUC and do not form part of this Application.

The following is a list and description of the rate schedules offered by BC Gas:

Residential Service (Rate 1) - includes service to single family residences, separately metered single family townhomes, rowhouses and apartments. Most residential customers use natural gas for space and water heating, fireplaces and to a lesser extent cooking and clothes drying. Usage varies depending on the types of appliances installed but typically ranges from about 60 GJ to 180 GJ per year per household. Residential rates include a fixed monthly “basic charge” and gas cost recovery and delivery charges that vary with the amount of gas consumed. While most of the costs of serving customers are fixed (e.g. the service line, meter set and pipeline infrastructure), most of the costs are recovered in the variable delivery portion of rates.

Small Commercial Service (Rate 2) - Small commercial service applies to commercial, institutional or light industrial applications of less than 2,000 GJ per year which generally includes service to small businesses, small apartment buildings and restaurants. Similar to the rate structure for residential service, commercial rates include a fixed monthly basic charge and gas cost recovery and delivery charges that vary with the amount of gas consumed.

Large Commercial Service (Rate Schedule 3/23) - Large Commercial service is restricted to customers using more than 2,000 GJ per year. Customers served on this rate schedule include larger commercial, institutional and small industrial operations. Annual usage can vary from 2,000 to 10,000 GJ per year. Rate Schedule 23 is the transportation option for Rate Schedule 3 customers that provides the opportunity for customers to purchase their gas supply requirements from a party other than BC Gas.

Large Commercial rates feature a higher monthly basic charge and lower variable gas cost recovery and delivery charges than the Small Commercial rates. As Rate Schedule 23 customers purchase their gas directly from a marketer rather than BC gas, their rates do not include a gas cost recovery charge. However, all transportation service customers pay a transportation service administration fee to recover the incremental costs of administering transportation service.

As in the case of residential service, most of the costs of serving commercial customers are fixed (e.g. the service line, meter set and pipeline infrastructure), but most of the costs are recovered in the variable delivery portion of rates.

Seasonal Service (Rate 4) – Seasonal Service is available to customers such as paving companies and municipal swimming pools that consume natural gas mainly during the summer season (April to October). The average usage for this rate class ranges from as low as 2,500 GJ to as much as 14,000 GJ per year. There are a relatively small number of customers served under this rate schedule (less than 50 customers). The service is firm (not interruptible due to system or gas supply constraints) during the summer period but service may be available at other times of the year on an interruptible basis. Rate 4 includes a monthly basic charge payable during any month in which there is consumption and a variable delivery and gas cost recovery charge.

<u>General Firm Service (Rate Schedule 5/25)</u> – This rate schedule is generally used by larger volume process load customers who use gas for more than space heating. Rate Schedule 5 is the General Firm Sales rate and Rate Schedule 25 is the comparable transportation service option under which customers purchase their commodity from gas marketeters. Due to the non-space heating usage under Rate Schedule 5/25, customers in this rate class usually have a higher load factor than residential and commercial customers (i.e. the ratio of average to peak usage is greater). Rate Schedule 5/25 includes a monthly basic charge and variable delivery charge components similar to those included in the residential and commercial rate classes but also includes a monthly demand charge. The monthly demand charge recovers some of the fixed demand related costs of serving this class of customers. Customers pay a demand charge reflecting the demand they place on the system infrastructure required to meet their peak usage. The better the customer’s individual load factor, the lower the demand charge per unit of consumption.

<u>Natural Gas Vehicle Service (Rate Schedule 6)</u> – Natural Gas Vehicle Service is available to customers who retail natural gas to customers with natural gas vehicles or fleet customers who use natural gas for their own fleet. Typical end-use applications include light, medium and heavy-duty vehicles and ferries. The average usage for this rate class ranges from 16,000 GJ in the Lower Mainland to 7,000 GJ per year in the Inland Service Area. Rate Schedule 6 includes a monthly basic charge and a variable delivery and gas cost recovery charge.

General Interruptible Service (Rate Schedule 7/27) – The General Interruptible Service schedule provides customers that are able to have their service curtailed or interrupted during peak periods with non-firm service at discounted rates. This schedule allows interruptible customers to utilise capacity that is excess to firm service customers requirements during most of the year thereby reducing the net cost of service that must be recovered in firm service rates. Rate Schedule 27 is the direct purchase option for Rate Schedule 7 customers that allows General Interruptible customers to purchase their gas supply requirements from a marketer. Customers served on Rate Schedules 7 and 27 typically include larger volume process load customers such as manufacturing, greenhouse and service industries that can tolerate interruption or curtailment of their gas use. Annual gas use can range from 10,000 GJ per year to as much as 150,000 GJ per year.

Rate Schedules 7/27 have the same basic charges and delivery charges; the only difference being reflected in the absence of a gas cost recovery charge and the addition of the Transportation Service Administration Charge for Rate Schedule 27 transportation service customers. General Interruptible service is priced at a discount from the General Firm Service rate, where the discount reflects the amount deemed to be sufficient to encourage interruptible customers to remain interruptible (thereby avoiding the need for firm system infrastructure reinforcement) while maximising the amount of revenue credited back to firm service customers.

Large Volume Transportation (Rate Schedule 22) - BC Gas' largest interruptible customers will typically be served under Rate Schedule 22 – Large Volume Transportation service. Rate Schedule 22 customers include industrial and institutional applications that may be curtailed at any time if BC Gas does not have adequate capacity on its system to accommodate its customers' requirements. In order to qualify for service under this rate, customers must satisfy a minimum usage requirement of 12,000 GJ per month. In months where the minimum usage has not been met, the customer must pay the rates associated with the 12,000 GJ minimum volume requirement. This provision is part of the differentiation of Rate Schedule 22 from Rate Schedule 27 and is part of the reason Rate Schedule 22 has a larger discount then Rate Schedule 27. Annual usage can range from 150,000 GJ per year to 2,000,000 GJ per year. As is the case for the General Interruptible Service - Rate Schedule 7/27, Large Volume Interruptible Transportation Service – Rate Schedule 22 is priced at a discount from firm service.

Closed Transportation Schedules (Rate Schedule 22A/22B) – Closed rate schedules are not available to customers other than those that were being served on those rate schedules when the rate schedules were closed. Customers served on the closed rate schedules have the option to be served under the other standard Rate Schedules but typically prefer the rates or terms and conditions offered under the closed rate schedule. Rate Schedule 22A is a closed transportation service schedule available to certain large volume customers in the Inland Service Area. The customers eligible for service under this rate schedule are listed in the Rate Schedule 22A transportation tariff. Rate Schedule 22B is a closed transportation service schedule available to certain large volume customers in the Columbia Service Area. The customers eligible for service under Rate Schedule 22B are set out in the Rate Schedule 22B tariff.

7.0 STUDIES

In considering the appropriate rate design for BC Gas, the following studies were undertaken to assist in determining an appropriate rate level and structure for customer classes.

1. Detailed revenue and customer bill impact models that illustrate the impact of proposed rates on customer's bills and utility revenues. Summary tables are provided under Tab 6 for Commercial customers. Customer impact tables are not included for Residential or Industrial customers as no rate changes are proposed.

2. Cost of Service studies have been completed. Cost of Service studies are used to estimate the relative cost of serving the various rate classes and to establish the customer, demand and delivery related costs of serving customer within each rate class. For this Application, Cost of Service studies were conducted using a methodology consistent with that used in 1996, employing a coincident peak methodology. A discussion of the methodology and the results of the Cost of Service studies can be found in Tab 4, with additional detail provided under Tab 9.

3. A survey of residential and commercial gas rates charged in other jurisdictions in Canada and the U.S. was undertaken and is filed in Tab 10. These rate comparisons are useful for comparing the proposed rates to those charged in other regulatory jurisdictions. Rate comparisons are not provided for industrial services because of the difficulty associated with reflecting tariff differences that may have significant impacts on the relative economics of service across the various jurisdictions.

Each of these studies have been used as a tool, having regard to the other considerations noted above, to assist in the determination of the appropriate level and structure of the rate classes of BC Gas.

BC Gas worked closely with Navigant Consulting Inc., a consulting firm with expertise in Cost of Service Study analysis and rate design, in developing the above studies and the rate proposals they support. Navigant assisted BC Gas in preparing the SCP Cost Allocation Application and in the related Negotiated Settlement Process.

CLASS REVENUE & COST COMPARISONS

1.0 BACKGROUND

The rate design objectives of encouraging economic efficiency, fairness, and competitiveness, generally require that prices reflect the cost of providing service. A Cost of Service Study is one of the primary tools used to establish cost guidelines for the evaluation of rate class revenue levels and rate structures. This evaluation process includes a comparison of the delivery margin levels and revenue (delivery margin plus cost of gas recovery) level for each class of customers, with the costs of serving the respective classes. These comparisons, referred to as margin to cost ratios and revenue to cost ratios, show whether the rates charged to a certain rate classes recover the indicated cost of service of that class. By adjusting rates, the margin and revenue recovered from a class of customers can be brought closer to the indicated cost of service for that class, resulting in a ratio of revenue or margin to cost that approaches 100%. When evaluating the acceptability of the resulting ratios, a reasonable balance between the criteria that relate to the design of utility rates must be considered. The following criteria were considered: 1) cost of service results; 2) class contribution to present revenue levels; 3) customer impacts; and 4) the prevailing natural gas market environment.

Revenue and margin to cost ratios have been calculated for all firm service customers. Capacity related costs have been allocated using the coincident system peak demand method which means that the cost of service analyses do not allocate any transmission or distribution capacity costs to interruptible customers because these customers are assumed to be interrupted during peak periods. While there are customer site specific plant investments and operating costs associated with providing interruptible service, such as meter reading and billing, BC Gas does not include interruptible loads when planning or designing the capacity of its system. Interruptible customers are assumed to be utilizing capacity excess to firm customers’ requirements. Therefore, revenue and margin to cost ratios are not meaningful for establishing rates for interruptible service. Rather than using cost of service results for pricing interruptible service, interruptible service rates are based on a discount from comparable firm service rates. BC Gas’ approach to interruptible pricing is more fully discussed under Tab 7.

Prior to commodity unbundling for larger volume customers, revenue to cost ratios were deemed to be acceptable if they fell within a range of 90% to 110%. This “zone of reasonableness” recognized the subjectivity inherent in any allocation of joint costs. With commodity unbundling, delivery margin to cost ratios have been more frequently used for rate setting purposes since gas commodity costs do not form part of the cost of service for transportation service customers. The 90% to 110% range has been maintained for the margin to cost ratio creating a narrower effective zone of reasonableness than was previously used.

In view of the recent significant increases in natural gas commodity prices and the sensitivity of all customers classes to further rate changes, BC Gas believes that a strict application of the 90 to 110% zone of reasonableness for margin to cost ratios would be inappropriate in today’s market environment. More specifically, BC Gas recommends that the zone needs to be broadened for this review.

2.0 COST OF SERVICE STUDY METHODOLOGY

This section provides an overview of the cost of service methodology and a summary of the results of the cost of service analyses used in support of the rate recommendations made in this

Application. A more detailed discussion of cost of service is provided in Tab 9 along with supporting schedules.

For historical context, this section first outlines key elements of the methodology supporting the 1996 Rate Design Application Settlement study and the margin and revenue to cost results of that Cost of Service analysis. This analysis and the results rely on the data available in 1996. The methodology and results of that study are described in Section 2.1 below. For ease of comparison, the 1996 Settlement analysis has also been updated to reflect current input data while holding the methodology unchanged. The key changes made to the input data are outlined in Section 2.2. The analysis that combines the 1996 methodology with updated input data is labeled “2001 Baseline” and is summarized in Section 2.3. Details of the 2001 Baseline case are included in Tab 9. Finally, BC Gas has modified the methodology supporting the 1996 Settlement and 2001 Baseline analyses to reflect a more appropriate allocation of distribution system costs. This analysis represents BC Gas’ application case and is labeled “2001 Application”. Details of the 2001 Application analysis are also included under Tab 9.

2.1 1996 SETTLEMENT METHODOLOGY

The most recent review of class revenues and cost was performed in support of the 1996 Rate Design Application. The parties to the settlement of the BC Gas 1996 Rate Design Application did not endorse any particular methodology for purposes of cost allocation. However, the underlying Cost of Service analysis that was relied upon for purposes of the settlement applied particular approaches to classifying and allocating costs. In its current review of the utility cost of service, BC Gas used the results of the Settlement of the 1996 Application and the underlying cost of service methodology as the baseline before updating the study for current data or revised methodologies. This approach facilitates a comparison of how revenue to cost ratios have changed over the last five years independent of other variables that can be introduced such as methodological changes. The results of the Settlement study are summarized in Table 4.1 below.

The 1996 Settlement study employed a coincident peak methodology and classified 100% of distribution mains' investment as demand related. Transmission costs were allocated to all customers based on their contribution to peak demand, except for the Inland Service Area customers in Rates Schedule 5/25 and Rate Schedule 22A. The demands of the Inland Service Area industrial customers were adjusted to reflect the average distance on the Inland Transmission System, referred to as a demand – distance method. This distance-weighting approach to adjusting peak demands of certain industrial customer classes originated in the 1987 Rate Design Application of Inland Natural Gas.

2.2 2001 INPUT DATA UPDATES

The 2001 Baseline and 2001 Application cost of service studies update the input variables used in 1996 to reflect current values. These changes in input data include updated numbers of customers, throughput, demand, and operating and maintenance and capital costs. These items are discussed in greater detail under Tab 9. The capital costs included in the updated study include, but are not limited to the Southern Crossing Pipeline (SCP).

The SCP is a new large diameter addition to BC Gas' transmission system, operating between Oliver and the interconnect of BC Gas' system with TransCanada's B.C. system at Yahk, B.C. SCP capacity allows BC Gas' customers to access diverse gas supplies associated with production from Alberta to meet growth in peaking and seasonal demand in the Lower Mainland

and the Interior. SCP was placed into service at the end of November 2000.

In the 2000 SCP Cost Allocation filing, the Company approached the principle of cost allocation from a position that customers who benefit from SCP should pay. The evaluation process examined the various benefits identified and quantified by the Commission through the Certificate of Public Convenience and Necessity (CPCN) approval process and assessed costs to each customer group based on the long term value received. These benefits included a) use of the new capacity to access diverse peaking supplies, b) lower future cost of pipeline reinforcement and rehabilitation in the Interior system, c) enhanced ability to provide balancing of planned and actual gas loads, d) better security of supply, and e) opportunities for incremental revenues from third parties.

The agreement reached during the NSP process balanced the issue of equitable access and assignment of benefits to each customer class. Included in the 2000 SCP Cost Allocation filing was an allocation of costs to the various customer classes based on benefits received. That allocation of costs indicated that, aside from Rate Schedule 22B customers, the results of the allocation of costs to customer classes based on identified benefits was similar to the allocation of costs that would result from treating SCP in the same manner as other transmission plant. Both of those approaches to the allocation of SCP costs indicated that it was appropriate to recover SCP costs based on an equal percentage increase in the contribution to delivery margin by customers.

A key element of the SCP Cost Allocation (Phase 1) proceeding was the recognition of the SCP benefits provided to both sales and transportation customers. It would not be fair for some groups of customers to receive the benefits of SCP and then avoid the associated costs by migrating to transportation service under the auspices of customer choice and the growth of unbundling. The least complicated method to ensure that costs were assigned fairly is to ensure that all costs remain in BC Gas' delivery service margin provided that transportation customers received a level of benefit that was comparable to that of sales customers.

Consistent with the cost allocation agreed to by parties to the SCP Cost Allocation Settlement, the SCP costs have been allocated to all non-bypass firm customers, except Rate Schedule 22B large industrial customers, on the basis of the contribution of each rate class to peak demand. Rate Schedule 22B customers have been exempted from the allocation of SCP costs reflecting the fact that their supply arrangements are upstream of the Yahk pipeline interconnection point with SCP and separate from BC Gas' supply portfolio. The allocation of SCP is described in more detail under Tab 9.

2.3 2001 BASELINE STUDY RESULTS

As discussed above, the 2001 Baseline Study maintains the same methodology as was used in the 1996 Settlement analysis but includes updated input data. In particular, the cost of service analysis includes a 100% demand related classification of distribution mains consistent with the methodology underlying the 1996 settlement. The results of the 2001 Baseline Cost of Service analysis appear in Tab 9, Section A, pages 1 - 4.

The resultant revenue to cost ratios are summarized in Table 4.1 below.

The table shows that almost all of the margin to cost ratios have improved (i.e. moved closer to 100%) for each rate class and remain within the 90 – 110% zone of reasonableness. When revenue to cost ratios are considered, the ratios are even more favorable for each of the company's sales classes.

This suggests that the manner in which increased revenue requirements have been flowed through to customers since 1996 has been representative of the costs of serving each of the various rate classes.

The Rate Schedule 5/25 margin to cost ratio has improved relative to the margin to cost ratio calculated in 1996, moving from 137.5% to 113%. Similarly, the residential and small commercial margin to cost ratios also have moved towards 100% from the levels estimated in 1996.

2.4 2001 APPLICATION STUDY RESULTS

The margin and revenue to cost ratios for each customer class in the 2001 Application Cost of Service analysis study are also provided in Table 4.1. This analysis updates all of the input data to reflect current values and modifies the classification of distribution mains to be 75% demand related and 25% customer related. The detailed results for the 2001 Application Cost of Service analysis are presented under Tab 9, Section B, pages 1 – 4.

As in the 2001 Baseline study, the margin to cost ratio and revenue to cost ratio results from the 2001 Application study generally show movement towards unity (or 100% margin or revenue to cost ratio) from the 1996 Settlement Cost of Service analysis.

The results of the Cost of Service analyses do not demonstrate a present need for revenue shifting between customer rate classes, particularly in the context of an expanded zone of reasonableness. The class-by-class margin to cost ratios under either of the aforementioned costing methodologies are similar to the results from the 1996 Settlement case. Under the 2001 Application Cost of Service analysis methodology, the Residential class revenue to cost ratio is 96.5% and is well within the 90% - 110% acceptable range. Similarly, Rate Schedule 2 margin to cost rates and revenue to cost ratios fall within the 90% to 110% acceptable range. The Rate Schedule 3/23 margin to cost and revenue to cost ratios are 118.2% and 105.1% respectively. BC Gas believes these ratios fall within the zone of reasonableness, particularly having regard to the current gas price environment. The current margin to cost ratio of the general firm Rate Schedule 5/25 is 123.3% in the Application Cost of Service analysis. BC Gas recognizes this ratio is not within the 90% – 110% range but notes this ratio has moved closer to unity.

The industrial Rate Schedules 22A and 22B have experienced somewhat different changes in their respective margin to cost ratios. Although Rate Schedule 22A has experienced a decline in its margin to cost ratio from to 93.4%, it is still within the acceptable range. Rate Schedule 22B has remained largely unchanged at 110.0%.

TABLE 4.1
MARGIN TO COST RATIOS

Distribution Allocation	1996 Settlement 100 – 0	2001 Baseline Cost of Service analysis 100 – 0	2001 Application Cost of Service analysis 75 – 25
BC Gas TOTAL	100.0%	100.0%	100.0%
Rate Schedule 1	91.4%	94.8%	92.0%
Rate Schedule 2	96.1%	100.4%	104.2%
Rate Schedule 3 & 23	103.9%	107.6%	118.2%
Rate Schedule 5 & 25	137.5%	113.0%	123.3%
Rate Schedule 6	67.3%	100.7%	102.1%
Rate Schedule 22A	108.8%	93.4%	93.4%
Rate Schedule 22B	111.3%	110.0%	110.0%

REVENUE TO COST RATIOS

Distribution Allocation	1996 Settlement 100 – 0	2001 Baseline Cost of Service analysis 100 – 0	2001 Application Cost of Service analysis 75 – 25
Rate Schedule 1	95.3%	97.8%	96.5%
Rate Schedule 2	98.2%	100.1%	101.5%
Rate Schedule 3	101.6%	102.2%	105.1%
Rate Schedule 5	N/A	99.9%	102.1%
Rate Schedule 6	74.3%	100.3%	101.0%

Note: the references to 100 - 0 and 75 - 25 relate to the means of classifying distribution mains.

4.3 POSTAGE STAMP / REGIONAL RATES

BC Gas also prepared preliminary regional cost of service studies to address the issue of postage stamp rates. BC Gas charges postage stamp rates for gas delivery service in the Lower Mainland, Inland and Columbia Service Areas. This means that all customers within the same rate class pay the same amount for gas delivery service regardless of where they are geographically located in the Province. While gas commodity costs currently feature some differentiation in prices (Lower Mainland customers pay the higher cost of Westcoast Energy Transportation to the Lower Mainland), gas cost allocations issues are beyond the scope of this Application. This Application addresses BC Gas delivery costs only.

The appropriateness of the current postage stamp rate design has been explored in prior proceedings. The primary arguments in support of postage stamp rates are that postage stamp rates are seen to be a fair and equitable way to recover costs of delivery service from all customers, as well as easy to administer and understand. Arguments in favor of regionally differentiated rates are based primarily on differences in the cost of service across different regions. Thus a decision to depart from postage stamp rates requires an assessment of the degree to which costs vary across regions versus the benefits realized through the use of postage stamp rates.

It is important to note that even in a regional approach, postage stamping will continue to exist within a particular region unless individual customer rates were established.

The preliminary regional cost of service studies (labeled “2001 Regional”, shown under Tab 9) prepared by BC Gas include the Lower Mainland (Vancouver to Hope), Inland North (Chetwynd to Savona), Inland South (Savona to West Kootenay) and Columbia regions. These are referred to as preliminary in that the differentiation made in the Cost of Service analyses between regions relates primarily to the allocation of transmission plant (as more fully described in Tab 9). The margin to cost ratios reflect a general allocation of transmission plant to a regions rate classes. This does not reflect the distance component of one customer class relative to another, and may understate the margin to cost ratios of bypass customers and overstate the margin to cost ratios for smaller volume customers.

The results of these regional Cost of Service analyses indicate that as expected there is some differentiation in the cost of service between the regions but that these differences are relatively small. In most cases, the range of revenue to cost ratios fall within the zone of reasonableness that would otherwise apply for the consolidated enterprise.

TABLE 4.2
REGIONAL MARGIN TO COST RATIOS

Rate	Lower Mainland	Inland South	Inland North	Columbia
Total	105.6%	80.6%	107.0%	92.1%
Rate Schedule 1	93.7%	78.5%	109.2%	87.1%
Rate Schedule 2	107.6%	82.0%	139.3%	95.0%
Rate Schedule 3/23	125.3%	83.7%	149.2%	102.8%
Rate Schedule 5/25	130.6%	94.3%	155.9%	109.2%
Rate Schedule 6	112.5%	61.0%	71.8%	N/A
Rate Schedule 25 Bypass	N/A	N/A	94.3%	N/A
Rate Schedule 22 Bypass	N/A	N/A	31.2%	N/A
Rate Schedule 22A	N/A	79.6%	130.3%	N/A
Rate Schedule 22B	N/A	N/A	N/A	109.3%
Rate Schedule 22A Bypass	N/A	N/A	42.2%	N/A

REGIONAL REVENUE TO COST RATIOS

Rate	Lower Mainland	Inland South	Inland North	Columbia
Rate Schedule 1	97.3%	89.5%	103.7%	94.1%
Rate Schedule 2	102.6%	92.6%	109.8%	98.2%
Rate Schedule 3	106.7%	94.4%	112.0%	100.9%
Rate Schedule 5	104.3%	92.4%	107.0%	98.9%
Rate Schedule 6	105.4%	76.4%	83.3%	N/A

The primary difficulty with preparing detailed regional cost of service analyses is that it is not possible or practical to record or capture all costs on a regional basis. It would be more appropriate to refine allocation of costs to better reflect the nature in which costs are incurred in serving regional communities versus larger urban centres such as Vancouver or Kelowna. The regional studies allocate most operating, maintenance and general and administration costs based on the number of customers or demand within the region. This averaging of costs ignores the economies of scale inherent in providing marketing, communications and community relations services to larger communities. The same is true for general and administrative expense or corporate support functions such as finance and human resources management. BC Gas has not made any adjustments in the regional studies for these items since the high level studies undertaken do not indicate material variations in regional costs. Any further adjustments for the above items would likely move the regional costs closer to the system wide average.

Another difficulty associated with relying on regional cost of service analyses relates to the reliance on high level average data when analyzing relatively small rate classes within regions. For example, Rate Schedules 3/23 in Inland North is composed of just 337 customers and in Columbia is composed of 84 customers. Rate Schedule 5/25 for the same region is composed of 36 and 12 customers respectively. With relatively small numbers of customers, a few customers within a region can distort the results (favorably or unfavorably) for the whole group. These anomalies are averaged out when cost of service results are prepared on a broader basis.

Finally, in evaluating the appropriateness of regional rates versus system wide postage stamp rates, it is important to recognize the benefits received by the regions from being served through a larger consolidated entity rather than a stand-alone utility. Some of these benefits are less easily quantified but need to be considered even if only on a qualitative basis. For example, regional areas benefit from lower costs of capital and insurance, greater purchasing power for materials and supplies and other benefits derived from the scope and scale of the consolidated utility.

BC Gas is of the view that all of the above factors argue in favor of continuing with the current postage stamp rate structure.

5.0 CONCLUSIONS

After carefully evaluating the criteria mentioned above, for each of BC Gas' rate classes, it was determined that no adjustments to class revenue levels are currently warranted. This is particularly so in the present natural gas commodity market environment. In addition, the Company believes that the current postage stamp approach to establishing gas delivery rates should be maintained. BC Gas proposes that the interim increases in rates pursuant to BCUC Order G-75-00 and effective January 1, 2001, be made permanent effective January 1, 2001.

RATE STRUCTURES - RESIDENTIAL

1.0 INTRODUCTION

This section focuses on the costs associated with the delivery of gas to BC Gas' residential and commercial customers and the pricing structures used to recover those costs.

2.0 ALIGNING RATES AND COSTS

The results of Cost of Service studies provide cost guidelines for use in evaluating class rate structures. The classified costs attributable to each of the classes of service within the Cost of Service study provide useful information in determining the level of customer, demand and delivery charges that are appropriate for each rate class. Costs by customer class are presented in Section A of Tab 9. A customer cost per month is calculated for each rate class as well as the unit demand and delivery costs.

A number of factors were considered in examining the alignment between rates and costs. They are outlined below.

1. Most of the costs of providing service to residential and commercial customers are fixed. The cost of serving a customer does not vary significantly with that customer's consumption unless the change in consumption causes the Company to incur costs to increase peak capacity. These fixed costs are reflected in the customer and demand-related costs.

2. The current rate structure for residential and commercial customers includes a basic charge and a per gigajoule delivery charge. For the residential customer class as a whole, approximately 25% of the utility's fixed costs are recovered through the basic charge. In other words, customer revenue is largely dependent on consumption even though the bulk of the costs of service are not. As a result, customers with above average consumption pay more than the Company's cost of serving them. Conversely, customers with below average consumption pay less than the Company's cost of serving them. Under the current rate structure, lower volume customers are being subsidized by the other customers.

3. High gas prices have pushed the efficiency adjusted delivered price to customers of gas to be close to parity with the comparable price for electricity. Motivated by the convergence in price, customers may increasingly choose electricity to heat their homes highlighting the shortcomings of the historic practice of recovering fixed gas distribution costs through variable charges.

3.0 CURRENT RESIDENTIAL RATE STRUCTURE

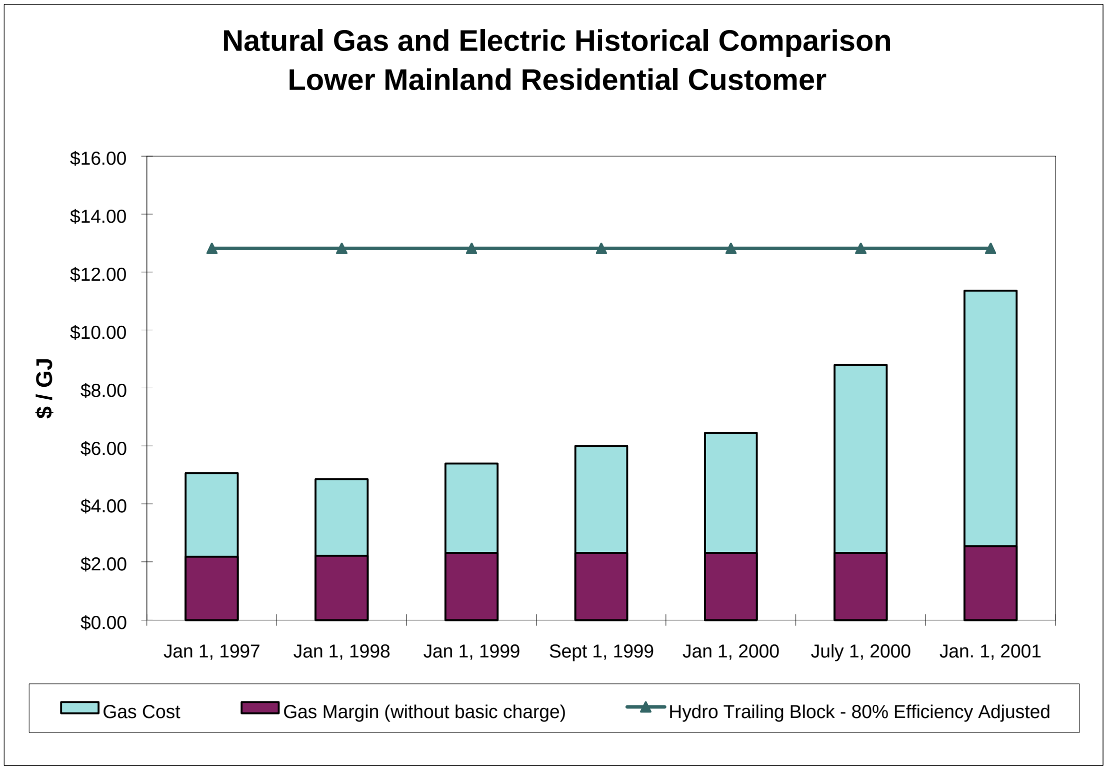
The 2001 Cost of Service studies (filed under Tab 9 of this Application) show the monthly fixed and variable costs of service for Rate Schedule 1 and other BC Gas rate classes. Study results for Rate Schedule 1 show that the residential customer-related costs are approximately $20 per customer per month and the demand-related costs are approximately $16 per customer per month. When combined, the customer-related and demand-related costs total over $36 per customer per month, representing the total fixed costs of providing service to residential customers. The commodity-related, or variable costs are about $0.05 per GJ (the gas commodity costs are in addition to this). The residential rate structure has a basic charge component and a per gigajoule delivery charge. The current monthly basic charge is $8.66, while the variable delivery charge is $2.632 per GJ, both exclusive of riders. The current basic charge recovers only 43% of the customer-related costs and only 24% of the customer-related and demand-related costs combined.

TABLE 5.1 RESIDENTIAL COST OF SERVICE AND CURRENT RATE STRUCTURE

Type of Charge	Cost of Service	Current Rates	Differences
Fixed Costs & Charges $ / month			
Customer-Related Costs	$20.19		
Demand-Related Costs	$16.25		
Total Fixed Costs Basic Charge	$36.44/mo	$8.66/mo	$27.78/mo
Delivery Cost & Charges $/GJ	$0.055/GJ	$2.632/GJ	$2.577/GJ

BC Gas compared its delivery and gas commodity charges to the comparable per kWh rate for electric service in the Lower Mainland. Assuming an 80% efficiency adjustment (this factor reflects the minimum standard for mid-efficiency furnaces of 78% and for high-efficiency furnaces of over 90%) for the natural gas rate, the comparative rate is $12.82 per GJ for electricity (based on $0.0577 per kWh multiplied by the conversion factor of 277.78 kWh per GJ multiplied by the 80% efficiency factor) versus the BC Gas rate of $11.047 per GJ (includes gas cost recovery charge of $8.415 per GJ and the delivery charge of $2.632 per GJ, excludes all riders). The variable delivered price of gas is only 14% less than the electric price. The marginal rate for gas is now only 86% of the electric trailing rate. If the existing riders are added into the analysis, the gas delivery charge increases by approximately $0.31 per GJ, reducing the differential to 11%. These levels compare with a January 1, 1999 delivered gas price of $5.441 per GJ or roughly 42% of the electric price. By comparison, if gas prices were restructured to reflect costs, the variable component of gas rates would be approximately 66% of the electric rate. Gas commodity prices would have to increase by roughly 50% for gas to be uncompetitive with electricity.

Based on current futures prices for gas, it is possible that the gas cost recovery charges for BC Gas' customers may have to increase an approximate 15% in the near future. An increase of this magnitude would increase the total rate for gas by approximately $1.26 per GJ up to $12.309 (excluding all riders), or 96% of the electric marginal rate. If riders are included in the rate for gas, this total will be $12.62 per GJ, or 98% of the electric rate. With these potential gas commodity increases, for all intents and purposes parity with electric will result. The graphic below demonstrates how the electric and natural gas rates have converged since 1997. At these rate levels, it is possible that electric baseboard heating may displace gas space heating resulting in an inefficient allocation of energy resources.



Notes:

1. The electric rate equals $12.82 per GJ for electricity (based on $0.0577 per kWh multiplied by the kWh to GJ conversion factor multiplied by an 80% efficiency factor).
2. The Gas Margin and Gas Cost include appropriate riders. The Basic Charge is not included.

BC Gas has undertaken a survey of basic charges for Canadian and American gas utilities to provide a basis for comparison of the basic charges currently in effect in B.C. The survey indicates that residential basic charges range from $7.00 to $14.00 per month, and that most Canadian utilities have higher residential basic charges than in B.C. BC Gas' residential basic charge falls in the low-range of basic charges in place in other jurisdictions in Canada. Full results of the survey are provided under Tab 10. BC Gas also compared its residential basic charge to those charged by other non-energy utilities within B.C. Monthly fixed charges for telephone service in the Lower Mainland are in the $23 to $28 range and cable television are roughly $24. This would suggest that increases to residential basic charges would not be inconsistent with fixed cost recovery in other jurisdictions or other similar utility applications.

4.0 RESIDENTIAL RATE STRUCTURE PROPOSALS

In the face of electric competition and the increasingly unbundled environment, BC Gas believes it is important to improve the alignment of rates with costs. When gas prices were at roughly 50% of the price of electricity, there was less requirement to ensure the BC Gas' rates were structured to recover the fixed costs with an appropriate basic charge. However, with the convergence of gas and electric rates, the rate structures should be changed, in principle, to align rates with costs in order to eliminate cross-subsidization within the rate class and to send the appropriate pricing signals within the energy market.

Notwithstanding the arguments in favor of introducing higher basic charges and lower delivery charges, there are several factors that constrain the ability to make these changes at this time. In particular, given fixed costs of $36 per month; an increase of $25 per month would be required to align the basic charge with costs. The magnitude of the change in the monthly basic charge required to move the rates more in line with cost is substantial particularly for smaller volume customers. In order to align rates with costs without causing unacceptable levels of customer impact would require a phased in approach. Also, current bills combine the gas delivery and commodity cost recovery charges. In the absence of a disaggregated bill, many customers will over estimate the actual bill impact of the rate changes since they will not be able to readily see the corresponding reduction in their delivery charges. Finally, BC Gas recognizes that, in the current gas cost environment, increases of this magnitude would be seen to be unacceptable to residential customers. Accordingly, BC Gas proposes no rate structure alignment be done to the residential rates at this time but the issue will be addressed again in the future in conjunction with the development of new bill formats and unbundling and in the context of a comprehensive Provincial energy strategy.

RATE STRUCTURES - COMMERCIAL

1.0 INTRODUCTION

This section focuses on the costs associated with the delivery of gas to BC Gas' commercial customers, and the pricing structures used to recover those costs. As described under Tab 3, BC Gas offers a Small Commercial Service (Rate Schedule 2), and Large Commercial Service (Rate Schedules 3/23), that apply to commercial, institutional or light industrial customers. Rate Schedule 2 applies to customers who consume less than 2,000 gigajoules (GJ) per year, and Rate Schedules 3/23 is restricted to customers using greater than 2,000 GJ per year. This volume threshold was established when rates were established in 1993. The break point reflected a natural grouping of small and large commercial customers based on volume and load factor.

In BC Gas' 1993 Rate Design proceeding, when the Commercial rate schedules were established, Rate Schedule 2 was more expensive than Rate Schedule 3 over all consumption levels. This created a problem for customers who would pay significantly higher average rates if their gas use fell below 2,000 GJ. While the savings in gas commodity costs were substantial and the customer's total bill was reduced due to the lower consumption, the higher average delivery charges on Rate Schedule 2 reduced these savings. This rate structure was seen as a disincentive to DSM measures. In the 1996 Rate Design Application, an economic break point was established between the two rate schedules at about 2,000 GJ per year. This meant that a customer who consumed 2,000 GJ per year was indifferent from an economic perspective as to the rate schedule under which service is received. Furthermore, if they used less than 2,000 GJ per year they would be better off on Rate Schedule 2 and conversely, they were better off on Rate Schedule 3 if their use exceeded 2,000 GJ per year.

As a result of the changes that have occurred in rates since 1997, particularly the increases in gas commodity costs, the economic break point has decreased to approximately 1,280 GJ per year. The disconnect between the minimum volume threshold for Rate Schedule 3/23 and the economic break point have caused some concern with customers who feel that the current rate structure erodes some of the savings they have achieved through DSM. The economic break point between Rate Schedule 2 and 3/23 can be addressed by adjusting the basic and delivery charges for each rate.

3.3 CURRENT COMMERCIAL RATES

The rate structure for Commercial services includes a monthly basic charge and a per GJ delivery charge (in addition to the per GJ gas cost recovery charge). The current monthly basic charges are set out below in Table 6.1. This table also summarizes the monthly customer-related and demand-related costs per customer (taken from the Cost of Service 2001 Application study under Tab 9). The total customer and demand-related costs are $75.05 per customer per month for Rate Schedule 2 and $605.25 per customer per month for Rate Schedule 3/23. The current basic charges for Rate Schedule 2 of $17.35 and for Rate Schedule 3/23 of $92.88 for Rate 3/23, represent only 23% and 15% of their respective total fixed costs.

TABLE 6.1

MONTHLY BASIC CHARGES AND COSTS FOR COMMERCIAL CUSTOMERS

Rate Class	Monthly Customer-Related Cost	Monthly Demand-Related Cost / Customer	Total Customer and Demand Related (Fixed) Costs	Current Monthly Basic Charge
Rate 2 – Small Commercial	$23.72	$51.33	$75.05	$17.35
Rate 3/23 – Large Commercial	$59.37	$545.88	$605.25	$92.88

The per GJ delivery cost for Rate Schedule 2 is $0.055 per GJ and $0.049 per GJ for Rate Schedule 3/23 (from the Cost of Service 2001 Application study). The current delivery charge for Rate Schedule 2 is $2.229 per GJ and $1.869 for Rate Schedule 3/23, both considerably greater than the delivery cost.

3.3 COMMERCIAL RATE STRUCTURE PROPOSALS

BC Gas proposes to restructure commercial service rates to achieve an economic break point between Rate 2 and 3/23 that approaches 2,000 GJ per year. In order to achieve an economic break point, delivery charges need to be reduced and basic charges increased. To achieve a breakpoint at 2,000 GJ per year would require the delivery charges to be decreased to $2.021 and $1.770 per GJ for Rates Schedules 2 and 3/23 respectively, while increasing monthly basic charges to $23 and $123 per month respectively. At these rates, smaller volume Rate Schedule 2 customers (<100 GJ per year) would see increases of about 8%. BC Gas believes that in the current gas price environment the bill impacts on lower volume customers required to move to an economic break point at 2,000 GJ would be too great at this time.

Targeting a slightly lower economic break point at approximately 1,700 GJ per year will moderate this impact. The rates associated with achieving a 1,700 GJ break point are summarized in Table 6.2. below. The basic charges for both rate classes are increased by about 20% and the delivery charges decreased by an amount that ensures the proposed rates are revenue neutral for the class as a whole. The proposed basic charges for small commercial service are reflective of those charged in other jurisdictions.

Under the existing rate structures, at a consumption level of 2,000 GJ per year, the average unit rate for Rate Schedule 2 exceeds that of Rate Schedule 3 by $0.25 per GJ. By making the proposed changes, the differential at 2,000 GJ between Rate Schedule 2 and Rate Schedule 3/23 is decreased to $0.09 per GJ. This represents the perceived disincentive to DSM under the current rate structures.

TABLE 6.2

CURRENT AND PROPOSED COMMERCIAL BASIC AND DELIVERY CHARGES

	Current	**Proposed**	**Increase $**
Basic Charges $/ month			
Rate 2 – Small Commercial	$17.35	$21.00	$3.65
Rate 3/23 – Large Commercial	$92.88	$112.00	$19.12
Delivery Charges $/GJ			
Rate 2 – Small Commercial	$2.229	$2.095	($0.134)
Rate 3/23 – Large Commercial	$1.869	$1.806	($0.063)

COMMERCIAL BILL IMPACT ANALYSIS

BC Gas analyzed the impact that the proposed rates design changes would have on Small and Large Commercial customers at various levels of annual consumption. To determine the changes to customers' annual bills, the Company determined the overall impact on the "burner-tip" price that includes the basic charge, the delivery charge and the commodity cost of gas, exclusive of all riders. For the purposes of this analysis, Rate Schedule 23 gas costs are assumed to be similar to those for Rate Schedule 3. The bill impact analysis results are found in Table 6.3 for Small Commercial (Rate Schedule 2) and Table 6.4 for Large Commercial customers (Rate Schedule 3/23).

TABLE 6.3

RATE SCHEDULE 2 MONTHLY BILL IMPACTS

Annual Consumption	Number of Customers	Current Average Monthly Bill ($/month)	Increase/ Decrease ($)	Increase/ Decrease (%)
0 – 100 GJ/year	28,137	$60	$3.11	5.2%
100 – 300 GJ/year	21,403	$191	$1.48	0.8%
300 – 700 GJ/year	12,436	$452	($1.79)	(0.4%)
700 plus GJ/year	11,125	$1,201	($11.14)	(0.9%)

TABLE 6.4

RATE SCHEDULE 3/23 MONTHLY BILL IMPACTS

Annual Consumption	Number of Customers	Current Average Monthly Bill ($/month)	Increase/ Decrease ($)	Increase/ Decrease (%)
1,800 – 2,600 GJ/year	1,906	$1,842	$8.13	0.4%
2,600 – 3,600 GJ/year	1,782	$2,555	$3.64	0.1%
3,600 – 4,600	941	$3,350	($1.35)	0%
4,600 plus GJ/year	1,492	$5,983	($17.90)	(0.3%)

BC Gas considers the bill impacts resulting from the increased basic charges and decreased delivery charges to be reasonable given the percentage and dollar impacts.

CONCLUSIONS

The proposed rates for Rate Schedule 2 and 3/23 move the rates more in line with costs and establish an economic crossover point closer to the 2,000 GJ Rate 3/23 threshold without significant adverse rate impacts on customers.

RATE STRUCTURES – INDUSTRIAL

1.0 INTRODUCTION

This section focuses on the Industrial service schedules described under Tab 3, Section 6.0. This Application does not addressed to gas sales or commodity pricing, with the exception of the matters addressed in Section 7.0 of this Tab. Rate Schedules 7, 10 and 14 Large Volume Interruptible and General Interruptible sales were dealt with in August 2000, with revisions approved by the Commission in September 2000, under order G-83-00. In addition, in response to the rapid and dramatic rise in natural gas costs, BC Gas recently filed an application which updated the costs of balancing, backstopping and UOR (unauthorized overrun) gas services as provided for in the Company's transportation tariffs (See details under Section 7.0 of this Tab).

2.0 SERVICE SCHEDULES AND PROPOSED REVISIONS

2.1 RATE SCHEDULE 5/25 – GENERAL FIRM SERVICE

Rate Schedule 5 is a bundled (commodity and transportation) firm service option available to small industrial and large commercial customers who wish to purchase natural gas from BC Gas and who typically have some type of process loads. Rate Schedule 25 is the companion firm transportation tariff under which customers receive only firm transportation service and purchase their gas requirements from a supplier other than BC Gas. Rates applicable for service under

Rate Schedules 5 and 25 are equal, except for the Transportation Service Administration Charge which applies to Rate Schedule 25 only.

The 1996 Rate Design Application and settlement introduced a demand/commodity rate structure to Rate Schedules 5 and 25 and the ability for customers or marketers to group gas supplies with other customers or groups of customers, for the benefit of gas contracting and managing gas imbalances.

BC Gas believes the existing rate structure is reasonable and proposes no changes at this time.

2.2 RATE SCHEDULE 6 – NATURAL GAS FOR VEHICLES (NGV)

Natural Gas Vehicle Service is available to customers who retail natural gas to customers with natural gas vehicles or fleet customers who use natural gas for their own fleet. Typical end-use applications include light, medium and heavy-duty vehicles and ferries. The average usage for this rate class ranges from 16,000 GJ in the Lower Mainland to 7,000 GJ per year in the Inland Service Area. Rate Schedule 6 includes a monthly basic charge and a variable delivery and gas cost recovery charge. No changes to Rate Schedule 6 are proposed at this time.

BC Gas is developing an additional NGV tariff for large NGV customers, including marine customers. The tariff will be designed to take into account the Utility’s associated costs and revenues as well as the prices of competing fuels. BC Gas proposes to submit a Large NGV and Marine Tariff in a supplemental information filing prior to the rate design hearing.

2.3 RATE SCHEDULE 7/27 – GENERAL INTERRUPTIBLE SALES AND TRANSPORTATION SERVICE AND RATE SCHEDULE 22 – LARGE VOLUME TRANSPORTATION

Rate Schedule 7 is a bundled (commodity and transportation) interruptible service option, available to small industrial and large commercial customers who wish to purchase their natural gas and interruptible delivery service from BC Gas and have the ability to curtail use during system capacity constraints. Rate Schedule 27 is the corresponding transportation service. Rate Schedules 7 and 27 are for use by small industrial and large commercial transportation customers with gas consumption of less than 12,000 GJ per month who have the ability and inclination to accept periodic curtailments of service.

For Rate Schedules 7 and 27 BC Gas proposes to retain the current rate structure and rates as filed and approved for January 1, 2001. The Company has strived to ensure its interruptible rates are reflective of the “value of service” provided, and also provide sufficient incentive to encourage customers to remain interruptible or consider switching to interruptible service.

Rate Schedule 22 provides transportation service (firm and/or interruptible) to large commercial and industrial customers with minimum monthly gas consumption of 12,000 GJ per month that do not qualify under Rate Schedule 22A or 22B. Customers requiring firm service are able to negotiate with BC Gas to determine the rates that should apply. The starting point for such negotiations is the rate available to Rate Schedule 5/25 customers.

At present, the majority of customers receiving service under Rate Schedule 22 are large volume interruptible customers who are able to curtail usage during the Company's peak operating conditions when delivery capacity is limited.

The rate design applications of the Company filed in 1993 and 1996 requested reductions in rates for this rate class. The Commission's decision in 1993 and the Settlement reached in 1996, approved these reductions. In this Application the Company has examined the relationship between firm and interruptible rates to ensure sufficient incentive exists to encourage customers to remain interruptible during periods when capacity is limited.

The objective of interruptible rate pricing is to establish a rate that provides a sufficient discount from the prevailing firm service rate to encourage those customers that can economically and operationally curtail their gas consumption during periods of peak throughput to do so. This ensures maximum utilization of existing capacity without having to construct infrastructure to serve interruptible loads. It is important to maximize value by establishing interruptible rates that make a significant contribution to the utility cost of service without encouraging truly interruptible customers from converting to firm service. If the interruptible rates are set too low relative to the anticipated level of curtailment, customers with truly firm service customers may elect to contract for interruptible service – effectively receiving firm service at a discount.

The factors that go into establishing the relationship between firm and interruptible rates in order to achieve an appropriate balance include:

1. the capital costs of purchasing and installing alternative fuel storage and delivery systems;

2. the customer’s capital costs of purchasing and retrofitting production equipment and appliances to accommodate alternative fuels;
3. the total net cost to the customer of the alternative fuel (i.e. adjusting for efficiency gains or losses);
4. the projected cost of gas during periods of curtailment, based upon the customers anticipated contracting practices (i.e. one year contracts vs. seasonal vs. monthly vs. daily pricing);
5. the opportunity cost, in the form of lost production and/or sales that may result as a consequence of curtailment; and
6. the actual frequency and duration of service curtailments ; a factor affected by weather and available capacity.

There are inter-relationships between the costs factors identified above. A material change in one or more components may, from time to time, necessitate changes to the Company’s firm and/or interruptible rates to ensure that the differential is sufficient to encourage customers that are capable of curtailing their gas requirements to do so or remain doing so. For example, if the efficiency adjusted cost difference between using natural gas and an alternative fuel narrows, customers can accept a greater number of days of curtailment or the Company can raise the rate for interruptible service and the customers will remain financially indifferent. Sometimes the differences between the cost of natural gas and alternative fuels can become so small that customers choose to burn alternative fuels instead of natural gas. This is not typical but recent changes in commodity markets suggest a much closer relationship between oil, propane and natural gas in terms of total net cost.

To determine whether the discounts reflected in the Company's current interruptible rates are acceptable, or whether changes to the relative level or structure of rates is warranted, BC Gas has examined the circumstances at the time of the 1996 Rate Design Settlement and the current environment.

In the 1996 Rate Design settlement the Rate Schedule 5/25 rates consisted of a demand charge of \$10.00/GJ per month of daily demand and a \$0.406/GJ commodity rate. The interruptible tolls set in accordance with this firm rate were at 100% load factor for Rate Schedule 22 interruptible customers; (\$0.539/GJ) and at 80% load factor for Rate Schedule 7/27 interruptible customers (\$0.674/GJ).

In 1996, based an average (55%) class load factor for Rate Schedule 5/25 customers, the discounts for interruptible service, relative to a typical firm customer's rates were:

R5/25 – R27 = \$1.002 – 0.674 = \$0.328/GJ

R5/25 – R22 = \$1.002 – 0.539 = \$0.463/GJ

The same comparison with the rates approved for January 1, 2001:

R5/25 – R27 = \$1.24 – 0.836 = \$0.404/GJ (for smaller volume customers)

R5/25 – R22 = \$1.24 – 0.666 = \$0.574/GJ (for larger volume customers)

Another basis for comparing the difference between firm and interruptible rates makes the comparison from an interruptible customers perspective by taking into account the customer's avoided cost of firm service based on its own distinct interruptible customers' load factor, <u>not</u> the average load factor of customers receiving service under Rate Schedules 5 and 25.

For example, the cost for a Rate Schedule 7/27 customer to convert to firm service, assuming a load factor based on the class average (about 63%), would result in the following:

	1996 ①		**2001②**	
A) Firm Cost	$0.5219	(Demand)③	$0.646	(Demand)③
	$0.4060	(Commodity)	$0.502	(Commodity)
	$0.928/ GJ		$1.148/GJ	
B) Interruptible Rate (rate 27)	$0.674①		$0.836②	
C) Differential	$0.254		$0.312	

① - Based on 1996 Settlement
② - Based on January 1, 2001 rates.
③ - Load Factor adjusted.

The corresponding analysis for Rate Schedule 22 customers, with an average class load factor of 72%, produces the following results:

	1996 ①		**2001②**	
A) Firm Cost	$0.457	(Demand)③	$0.565	(Demand)③
	$0.406	(Commodity)	$0.502	(Commodity)
	$0.863/ GJ		$1.0673/GJ	
B) Interruptible Rate (rate 22)	$0.539①		$0.666②	
C) Differential	$0.324		$0.401	

① - Based on 1996 Settlement
② - Based on January 1, 2001 rates.
③ - Load Factor adjusted.

Both analyses indicate that the gap between a customer’s firm service alternative and the interruptible rate under which it would receive service gas have increased substantially; i.e.

$0.058 per GJ or 23% for small volume customers and $0.077 per GJ or 24% for large volume customers.

A third comparison method looks at the firm and interruptible rates agreed to in 1996 with those prevailing today, comparing them at the 80% and 100% load factor rates for firm service (Rate Schedule 5/25) that were used in 1996 with the values achieved in 2001 using the same methodology. That comparison is:

	1996		2001	
R5/25	$0.329	(Demand)	$0.407	(Demand)
	$0.406	(Commodity)	$0.502	(Commodity)
	$0.735/ GJ		$0.909/GJ	
R22	$0.539		$0.666	
Differential	$0.196		$0.243	

	1996		2001	
R5/25	$0.411	(Demand)	$0.509	(Demand)
	$0.406	(Commodity)	$0.502	(Commodity)
	$0.817/ GJ		$1.011/GJ	
B) Rate 27	$0.674		$0.836	
C) Differential	$0.143		$0.175	

This comparison illustrates that interruptible customers with load factors in the 80-100% range are receiving relatively larger discounts today than those agreed to in the 1996 Rate Design Settlement.

As all these comparisons illustrate, there has been no deterioration between the avoided cost of firm service and the interruptible rates under which these customers are receiving service. In fact, the lower the load factor the larger the gap, in absolute terms, between the cost of firm and interruptible service.

Despite significant changes that have affected the cost of gas relative to the cost of alternative fuels, leading some customers to effectively "self-curtail" the use of natural gas for extended periods of extreme circumstances in favor of lower cost alternatives, BC Gas proposes to leave its interruptible service rates unchanged at this time. Based upon the foregoing analysis, the quality of service provided, and the volatility of commodity markets affecting natural gas and alternative fuels, the Company is unable to develop a legitimate basis for either increasing or decreasing interruptible rates at this time.

Since the 1996 Rate Design Settlement the Company has experienced no unusual or unanticipated migration activity (from firm to interruptible or interruptible to firm) that would suggest the rates or rate structure are producing undesirable effects on customer's service option selections.

BC Gas is of the view that the current interruptible rates achieve a reasonable balance between value maximization to offset firm customers' costs and provide a sufficient incentive to encourage new customers to convert to interruptible service and existing customers to stay interruptible.

2.4 RATE SCHEDULES 22A & 22B – LARGE VOLUME TRANSPORTATION SERVICES

These rate schedules are "closed" and are only available to Inland and Columbia service area industrial customers who were receiving service prior to 1993. The rate structure and rate setting methodology associated with each group of customers have been grandfathered in recognition of the unique service and cost allocation conditions that exist for each group.

In general, the terms and conditions of service for Rate Schedule 22 customers apply to Rate Schedules 22A and 22B customers; the notable exception being the peak shaving curtailment of firm service permitted under Rate Schedule 22A. Subject to a customer making alternative arrangements that provide BC Gas with peaking gas supplies, Rate Schedule 22A customers must make available one half of their firm supply and capacity to BC Gas for peak shaving purposes. BC Gas is permitted to draw on these supplies a maximum of 5 days in any one year or peak season.

For Rate Schedule 22A and 22B customers, BC Gas proposes to maintain the rate structure and the rates approved for January 1, 2001.

As indicated in Section 5.0, entitled “T-Service Administration Charge”, the Company recently filed and received approval to decrease Transportation Administration Charges for all transportation service customers including Rate Schedules 22A and 22B

3.0 SOUTHERN CROSSING PIPELINE SERVICES

BC Gas introduced a number of new services related to SCP through the Negotiated Settlement Process respecting the SCP Cost Allocation Application. BC Gas believes that these services have value for firm transport customers. While one month of experience (December) provides a limited basis to assess the success of these services, the initial results are encouraging.

In the month of December the use of the 15 Day peaking service, produced approximately $120,000 in economic value for two entities that were able to capture approximately $212,000 in economic value for movements of gas under Rate Schedule 40.

For the month of December, BC Gas has made significant use of the transportation functionality of the SCP sufficient to generate approximately $4.95 million of SCP mitigation during December 2000. Non-by-pass transportation customers will receive a share of this revenue applied against their total cost-of-service (i.e. $4,950,000 x 0.0836 = $413,000).

In aggregate these benefits total approximately $745,000 for the month of December alone.

4.0 BY-PASS SERVICE CONTRACTS

By-pass contracts are service agreements under which larger volume customers, located in close proximity to upstream transmission pipelines, have negotiated with BC Gas for delivery rates that are reflective of the customer’s cost of constructing it’s own direct pipeline. All by-pass contracts are approved by the BCUC. With the exception of the specific rate, the terms and conditions of service in by-pass contracts conform with the standard tariff under which the customer will be receiving service. Since the by-pass rates are established in an independent process, this Application contemplates no change to the service rates, terms and conditions applicable to by-pass customers.

5.0 T-SERVICE ADMINISTRATION CHARGE

All transportation customers pay a transportation service (T-Service) Administration Charge designed to recover the incremental costs incurred by BC Gas in providing its transportation service. Originally established in 1993, Administration Charges have seen several revisions. There were small increases in 1994, 1995 and 1996 and a significant reduction effective January 1, 1997 from $213 per month for Rate Schedule 25 and 27 and $608 per month for Rate Schedule 22/22A/22B to $105 per month. These reductions in the Administration Charges reflected lower administration costs resulting from new transportation service nomination and grouping guidelines. Since 1997, BC Gas has seen the number of transportation service customers increase and has been able to further reduce transportation service costs through improved processes and the resultant economies of scale. In an Application filed with the Commission in November 1999 BC Gas requested and received approval to further reduce the T-Service Administration Charge to $75 per month. Since November 1999, increases in the Administration Charge, reflecting Revenue Requirement adjustments, have increased the rate, effective January 1, 2001, to $87 per month. BC Gas is satisfied that the current Administration Charge adequately recovers the incremental costs associated with providing transportation service. As directed by the Commission, BC Gas will review the issue of administrative costs by September 30, 2002.

6.0 GROUPING/BALANCING

As part of the Company’s transportation terms and conditions, customers are permitted to join with other customers in a “group” in order to take advantage of the benefits that grouping creates, such as reduced gas management administration and improved load factors, thereby lowering overall gas costs, for all members of the group.

Balancing is a service the Company provides its transportation customers when actual gas consumption differs from the amount of gas transported on any day; i.e. if a customer ships less gas than is actually used, BC Gas will provide Backstopping or Balancing Gas.

For Large Volume (Rate Schedules 22, 22A and 23B) transportation customers, consumption is recorded daily and compared to the gas delivered on behalf of that customer to BC Gas on that day. Differences are considered to be imbalances. For Large Volume customers there is an unlimited amount of gas permitted for over deliveries; i.e. actual consumption is less than the amount of gas delivered. For under deliveries of less than 20%, the shortfall is made up from the gas held in an inventory account. For amounts greater than 20%, BC Gas makes the extra gas available as “Balancing Gas” at prevailing market prices.

Despite changing market forces that continue to increase the cost of handling customer imbalances, improvements in the timeliness of measurement records and the added line pack capacity provided by the Southern Crossing Pipeline make it possible for BC Gas to continue, at time, the current balancing terms and conditions of the transportation tariffs.

It is important to note that balancing is a service made possible by the availability of core market gas supply and storage resources. Shippers are expected to order and transport only those quantities of gas that “will equal the shipper’s best estimate…of the quantity of gas the shipper will actually consume…” Shippers over or under order gas supplies are effectively causing the core market to subsidize their gas procurement activities. As market volatility increases BC Gas will need to be more diligent in monitoring balancing practices with a view to introducing changes in tolerance levels if shipper ordering practices suggest tariff changes are needed.

7.0 BACKSTOPPING, BALANCING AND UNAUTHORIZED OVERRUN CHARGES – RATE SCHEDULES 4, 22, 22A, 22B, 23, 25 AND 27

7.1 BACKGROUND

On November 17, 2000, BC Gas applied to the Commission for revisions to the Backstopping, Balancing and Unauthorized Overrun (UOR) charges in the above noted Rate Schedules. It was the view of BC Gas that given the price volatility in the natural gas market, the Rate Schedule 1 and 5 Gas Cost Recovery Charges were significantly below prospective market prices and the use of the above noted services would have likely led to a cross subsidization form core market customers to transportation customers.

Pursuant to Order No. G-110-00, effective December 1, 2000, charges for backstopping, balancing and UOR were changed to reflect the Gas Daily NW Sumas Midpoint price. Order G-110-00 directed BC Gas to address appropriate charges for these items in this Application. BC Gas agrees with the Commission's view that the Midpoint price may not adequately compensate core market customers for the gas and services provided. Furthermore if price levels are inadequate, these services may be regarded by some shippers as simply the low cost alternative source of gas rather than a source of last resort if the charges associated with these services are aligned to the midpoint price.

In addition, with a view to market unbundling and how it will be structured for residential and small commercial customers, BC Gas wishes to align its current service offerings with the anticipated unbundled offerings. For example, the Market Unbundling Group (MUG), which submitted a report to the BCUC on August 6, 1999, suggested that charges for services such as backstopping should be set sufficiently high so as to discourage inappropriate use (Section 5.2.8). This view was endorsed by a cross-section of the market participants.

7.2 REVISIONS TO CHARGES

BC Gas requests these charges be revised to reflect the Gas Daily NW Sumas Common high price (i.e. the high price in the Common price range given) as set out under Table 7.1, Table 7.2 and Table 7.3 below. It is the Company's view that the Common high price will provide a reasonable deterrent to the use of these services under normal circumstances, and adequately compensate core market customers for gas provided under these services.

Table 7.1 Backstopping Charges

Rate Schedule(s)	Service Area	Charge for Backstopping Gas (USD Per MMBtu) Effective Dec. 1, 2000	Charge for Backstopping Gas (USD Per MMBtu) Requested
22, 23, 25, 27	Lower Mainland	Gas Daily NW Sumas Midpoint Price	Gas Daily NW Sumas Common High Price
22, 22A, 23, 25, 27	Inland	Gas Daily NW Sumas Midpoint Price	Gas Daily NW Sumas Common High Price
23, 25, 27	Columbia	Gas Daily NW Sumas Midpoint Price	Gas Daily NW Sumas Common High Price

Table 7.2 Charges for Balancing Gas

Rate Schedule(s)	Service Area	Balancing Gas (USD Per MMBtu) Effective Dec 1, 2000	Balancing Gas (USD Per MmBtu) Requested
22 22, 22A 22	Lower Mainland Inland Columbia	Gas Daily NW Sumas Midpoint Price	Gas Daily NW Sumas Common High Price
23, 25, 27	Lower Mainland Inland Columbia	Gas Daily NW Sumas Midpoint Price Average for the month	Gas Daily NW Sumas Common High Price Average for the month

Table 7.3 Unauthorized Overrun Charges

		UOR Charges (USD Per MMBtu unless otherwise stated) Effective December 1, 2000		**Requested UOR Charges (USD Per MMBtu unless otherwise stated)**	
Rate Schedule(s)	Service Area	First 5%	Over 5%	First 5%	Over 5%
7, 22, 23, 25, 27	Lower Mainland	Gas Daily NW Sumas Midpoint Price	Greater of: (CAD$20.00/GJ; Gas Daily NW Sumas Midpoint price X 1.5)	Gas Daily NW Sumas Common High Price	Greater of: (CAD$20.00/GJ; Gas Daily NW Sumas Common High price X 1.5)
7, 22, 22A, 23, 25, 27	Inland	Gas Daily NW Sumas Midpoint Price	Greater of: (CAD$20.00/GJ; Gas Daily NW Sumas Midpoint price X 1.5)	Gas Daily NW Sumas Common High Price	Greater of: (CAD$20.00/GJ; Gas Daily NW Sumas Common High price X 1.5)
7, 22, 22B, 23, 25, 27	Columbia	Gas Daily NW Sumas Midpoint Price	Greater of: (CAD$20.00/GJ; Gas Daily NW Sumas Midpoint price X 1.5)	Gas Daily NW Sumas Common High Price	Greater of: (CAD$20.00/GJ; Gas Daily NW Sumas Midpoint price X 1.5)
4	All Service Areas	Greater of: (CAD$20.00/GJ; Gas Daily NW Sumas Midpoint price X 1.5)	Greater of: (CAD$20.00/GJ; Gas Daily NW Sumas Midpoint price X 1.5)	Greater of: (CAD$20.00/GJ; Gas Daily NW Sumas Midpoint price X 1.5))	Greater of: (CAD$20.00/GJ; Gas Daily NW Sumas Midpoint price X 1.5)

GENERAL TERMS AND CONDITIONS

BC Gas proposes to make the following revisions to the General Terms and Conditions.

1.0 DEFINITIONS IN GENERAL TERMS AND CONDITIONS

BC Gas proposes that the following definition of "Operating Fees" be added to the Definitions in the General Terms and Conditions.

> Operating Fees – Has the same meaning as Franchise Fees.

"Operating Fees" will be a better term to use than "Franchise Fees" if BC Gas makes payments to municipalities under Operating Agreements which provide for the use of municipal streets and other property to construct and operate the distribution facilities of BC Gas. It is for the reason that a definition of the term is being added.

2.0 SECTION 5.1

Section 5.1 of the General Terms and Conditions be revised by adding to that section the following:

> If an applicant for Service at a Premises where Service has been disconnected applies for Service and fails to provide access to the Premises when BC Gas attends at the Premises to re-activate Service, then the applicant must pay the costs incurred by BC Gas that arise from the failure to provide access to the Premises. If an applicant for Service at a Premises where Service has been disconnected applies for Service after 2:00 pm on a

weekday and requests that Service be re-activated on that that day, or applies for Service and requests that Service be re-activated on a weekend or on a statutory holiday, then in addition to the applicable application and Service Line installation fees the applicant must pay the costs BC Gas incurs in re-activating the Service.

The revisions to Section 5.1 are intended to allow BC Gas to charge costs associated with re-activation of service when the request for re-activation is late in the day and service is requested on the same day, or when re-activation is requested on a weekend. The revisions are also intended to allow BC Gas too charge for re-activation when access is not provided to a Premises.

2.0 NEW SECTION 27 - ARBITRATION

BC Gas proposes a new Section be added to the General Terms and Conditions to provide for arbitration of disputes that are outside the jurisdiction of the Commission.

27.1 Any claim, dispute or controversy (whether in contract or tort, pursuant to statute or regulation, or otherwise, and whether pre-existing, present or future) between any Customer and BC Gas, or any Person claiming through the Customer, and arising out of or in any manner relating to Service, or lack of Service, or relating to any oral or written statements by BC Gas or its representatives (collectively the "Claim"), will be referred to and determined by binding arbitration (to the exclusion of the courts), provided, however, that nothing in this provision will deprive the British Columbia Utilities Commission of its jurisdiction to deal with, adjudicate and resolve any Claims between the Customer (or any Person claiming through the Customer) and BC Gas pursuant to the Utilities Commission Act of

British Columbia in respect of Claims which would otherwise fall within its jurisdiction. This Section shall not apply to the collection of any overdue accounts or other receivables owed by a customer to BC Gas with respect to any Service provided by BC Gas, and BC Gas shall be entitled to pursue any remedies provided by law with respect to the collection of overdue accounts or other receivables.

27.2 If a Customer or other Person has a Claim notice to arbitrate should be given to BC Gas by delivering the notice to BC Gas at 24th Floor, 1111 West Georgia Street, Vancouver, BC, V6E 4M4, Attention: Corporate Secretary. If BC Gas has a Claim it will give notice to arbitrate at the address of the Customer or other Person. Arbitration of Claims will be conducted in such forum and pursuant to such rules as BC Gas and the other party(ies) to the Claim agree upon, and failing agreement will be conducted by one arbitrator pursuant to the laws and rules relating to commercial arbitration in British Columbia that are in effect on the date of the notice to arbitrate. Arbitration of Claims will be to the exclusion of participation in any class action related to any Claim.

The General Terms and Conditions do not include an arbitration provision although the agreements associated with industrial Rate Schedules provide for arbitration. BC Gas proposes to include an arbitration provision in the General Terms and Conditions to make it clear that all disputes (other than collection of receivables) which are outside the jurisdiction of the Commission will be decided by arbitration and not decided in the courts. As set out in the proposed wording, matters which are within the jurisdiction of the BCUC will continue to be within its jurisdiction.

COST OF SERVICE STUDY

1.0 INTRODUCTION

The Cost of Service study performed for this rate design application employs, except as noted herein, the same methodology as the Cost of Service analysis filed by BC Gas in the 1996 Rate Design Application. As in the 1996 Cost of Service analysis, BC Gas' 2001 studies employ a coincident peak methodology and classify a portion of the investment in distribution mains as customer related. In addition, BC Gas has continued to use the minimum system methodology as in prior years for determining the customer related portion of distribution mains. Consistent with previous studies, capacity related costs are not allocated to interruptible customer classes and a consistent approach has been used for allocating general and administrative costs.

The 1996 Rate Design Settlement Agreement was based on the results of a cost of service analysis classifying 100% of distribution mains as demand related. This varies from the approach set out in BC Gas' 1996 Application. In recognition of that provision in the 1996 Settlement Agreement, the results from classifying distribution mains as 100% demand related in the 2001 cost of service study, labeled "2001 Baseline" are provided in Section A, pages 1 – 4. By maintaining a consistent methodology between the 1996 and 2001 analyses, it is easier to compare how revenue to cost ratios have changed since the last review (see Tab 4, Table 4.1). This establishes the baseline against which to compare the results for the current Application study that uses a different methodology for allocating distribution mains costs.

The Cost of Service analysis in this Application labeled "2001 Application" classifies 25% of distribution mains investment as customer related, based on the results of a minimum system method for determining the customer component of distribution mains. The results of this approach are found in Section B, Pages 1 – 4. The rationale supporting this classification of distribution mains cost is provided in Section 3.1 below.

Changes in costs and revenues in the current studies relative to the 1996 studies reflect the 2000 forecast of consumption volumes, number of customers, and peak demand levels. Adjustments to the 2000 forecast values are described in Section 4 – Adjustments to the 2000 Annual Review Forecast. A significant addition for the Cost of Service analysis is the Southern Crossing Pipeline costs discussed under Tab 4, Section 2.2.

Regional cost allocation results have also been prepared based on the historical records regarding transmission and distribution plant. The results are provided for four regions: Lower Mainland (Vancouver to Hope), Inland North (Chetwynd to Savona), Inland South (Savona to West Kootenay) and Columbia regions. The regional Cost of Service study labeled “2001 Regional” (Section C) is based on segregating capital costs by the location of the plant. The assumption underlying the regional cost analysis is that the service provided by the plant is primarily related just to the customers in the region. The problem with this assumption is that the infrastructure may serve a broader base of customers through its impact on gas supply resourcing or gas cost mitigation efforts. In addition, some of the accounting records are not sufficiently detailed to specifically identify costs by location. Also the historical records are a ‘snapshot’ in time of what the costs were and do not reflect replacement costs nor support costs in the operations and maintenance of the system.

In the regional cost allocation, the Inland service area distribution costs were segregated based on

Inland North and Inland South’s respective contributions to peak demand and numbers of customers. None of the SCP costs were allocated to Inland North in the regional study. The results of the regional cost of service study are included in Section C of this Tab.

2.0 PROCEDURES INVOLVED IN COST OF SERVICE STUDIES

BC Gas has followed the traditional three steps in preparing fully distributed cost of service studies: 1) functionalization, 2) classification of functionalized 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. Classification is the separation of the functional groups into demand, commodity and customer components according to cost causation principles. 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.

2.1 CHART OF ACCOUNTS

The plant and revenue requirement records are the basic accounting data source for the fully distributed cost study. Where more detailed information was required to perform various subsidiary analyses related to certain plant and expense elements, the data were derived from the historical books and records of the Company.

2.2 FUNCTIONALIZATION

The functionalization process is based on data from the plant and operating expense accounts. The investment associated with each facility was assigned to a function (e.g. transmission, distribution, marketing, etc.). After assigning plant costs functionally, related expenses are generally also functionalized on the same basis.

2.3 CLASSIFICATION

The essential element in the development of a cost of service study is the establishment of relationships between customer requirements, load profiles and usage characteristics and the costs incurred by the Company in serving those requirements. For example, providing a customer with gas service during peak periods can have much different cost implications for the utility than service to a customer who requires service only during off-peak periods.

These relationships primarily focus on the design considerations of the gas distribution and transmission system. Specifically, the Company's system is designed to meet three primary objectives: (1) to provide service to all customers entitled to be attached to the system; (2) to meet the aggregate peak design day capacity requirements of all customers entitled to service on the peak day; and (3) to deliver volumes of natural gas to those customers either on a sales or transportation basis.

3.0 CATEGORIES OF COST

Approximately 60% to 65% of BC Gas' total costs relate to the cost of natural gas supplies purchased on behalf of sales customers. The remaining 35% - 40% of the costs that BC Gas incurs in serving its customers are to provide utility delivery service. These delivery service costs, called "cost of service margin" or "delivery margin," are the total cost to serve less the cost of gas. The Cost of Service study is confined to the allocation of delivery margin costs.

There are three primary categories of cost causation factors in utility operations: demand related costs, customer related costs, and delivery related costs. The first two cost categories are incurred in standing by to serve customers whenever they apply a load to the system. Delivery related costs vary with consumption of gas the additional costs are 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. Classification of costs, the second step of the Cost of Service, further separates the functionalized plant and expenses into the following three cost-defining characteristics of service: 1) customer; 2) demand or capacity; 3) throughput (delivery), as discussed below.

3.1 CUSTOMER RELATED COSTS

Customer related costs are incurred to attach a customer to the distribution system, meter any gas usage and maintain the customer's account. Customer costs are a function of the number of customers served and continue to be incurred whether or not the customer uses any gas. 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 may include capital costs associated with the investment in minimum size distribution mains, services, meters, house regulators as well as marketing and customer accounting activities. These costs are directly assigned in certain cases or are allocated to the customers of a particular class of service based on customer weighting factors.

The 1996 Settlement and 2001 Baseline studies assume mains costs are 100% demand related. However, this approach does not recognize that distribution mains are installed to meet both system peak load requirements and to connect customers to the gas distribution system. Therefore, to ensure that the rate classes that cause the investment in this plant are charged with its cost, distribution mains should be allocated to the rate classes in proportion to their peak period load requirements as well as number of customers.

There are two cost factors that influence the level of distribution mains facilities installed by a utility in expanding its gas distribution system. First, the size of the distribution main (i.e., the diameter of the main) is directly influenced by the sum of the peak period gas demands placed on the utility's gas system by its customers. Secondly, the total installed footage of distribution mains is influenced by the need to expand the distribution system grid to connect new customers to the system. Therefore, to recognize that these two cost factors influence the level of investment in distribution mains, it is appropriate to allocate such investment based on both peak period demands and the number of customers served by the utility.

In the 2001 Application study, BC Gas used the minimum system method to classify a portion of mains as customer-related. This method follows a commonly used practice in the utility industry. In the Lower Mainland Service Area, the customer-related portion is 24%, in the Inland service area it is 30% and in the Columbia Service Area 39%. The consolidated weighted-average is 26% (rounded to 25%) for all regions. Therefore, for the 2001 Application Study, BC Gas classified the mains cost as 25% customer-related.

3.2 DEMAND RELATED COSTS

The term demand (or capacity) refers to utility service that must be available upon the customer's demand. Demand or capacity related costs are associated with plant that is designed, installed and operated to meet maximum hourly or daily gas flow requirements, such as transmission and distribution mains. Gas supply-related resources also have a capacity related component of cost relative to the Company's requirements for serving daily peak demands and the winter peaking season.

Transmission and distribution capacity, compressor costs and storage (LNG) were 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 DELIVERY RELATED COSTS

Delivery related costs are those costs that vary with the gas delivered to customers. Few of the costs to operate the facilities of BC Gas are variable with respect to the volume of gas delivered to customers. Gas transportation, central and administration expenses are classified as delivery-related cost in these Cost of Service studies as a means to apportion the expenses to all sales and transportation service customers.

4.0 CAPACITY ALLOCATION

As in the 1987 Inland Rate Design, the 1993 Cost of Service analysis, and the 1996 Cost of Service analysis, the demand allocation factors for the firm industrial captive and bypass customers in the Inland service area are weighted by transmission distance. The Southern Crossing Pipeline cost, are allocated to all non-bypass customers, except large industrial transport customers in the Columbia Service Area (closed Rate Schedule 22B), based on peak demand.

For purposes of the 2001 Baseline and 2001 Application Studies, all load factors used in the capacity allocation process were reviewed. The Rate Schedule 1 load factor is 31% and the Rate Schedule 2 load factor is 29%. There are similar to the values reflected in the 1996 analysis. The load factors for Rate Schedules 3/23 and 5 have been revised to be 33% and 45% respectively. The revised load factors reflect the actual load factors for these rate schedules since 1996. Over that time period there has been significant migration of customers from Rate Schedule 3/23 to Rate Schedule 5/25 which has eroded the load factors from 1996 levels.

The coincident peak (CP) method is used in the 2001 Application Cost of Service analysis to allocate capacity costs according to the demand imposed on the system by the various classes of customers during the system peak day. The correlation between very cold weather and the firm system peak loads on the BC Gas system forms the basis of using the coincident peak method as a capacity cost allocator. BC Gas builds its system on the basis of having to deliver gas to firm customers under cold weather conditions. The Company must consistently rely upon the coincident peak day demand in the acquisition of its upstream gas supply-related resources and in the design of its own transmission and distribution facilities required to service its firm service customers.

The coincident peak method assigns the capital required to provide service during the peak load requirements of its customers. The coincident peak day demand directly measures the demand requirements of the Company's firm service customers, which create the need for the Company to reinforce or build additional transmission and distribution infrastructure.

5.0 2001 COST OF SERVICE STUDY PROFORMA ADJUSTMENTS

The Cost of Service input values reflect the BC Gas Revenue Requirement for the year 2000 forecast as filed and approved by Commission Decision and Order No. G-135-99 dated December 21, 1999. This information has been adjusted to reflect material changes in cost, revenue and customer data that could influence the results of the allocation process. The proforma adjustments include:

1. Centra Gas/Pacific Coast Energy Corp. (PCEC) revenue of $3,829,000 has been moved from Other Revenue to Transportation Revenue. The $3.8MM is for the transportation service of wheeling Centra’s gas from Huntingdon to Eagle Mountain Custody Transfer Station.

2. Pro-forma adjustments have been made for the annualized costs related to two CPCN’s – Southern Crossing Pipeline and the Fraser Valley Compressor Station. The Fraser Valley Compressor station costs have been included in the transmission costs. The Southern

Crossing Transmission Pipeline costs as mentioned earlier are allocated to all captive customers based on peak demand except the Columbia Service Area large industrial transport customers, Rate Schedule 22B.

3. The cost of gas in the Cost of Service analysis is based on the approved cost of gas flow-through effective July 1, 2000 and is used for presenting revenue to cost ratios.

4. Rate Schedule 3/23 and Rate Schedule 5/25 revenues have been adjusted due to the migration of approximately 115 customers from Rate Schedule 3/23 to Rate Schedule 5/25.

6.0 COST OF SERVICE STUDIES

The consolidated Cost of Service results for BC Gas are contained in Sections A and B under this Tab. Section A presents the Cost of Service 2001 Baseline results using a 100% demand component for distribution mains. Section B shows the Cost of Service 2001 Application results using a 25% customer component for distribution mains. Section C provides the results of the Cost of Service 2001 Regional analysis based on a 25% customer component for distribution mains.

Lines 60, 62 and 63 in Sections A and B show the cost of service margin, margin to cost ratios and the revenue to cost ratios. Per-unit values of demand, customer and delivery related costs are shown on Lines122 to 125.

	A	B	C	G	H	J	K	N	Q	R	S	T	U	V
1	BC Gas Utility Ltd.													
2	2001 Cost of Service Study													
3	Distribution Mains Classified 100% Demand													
4	"2001 Baseline"													
5			(a)		(b)	(c)	(d)			(i)	(j)	(k)		
6	**BC Gas Consolidated**				**TOTAL COMPANY**	**Sched 1**	**Sched 2**	**Sched 3 & 23**	**Sched 5 & 25**	**Sched 4**	**Sched 7 & 27**	**Sched 6**	**Gen Firm T-Srvc. Bypass Schd 25**	**Large Volume T-Srvc. Sched 22**
7	REVENUES:													
8	Operating Revenues													
9		A. Sales Revenues			$1,035,824,787	$636,776,800	$184,571,900	$158,042,000	$48,359,288	$1,747,600	$1,421,299	$4,905,900	$0	$0
10		B. Transportation Revenues			$45,542,591	$0	$0	$4,652,500	$7,672,849	$0	$5,215,424	$0	$708,000	$10,179,511
11	Total Operating Revenues				$1,081,367,378	$636,776,800	$184,571,900	$162,694,500	$56,032,137	$1,747,600	$6,636,723	$4,905,900	$708,000	$10,179,511
12														
13	Less:	C. Cost of Gas			($670,108,478)	($391,584,500)	($123,552,200)	($112,619,500)	($36,728,952)	($1,343,900)	($1,200,234)	($2,756,500)	($8,000)	($6,600)
14	Net Operating Revenues				$411,258,900	$245,192,300	$61,019,700	$50,075,000	$19,303,185	$403,700	$5,436,489	$2,149,400	$700,000	$10,172,911
15														
16	**Gross Margin**				**$411,258,900**	**$245,192,300**	**$61,019,700**	**$50,075,000**	**$19,303,185**	**$403,700**	**$5,436,489**	**$2,149,400**	**$700,000**	**$10,172,911**
17														
18	**Margin Reconciliation Adjustment (MRA)**				**($699,369)**	**($455,898)**	**($113,457)**	**($93,107)**	**($35,891)**	**($751)**	**($10,108)**	**($3,996)**	**$0**	**($18,915)**
19														
20	**SCP & FV incremental increase**													
21		SCP	$47,553,103	11.93%	$47,553,103	$29,253,081	$7,280,058	$5,974,282	$2,302,999	$48,164	$648,610	$256,438	$0	$1,213,696
22		FV	$5,016,968	1.25%	$5,016,968	$3,071,577	$764,407	$627,300	$241,815	$5,057	$68,104	$26,926	$0	$127,438
23		Total	$52,570,071	13.19%	$52,570,071	$32,324,658	$8,044,465	$6,601,583	$2,544,814	$53,221	$716,714	$283,364	$0	$1,341,135
24	**Adjusted Gross Margin excl. MRA**				**$463,828,970**	**$277,516,958**	**$69,064,165**	**$56,676,583**	**$21,848,000**	**$456,921**	**$6,153,203**	**$2,432,764**	**$700,000**	**$11,514,046**
25														
26	**Adjusted Gross Margin incl. MRA**				**$463,129,601**	**$277,061,061**	**$68,950,708**	**$56,583,476**	**$21,812,108**	**$456,171**	**$6,143,094**	**$2,428,767**	**$700,000**	**$11,495,131**
27														
28	Cost of Service													
29		Operating and Maintenance												
30			Transmission		$4,561,400	$1,918,346	$641,763	$602,641	$226,661	$0	$0	$5,346	$818	$0
31			Storage		$796,470	$451,414	$150,778	$142,738	$50,267	$0	$0	$1,273	$0	$0
32			Transmission - SCP		$1,424,000	$787,480	$262,997	$249,128	$87,689	$0	$0	$2,222	$0	$0
33			Distribution		$16,384,125	$11,455,631	$2,341,170	$1,575,044	$566,102	$5,857	$18,903	$25,098	$33,188	$11,168
34			Customer Accounting		$18,109,857	$15,312,015	$1,912,789	$426,197	$175,248	$12,596	$40,651	$8,387	$2,857	$24,017
35			Gas Supply Administration		$303,442	$95,040	$29,563	$31,611	$17,465	$537	$7,325	$821	$1,674	$17,468
36			Marketing		$4,521,652	$3,039,255	$478,900	$219,881	$143,841	$2,111	$64,620	$2,721	$4,743	$38,178
37			O&M excluding General & Admin		$46,100,946	$33,059,181	$5,817,961	$3,247,240	$1,267,274	$21,102	$131,498	$45,869	$43,280	$90,831
38														
39			General & Admin		$85,551,765	$52,927,414	$12,987,106	$10,289,744	$3,700,908	$18,504	$59,720	$493,333	$110,690	$35,283
40		Total Operating and Maintenance			$131,652,712	$85,986,594	$18,805,067	$13,536,983	$4,968,183	$39,606	$191,218	$539,202	$153,971	$126,114
41														
42		Depreciation Expense			$68,618,921	$42,524,394	$10,238,544	$7,963,783	$2,876,138	$15,625	$50,428	$759,826	$82,618	$29,793
43		Other Amortization Expenses			$2,710,001	$1,707,920	$501,774	$443,418	$156,463	$1,235	$9,278	($270,119)	$5,885	$20,613
44														
45	Other Revenues													
46		A. Late Payment Charge			($852,000)	($554,062)	($160,664)	($137,274)	$0	$0	$0	$0	$0	$0
47		B. Revenue from Service Work			($4,045,000)	($2,630,492)	($762,779)	($651,729)	$0	$0	$0	$0	$0	$0
48		C. SCP Revenue			($12,730,000)	($7,039,757)	($2,351,086)	($2,227,102)	($783,908)	$0	$0	($19,863)	$0	$0
49		D.			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
50		Total Other Revenues			($17,627,000)	($10,224,311)	($3,274,530)	($3,016,105)	($783,908)	$0	$0	($19,863)	$0	$0
51														
52		Taxes other than Income Tax			$35,818,800	$21,845,257	$5,590,701	$4,505,972	$1,629,721	$6,638	$21,424	$183,945	$39,621	$12,657
53		Income Tax			$60,957,200	$37,885,291	$9,271,640	$7,354,520	$2,636,563	$18,620	$46,537	$308,114	$68,430	$25,500
54														
55		Earned Return												
56			Rate Base		$2,143,505,221	$1,332,020,966	$326,121,282	$258,104,006	$92,701,757	$652,474	$1,630,780	$10,797,097	$2,397,952	$893,581
57			Embedded Rate of Return		8.444%	8.444%	8.444%	8.444%	8.444%	8.444%	8.444%	8.444%	8.444%	8.444%
58		Earned Return			$180,998,968	$112,476,712	$27,537,892	$21,794,469	$7,827,796	$55,095	$137,704	$911,714	$202,485	$75,455
59														
60	**Cost of Service Margin**				**$463,129,601**	**$292,201,857**	**$68,671,089**	**$52,583,039**	**$19,310,956**	**$136,818**	**$456,589**	**$2,412,819**	**$553,009**	**$290,132**
61														
62	**Margin to Cost Ratio (L26 / L60)**				**100.0%**	**94.8%**	**100.4%**	**107.6%**	**113.0%**	**333.4%**	**N/A**	**100.7%**	**126.6%**	**N/A**
63	**Revenue to Cost Ratio ((L26 + L13) / (L60 + L13))**					**97.8%**	**100.1%**			**121.6%**		**100.3%**		

	A	B	C	G	W	X	Y	Z	AA	AC	AD
1	BC Gas Utility Ltd.										
2	2001 Cost of Service Study										
3	Distribution Mains Classified 100% Demand										
4	"2001 Baseline"										
5			(a)								
6	**BC Gas Consolidated**				**Gen Firm T-Srvc. Bypass Schd 22**	**Sched 22A**	**T-Srvc Bypass Sch 22A**	**Sched 22B**	**BC Hydro**	**PCEC**	**Other Byron Creek**
7	REVENUES:										
8	Operating Revenues										
9		A. Sales Revenues			$0	$0	$0	$0	$0	$0	$0
10		B. Transportation Revenues			$214,000	$4,873,000	$1,538,500	$2,087,807	$4,421,000	$3,829,000	$151,000
11	Total Operating Revenues				$214,000	$4,873,000	$1,538,500	$2,087,807	$4,421,000	$3,829,000	$151,000
12											
13	Less:	C. Cost of Gas			($9,000)	($47,000)	($71,000)	($181,093)	$0	$0	$0
14	Net Operating Revenues				$205,000	$4,826,000	$1,467,500	$1,906,714	$4,421,000	$3,829,000	$151,000
15											
16	**Gross Margin**				**$205,000**	**$4,826,000**	**$1,467,500**	**$1,906,714**	**$4,421,000**	**$3,829,000**	**$151,000**
17											
18	**Margin Reconciliation Adjustment (MRA)**				**$0**	**($8,973)**	**$0**	**($3,545)**	**$0**	**$0**	**$45,273**
19											
20	**SCP & FV incremental increase**										
21		SCP	$47,553,103	11.93%	$0	$575,774	$0	$0	$0	$0	$0
22		FV	$5,016,968	1.25%	$0	$60,456	$0	$23,886	$0	$0	$0
23		Total	$52,570,071	13.19%	$0	$636,230	$0	$23,886	$0	$0	$0
24	**Adjusted Gross Margin excl. MRA**				**$205,000**	**$5,462,230**	**$1,467,500**	**$1,930,600**	**$4,421,000**	**$3,829,000**	**$151,000**
25											
26	**Adjusted Gross Margin incl. MRA**				**$205,000**	**$5,453,257**	**$1,467,500**	**$1,927,055**	**$4,421,000**	**$3,829,000**	**$196,273**
27											
28	Cost of Service										
29		Operating and Maintenance									
30			Transmission		$17,511	$171,429	$11,257	$74,936	$544,347	$336,194	$10,149
31			Storage		$0	$0	$0	$0	$0	$0	$0
32			Transmission - SCP		$1,100	$33,386	$0	$0	$0	$0	$0
33			Distribution		$9,669	$102,850	$94,016	$55,463	$75,043	$14,786	$135
34			Customer Accounting		$8,035	$48,601	$44,427	$26,390	$35,461	$32,185	$0
35			Gas Supply Administration		$618	$10,745	$16,720	$7,022	$36,967	$29,867	$0
36			Marketing		$14,185	$119,448	$73,393	$41,907	$190,336	$88,133	$0
37			O&M excluding General & Admin		$51,117	$486,458	$239,814	$205,718	$882,155	$501,164	$10,285
38											
39			General & Admin		$97,072	$1,106,492	$142,146	$275,211	$2,030,029	$1,242,823	$35,291
40		Total Operating and Maintenance			$148,189	$1,592,950	$381,960	$480,929	$2,912,184	$1,743,988	$45,576
41											
42		Depreciation Expense			$82,977	$899,077	$145,767	$287,544	$1,624,269	$978,827	$59,311
43		Other Amortization Expenses			$2,408	$28,494	$20,913	$10,697	$38,378	$31,160	$1,482
44											
45	Other Revenues										
46		A. Late Payment Charge			$0	$0	$0	$0	$0	$0	$0
47		B. Revenue from Service Work			$0	$0	$0	$0	$0	$0	$0
48		C. SCP Revenue			($9,830)	($298,453)	$0	$0	$0	$0	$0
49		D.			$0	$0	$0	$0	$0	$0	$0
50		Total Other Revenues			($9,830)	($298,453)	$0	$0	$0	$0	$0
51											
52		Taxes other than Income Tax			$51,616	$501,896	$50,960	$183,390	$726,636	$444,852	$23,514
53		Income Tax			$67,439	$787,337	$89,844	$181,052	$1,362,219	$838,860	$15,235
54											
55		Earned Return									
56			Rate Base		$2,510,087	$27,590,264	$3,148,346	$7,199,473	$47,735,591	$29,395,758	$605,806
57			Embedded Rate of Return		8.444%	8.444%	8.444%	8.444%	8.444%	8.444%	8.444%
58		Earned Return			$211,953	$2,329,740	$265,848	$607,928	$4,030,824	$2,482,197	$51,155
59											
60	**Cost of Service Margin**				**$554,752**	**$5,841,040**	**$955,292**	**$1,751,541**	**$10,694,510**	**$6,519,884**	**$196,273**
61											
62	**Margin to Cost Ratio (L26 / L60)**				**37.0%**	**93.4%**	**153.6%**	**110.0%**	**41.3%**	**58.7%**	**100.0%**
63	**Revenue to Cost Ratio ((L26 + L13) / (L60 + L13))**										

	A	B	C	G	H	J	K	N	Q	R	S	T	U	V
1	BC Gas Utility Ltd.													
2	2001 Cost of Service Study													
3	Distribution Mains Classified 100% Demand													
4	"2001 Baseline"													
5			(a)		(b)	(c)	(d)			(i)	(j)	(k)		
6	**BC Gas Consolidated**				**TOTAL COMPANY**	**Sched 1**	**Sched 2**	**Sched 3 & 23**	**Sched 5 & 25**	**Sched 4**	**Sched 7 & 27**	**Sched 6**	**Gen Firm T-Srvc. Bypass Schd 25**	**Large Volume T-Srvc. Sched 22**
64														
65														
66														
67														
68	TOTAL OPERATIONS AND MAINTENANCE EXPENSES													
69		Demand			$74,162,244	$38,501,956	$12,857,023	$12,186,652	$4,350,197	$0	$0	$108,732	$139,373	$0
70		Customer			$57,196,068	$47,394,724	$5,920,192	$1,320,341	$601,092	$39,069	$183,893	$429,663	$12,924	$108,645
71		Delivery			$294,399	$89,915	$27,851	$29,990	$16,894	$537	$7,325	$807	$1,674	$17,468
72														
73	TOTAL DEPRECIATION EXPENSES													
74		Demand			$45,286,565	$23,548,092	$7,868,085	$7,435,375	$2,658,936	$0	$0	$66,219	$79,074	$0
75		Customer			$23,332,356	$18,976,302	$2,370,460	$528,408	$217,202	$15,625	$50,428	$693,607	$3,544	$29,793
76		Delivery			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
77														
78	TOT/	OTHER AMORTIZATION EXPENSES												
79		Demand			$2,166,242	$1,233,019	$412,214	$379,635	$126,163	$0	$0	$3,453	$3,904	$0
80		Customer			$6,758	$249,051	$19,651	$4,279	$1,791	$123	$396	($275,242)	$28	$234
81		Delivery			$537,000	$225,850	$69,910	$59,505	$28,509	$1,112	$8,882	$1,669	$1,953	$20,379
82														
83	TOTAL TAXES OTHER THAN INCOME TAXES													
84		Demand			$25,917,144	$13,641,940	$4,565,404	$4,279,197	$1,535,943	$0	$0	$37,920	$38,115	$0
85		Customer			$9,901,656	$8,203,316	$1,025,297	$226,774	$93,778	$6,638	$21,424	$146,025	$1,506	$12,657
86		Delivery			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
87														
88	TOTAL OTHER REVENUES													
89		Demand			($17,627,000)	($10,224,311)	($3,274,530)	($3,016,105)	($783,908)	$0	$0	($19,863)	$0	$0
90		Customer			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
91		Delivery			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
92														
93	TOTAL RATE BASE													
94		Demand			$1,407,129,765	$733,940,046	$245,169,518	$231,812,553	$82,775,154	$4,861	$4,341	$2,071,935	$2,291,903	$24
95		Customer			$675,461,738	$562,960,704	$70,059,867	$15,607,709	$6,419,389	$461,160	$1,489,123	$8,438,222	$104,656	$879,785
96		Delivery			$60,913,718	$35,120,215	$10,891,896	$10,683,744	$3,507,214	$186,454	$137,316	$286,941	$1,393	$13,773
97														
98	EARNED RETURN													
99		Demand			$118,818,948	$61,974,372	$20,702,273	$19,574,402	$6,989,588	$410	$367	$174,956	$193,530	$2
100		Customer			$57,036,426	$47,536,766	$5,915,900	$1,317,925	$542,057	$38,941	$125,742	$712,529	$8,837	$74,290
101		Delivery			$5,143,594	$2,965,574	$919,719	$902,142	$296,151	$15,744	$11,595	$24,229	$118	$1,163
102														
103	INCOME TAX													
104		Demand			$40,014,612	$20,873,520	$6,969,445	$6,605,576	$2,354,205	$139	$124	$59,126	$65,403	$1
105		Customer			$19,209,857	$16,012,999	$1,992,594	$444,554	$182,638	$13,160	$42,495	$240,800	$2,987	$25,106
106		Delivery			$1,732,731	$998,773	$309,601	$304,389	$99,720	$5,321	$3,919	$8,188	$40	$393
107														
108	**Cost of Service Margin**													
109		Demand			$288,738,754	$149,548,588	$50,099,914	$47,444,732	$17,231,124	$549	$490	$430,544	$519,400	$3
110		Customer			$166,683,122	$138,373,158	$17,244,094	$3,842,281	$1,638,558	$113,555	$424,378	$1,947,382	$29,825	$250,726
111		Delivery			$7,707,724	$4,280,111	$1,327,081	$1,296,026	$441,275	$22,714	$31,720	$34,893	$3,784	$39,403
112		Check total			$463,129,601	$292,201,857	$68,671,089	$52,583,039	$19,310,956	$136,818	$456,589	$2,412,819	$553,009	$290,132
113														
114														
115	Peak Demand					696,575	232,655	200,827	72,368	872	-	1,964	$0	-
116														
117	Customers (unweighted) times 12					8,143,608	864,204	76,944	8,280	696	1,140	624	-	432
118														
119	Throughput*99%					78,280,994	24,212,151	26,269,904	14,704,580	472,537	6,445,847	709,794	$0	15,372,004
120														
121														
122	**Unit Cost - Demand $ / GJ / Year**					**$214.69**	**$215.34**	**$236.25**	**$238.10**	**$0.63**	**N/A**	**$219.19**	**N/A**	**N/A**
123	**Unit Cost - Demand $ / Customer / Month**					**$18.36**	**$57.97**	**$616.61**						
124	**Unit Cost - Customer $ / Customer / Month**					**$16.99**	**$19.95**	**$49.94**	**$197.89**	**$163.15**	**$372.26**	**$3,120.80**	**N/A**	**$580.38**
125	**Unit Cost - Delivery $ / GJ**					**$0.055**	**$0.055**	**$0.049**	**$0.030**	**$0.048**	**$0.005**	**$0.049**	**N/A**	**$0.003**

	A	B	C	G	W	X	Y	Z	AA	AC	AD
1	BC Gas Utility Ltd.										
2	2001 Cost of Service Study										
3	Distribution Mains Classified 100% Demand										
4	"2001 Baseline"										
5			(a)								
6	**BC Gas Consolidated**				**Gen Firm T-Srvc. Bypass Schd 22**	**Sched 22A**	**T-Srvc Bypass Sch 22A**	**Sched 22B**	**BC Hydro**	**PCEC**	**Other Byron Creek**
64											
65											
66											
67											
68	TOTAL OPERATIONS AND MAINTENANCE EXPENSES										
69		Demand			$116,161	$1,242,081	$54,329	$316,039	$2,627,050	$1,622,493	$40,159
70		Customer			$31,410	$340,124	$310,911	$157,868	$248,166	$91,628	$5,417
71		Delivery			$618	$10,745	$16,720	$7,022	$36,967	$29,867	$0
72											
73	TOTAL DEPRECIATION EXPENSES										
74		Demand			$74,202	$774,301	$31,708	$219,800	$1,533,228	$946,937	$50,608
75		Customer			$8,775	$124,776	$114,059	$67,743	$91,041	$31,890	$8,703
76		Delivery			$0	$0	$0	$0	$0	$0	$0
77											
78	TOT/	OTHER AMORTIZATION EXPENSES									
79		Demand			$1,558	$14,284	($123)	$530	($5,971)	($3,688)	$1,263
80		Customer			$116	$1,674	$1,530	$1,683	$1,222	$5	$219
81		Delivery			$733	$12,536	$19,507	$8,485	$43,128	$34,844	$0
82											
83	TOTAL TAXES OTHER THAN INCOME TAXES										
84		Demand			$46,454	$461,928	$14,424	$147,588	$697,474	$430,767	$19,989
85		Customer			$5,162	$39,968	$36,535	$35,802	$29,162	$14,085	$3,525
86		Delivery			$0	$0	$0	$0	$0	$0	$0
87											
88	TOTAL OTHER REVENUES										
89		Demand			($9,830)	($298,453)	$0	$0	$0	$0	$0
90		Customer			$0	$0	$0	$0	$0	$0	$0
91		Delivery			$0	$0	$0	$0	$0	$0	$0
92											
93	TOTAL RATE BASE										
94		Demand			$2,237,497	$25,192,475	$950,809	$5,811,760	$45,963,572	$28,387,562	$515,755
95		Customer			$271,977	$2,388,888	$2,183,707	$1,378,729	$1,743,011	$984,761	$90,050
96		Delivery			$613	$8,901	$13,830	$8,984	$29,007	$23,435	$0
97											
98	EARNED RETURN										
99		Demand			$188,936	$2,127,269	$80,287	$490,749	$3,881,194	$2,397,064	$43,551
100		Customer			$22,966	$201,719	$184,394	$116,421	$147,181	$83,154	$7,604
101		Delivery			$52	$752	$1,168	$759	$2,449	$1,979	$0
102											
103	INCOME TAX										
104		Demand			$60,163	$718,912	$27,133	$146,154	$1,311,652	$810,089	$12,970
105		Customer			$7,260	$68,171	$62,316	$34,672	$49,740	$28,102	$2,265
106		Delivery			$16	$254	$395	$226	$828	$669	$0
107											
108	**Cost of Service Margin**										
109		Demand			$477,644	$5,040,321	$207,757	$1,320,861	$10,044,626	$6,203,662	$168,540
110		Customer			$75,689	$776,433	$709,746	$414,190	$566,511	$248,864	$27,733
111		Delivery			$1,419	$24,286	$37,789	$16,491	$83,373	$67,358	$0
112		Check total			$554,752	$5,841,040	$955,292	$1,751,541	$10,694,510	$6,519,884	$196,273
113											
114											
115	Peak Demand				-	26,873	-	20,700	$0	$0	$0
116											
117	Customers (unweighted) times 12				-	120	-	72	-	-	-
118											
119	Throughput*99%				-	9,455,660	-	4,401,333	$0	$0	$0
120											
121											
122	**Unit Cost - Demand $ / GJ / Year**				**N/A**	**$187.56**	**N/A**	**$63.81**	**N/A**	**N/A**	**N/A**
123	**Unit Cost - Demand $ / Customer / Month**										
124	**Unit Cost - Customer $ / Customer / Month**				**N/A**	**$6,470.27**	**N/A**	**$5,752.63**	**N/A**	**N/A**	**N/A**
125	**Unit Cost - Delivery $ / GJ**				**N/A**	**$0.003**	**N/A**	**$0.004**	**N/A**	**N/A**	**N/A**

	A	B	C	G	H	J	K	N	Q	R	S	T	U	V
1	BC Gas Utility Ltd.													
2	2001 Cost of Service Study													
3	Distribution Mains Classified 75% Demand & 25% Customer													
4	"2001 Application"													
5			(a)		(b)	(c)	(d)			(i)	(j)	(k)		
6	**BC Gas Consolidated**				**TOTAL COMPANY**	**Sched 1**	**Sched 2**	**Sched 3 & 23**	**Sched 5 & 25**	**Sched 4**	**Sched 7 & 27**	**Sched 6**	**Gen Firm T-Srvc. Bypass Schd 25**	**Large Volume T-Srvc. Sched 22**
7	REVENUES:													
8	Operating Revenues													
9		A. Sales Revenues			$1,035,824,787	$636,776,800	$184,571,900	$158,042,000	$48,359,288	$1,747,600	$1,421,299	$4,905,900	$0	$0
10		B. Transportation Revenues			$45,542,591	$0	$0	$4,652,500	$7,672,849	$0	$5,215,424	$0	$708,000	$10,179,511
11	Total Operating Revenues				$1,081,367,378	$636,776,800	$184,571,900	$162,694,500	$56,032,137	$1,747,600	$6,636,723	$4,905,900	$708,000	$10,179,511
12														
13	Less:	C. Cost of Gas			($670,108,478)	($391,584,500)	($123,552,200)	($112,619,500)	($36,728,952)	($1,343,900)	($1,200,234)	($2,756,500)	($8,000)	($6,600)
14	Net Operating Revenues				$411,258,900	$245,192,300	$61,019,700	$50,075,000	$19,303,185	$403,700	$5,436,489	$2,149,400	$700,000	$10,172,911
15														
16	**Gross Margin**				**$411,258,900**	**$245,192,300**	**$61,019,700**	**$50,075,000**	**$19,303,185**	**$403,700**	**$5,436,489**	**$2,149,400**	**$700,000**	**$10,172,911**
17														
18	**Margin Reconciliation Adjustment (MRA)**				**($699,369)**	**($455,900)**	**($113,457)**	**($93,107)**	**($35,892)**	**($751)**	**($10,108)**	**($3,997)**	**$0**	**($18,915)**
19														
20	**SCP & FV incremental increase**													
21		SCP	$47,553,103	11.93%	$47,553,103	$29,253,081	$7,280,058	$5,974,282	$2,302,999	$48,164	$648,610	$256,438	$0	$1,213,696
22		FV	$5,016,968	1.25%	$5,016,968	$3,071,577	$764,407	$627,300	$241,815	$5,057	$68,104	$26,926	$0	$127,438
23		Total	$52,570,071	13.19%	$52,570,071	$32,324,658	$8,044,465	$6,601,583	$2,544,814	$53,221	$716,714	$283,364	$0	$1,341,135
24	**Adjusted Gross Margin excl. MRA**				**$463,828,970**	**$277,516,958**	**$69,064,165**	**$56,676,583**	**$21,848,000**	**$456,921**	**$6,153,203**	**$2,432,764**	**$700,000**	**$11,514,046**
25														
26	**Adjusted Gross Margin incl. MRA**				**$463,129,601**	**$277,061,058**	**$68,950,708**	**$56,583,475**	**$21,812,108**	**$456,171**	**$6,143,094**	**$2,428,767**	**$700,000**	**$11,495,131**
27														
28	Cost of Service													
29		Operating and Maintenance												
30			Transmission		$4,561,400	$1,918,346	$641,763	$602,641	$226,661	$0	$0	$5,346	$818	$0
31			Storage		$796,470	$451,414	$150,778	$142,738	$50,267	$0	$0	$1,273	$0	$0
32			Transmission - SCP		$1,424,000	$787,480	$262,997	$249,128	$87,689	$0	$0	$2,222	$0	$0
33			Distribution		$16,384,125	$12,016,427	$2,183,663	$1,276,697	$463,779	$7,216	$23,290	$22,933	$25,532	$13,760
34			Customer Accounting		$18,109,857	$15,312,015	$1,912,789	$426,197	$175,248	$12,596	$40,651	$8,387	$2,857	$24,017
35			Gas Supply Administration		$303,442	$95,040	$29,563	$31,611	$17,465	$537	$7,325	$821	$1,674	$17,468
36			Marketing		$4,521,652	$3,039,255	$478,900	$219,881	$143,841	$2,111	$64,620	$2,721	$4,743	$38,178
37			O&M excluding General & Admin		$46,100,946	$33,619,976	$5,660,454	$2,948,892	$1,164,951	$22,460	$135,885	$43,703	$35,624	$93,422
38														
39			General & Admin		$85,551,765	$54,741,024	$12,479,199	$9,322,297	$3,370,333	$22,921	$73,979	$486,295	$85,802	$43,707
40		Total Operating and Maintenance			$131,652,712	$88,361,000	$18,139,653	$12,271,189	$4,535,284	$45,381	$209,864	$529,998	$121,425	$137,130
41														
42		Depreciation Expense			$68,618,921	$43,875,154	$9,859,249	$7,245,021	$2,629,697	$18,899	$60,998	$754,608	$64,169	$36,038
43		Other Amortization Expenses			$2,710,001	$1,777,117	$482,290	$406,692	$143,826	$1,402	$9,817	($270,385)	$4,945	$20,931
44														
45	Other Revenues													
46		A. Late Payment Charge			($852,000)	($554,062)	($160,664)	($137,274)	$0	$0	$0	$0	$0	$0
47		B. Revenue from Service Work			($4,045,000)	($2,630,492)	($762,779)	($651,729)	$0	$0	$0	$0	$0	$0
48		C. SCP Revenue			($12,730,000)	($7,039,757)	($2,351,086)	($2,227,102)	($783,908)	$0	$0	($19,863)	$0	$0
49		D.			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
50		Total Other Revenues			($17,627,000)	($10,224,311)	($3,274,530)	($3,016,105)	($783,908)	$0	$0	($19,863)	$0	$0
51														
52		Taxes other than Income Tax			$35,818,800	$22,497,612	$5,406,043	$4,160,202	$1,510,283	$8,204	$26,480	$181,133	$30,742	$15,644
53		Income Tax			$60,957,200	$38,997,300	$8,960,027	$6,761,671	$2,433,828	$21,325	$55,271	$303,803	$53,186	$30,660
54														
55		Earned Return												
56			Rate Base		$2,143,505,221	$1,371,086,827	$315,158,491	$237,304,143	$85,575,929	$747,278	$1,936,819	$10,646,034	$1,863,766	$1,074,392
57			Embedded Rate of Return		8.444%	8.444%	8.444%	8.444%	8.444%	8.444%	8.444%	8.444%	8.444%	8.444%
58		Earned Return			$180,998,968	$115,775,459	$26,612,187	$20,038,115	$7,226,087	$63,101	$163,546	$898,958	$157,378	$90,722
59														
60	**Cost of Service Margin**				**$463,129,601**	**$301,059,331**	**$66,184,919**	**$47,866,785**	**$17,695,097**	**$158,312**	**$525,975**	**$2,378,253**	**$431,845**	**$331,126**
61														
62	**Margin to Cost Ratio (L26 / L60)**				**100.0%**	**92.0%**	**104.2%**	**118.2%**	**123.3%**	**288.1%**	**N/A**	**102.1%**	**162.1%**	**N/A**
63	**Revenue to Cost Ratio ((L26 + L13) / (L60 + L13))**					**96.5%**	**101.5%**			**119.8%**		**101.0%**		

	A	B	C	G	W	X	Y	Z	AA	AC	AD
1	BC Gas Utility Ltd.										
2	2001 Cost of Service Study										
3	Distribution Mains Classified 75% Demand & 25% Customer										
4	"2001 Application"										
5			(a)								
6	**BC Gas Consolidated**				**Gen Firm T-Srvc. Bypass Schd 22**	**Sched 22A**	**T-Srvc Bypass Sch 22A**	**Sched 22B**	**BC Hydro**	**PCEC**	**Other Byron Creek**
7	REVENUES:										
8	Operating Revenues										
9		A. Sales Revenues			$0	$0	$0	$0	$0	$0	$0
10		B. Transportation Revenues			$214,000	$4,873,000	$1,538,500	$2,087,807	$4,421,000	$3,829,000	$151,000
11	Total Operating Revenues				$214,000	$4,873,000	$1,538,500	$2,087,807	$4,421,000	$3,829,000	$151,000
12											
13	Less:	C. Cost of Gas			($9,000)	($47,000)	($71,000)	($181,093)	$0	$0	$0
14	Net Operating Revenues				$205,000	$4,826,000	$1,467,500	$1,906,714	$4,421,000	$3,829,000	$151,000
15											
16	**Gross Margin**				**$205,000**	**$4,826,000**	**$1,467,500**	**$1,906,714**	**$4,421,000**	**$3,829,000**	**$151,000**
17											
18	**Margin Reconciliation Adjustment (MRA)**				**$0**	**($8,973)**	**$0**	**($3,545)**	**$0**	**$0**	**$45,276**
19											
20	**SCP & FV incremental increase**										
21		SCP	$47,553,103	11.93%	$0	$575,774	$0	$0	$0	$0	$0
22		FV	$5,016,968	1.25%	$0	$60,456	$0	$23,886	$0	$0	$0
23		Total	$52,570,071	13.19%	$0	$636,230	$0	$23,886	$0	$0	$0
24	**Adjusted Gross Margin excl. MRA**				**$205,000**	**$5,462,230**	**$1,467,500**	**$1,930,600**	**$4,421,000**	**$3,829,000**	**$151,000**
25											
26	**Adjusted Gross Margin incl. MRA**				**$205,000**	**$5,453,257**	**$1,467,500**	**$1,927,055**	**$4,421,000**	**$3,829,000**	**$196,276**
27											
28	Cost of Service										
29		Operating and Maintenance									
30			Transmission		$17,511	$171,429	$11,257	$74,936	$544,347	$336,194	$10,149
31			Storage		$0	$0	$0	$0	$0	$0	$0
32			Transmission - SCP		$1,100	$33,386	$0	$0	$0	$0	$0
33			Distribution		$8,535	$102,850	$94,016	$55,463	$75,043	$14,786	$135
34			Customer Accounting		$8,035	$48,601	$44,427	$26,390	$35,461	$32,185	$0
35			Gas Supply Administration		$618	$10,745	$16,720	$7,022	$36,967	$29,867	$0
36			Marketing		$14,185	$119,448	$73,393	$41,907	$190,336	$88,133	$0
37			O&M excluding General & Admin		$49,983	$486,458	$239,814	$205,718	$882,155	$501,164	$10,285
38											
39			General & Admin		$94,218	$1,106,492	$142,146	$275,211	$2,030,029	$1,242,823	$35,291
40		Total Operating and Maintenance			$144,202	$1,592,950	$381,960	$480,929	$2,912,184	$1,743,988	$45,576
41											
42		Depreciation Expense			$80,293	$899,077	$145,767	$287,544	$1,624,269	$978,827	$59,311
43		Other Amortization Expenses			$2,240	$28,494	$20,913	$10,697	$38,378	$31,160	$1,482
44											
45	Other Revenues										
46		A. Late Payment Charge			$0	$0	$0	$0	$0	$0	$0
47		B. Revenue from Service Work			$0	$0	$0	$0	$0	$0	$0
48		C. SCP Revenue			($9,830)	($298,453)	$0	$0	$0	$0	$0
49		D.			$0	$0	$0	$0	$0	$0	$0
50		Total Other Revenues			($9,830)	($298,453)	$0	$0	$0	$0	$0
51											
52		Taxes other than Income Tax			$49,737	$502,215	$50,895	$183,408	$727,370	$445,314	$23,518
53		Income Tax			$65,584	$787,337	$89,844	$181,052	$1,362,219	$838,860	$15,235
54											
55		Earned Return									
56			Rate Base		$2,436,306	$27,590,264	$3,148,346	$7,199,473	$47,735,591	$29,395,758	$605,806
57			Embedded Rate of Return		8.444%	8.444%	8.444%	8.444%	8.444%	8.444%	8.444%
58		Earned Return			$205,723	$2,329,740	$265,848	$607,928	$4,030,824	$2,482,197	$51,155
59											
60	**Cost of Service Margin**				**$537,949**	**$5,841,359**	**$955,227**	**$1,751,559**	**$10,695,244**	**$6,520,345**	**$196,276**
61											
62	**Margin to Cost Ratio (L26 / L60)**				**38.1%**	**93.4%**	**153.6%**	**110.0%**	**41.3%**	**58.7%**	**100.0%**
63	**Revenue to Cost Ratio ((L26 + L13) / (L60 + L13))**										

	A	B	C	G	H	J	K	N	Q	R	S	T	U	V
1	BC Gas Utility Ltd.													
2	2001 Cost of Service Study													
3	Distribution Mains Classified 75% Demand & 25% Customer													
4	"2001 Application"													
5			(a)		(b)	(c)	(d)			(i)	(j)	(k)		
6	**BC Gas Consolidated**				**TOTAL COMPANY**	**Sched 1**	**Sched 2**	**Sched 3 & 23**	**Sched 5 & 25**	**Sched 4**	**Sched 7 & 27**	**Sched 6**	**Gen Firm T-Srvc. Bypass Schd 25**	**Large Volume T-Srvc. Sched 22**
64														
66														
67														
68	TOTAL OPERATIONS AND MAINTENANCE EXPENSES													
69		Demand			$65,993,938	$33,896,517	$11,319,855	$10,726,073	$3,837,377	$0	$0	$95,681	$105,517	$0
70		Customer			$65,364,375	$54,374,568	$6,791,947	$1,515,126	$681,013	$44,844	$202,539	$433,511	$14,234	$119,661
71		Delivery			$294,399	$89,915	$27,851	$29,990	$16,894	$537	$7,325	$807	$1,674	$17,468
72														
73	TOTAL DEPRECIATION EXPENSES													
74		Demand			$40,638,058	$20,926,624	$6,992,612	$6,605,943	$2,367,024	$0	$0	$58,821	$59,882	$0
75		Customer			$27,980,862	$22,948,530	$2,866,637	$639,078	$262,672	$18,899	$60,998	$695,788	$4,287	$36,038
76		Delivery			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
77														
78	TOT/	OTHER AMORTIZATION EXPENSES												
79		Demand			$1,927,985	$1,098,617	$367,293	$337,249	$111,197	$0	$0	$3,076	$2,926	$0
80		Customer			$245,015	$452,650	$45,087	$9,938	$4,121	$290	$935	($275,130)	$66	$552
81		Delivery			$537,000	$225,850	$69,910	$59,505	$28,509	$1,112	$8,882	$1,669	$1,953	$20,379
82														
83	TOTAL TAXES OTHER THAN INCOME TAXES													
84		Demand			$23,668,100	$12,371,826	$4,140,518	$3,880,127	$1,394,517	$0	$0	$34,379	$28,881	$0
85		Customer			$12,150,700	$10,125,787	$1,265,525	$280,075	$115,766	$8,204	$26,480	$146,753	$1,861	$15,644
86		Delivery			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
87														
88	TOTAL OTHER REVENUES													
89		Demand			($17,627,000)	($10,224,311)	($3,274,530)	($3,016,105)	($783,908)	$0	$0	($19,863)	$0	$0
90		Customer			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
91		Delivery			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
92														
93	TOTAL RATE BASE													
94		Demand			$1,272,704,122	$658,137,482	$219,858,905	$207,810,660	$74,334,302	$4,861	$4,341	$1,857,725	$1,736,208	$24
95		Customer			$809,887,381	$677,829,130	$84,407,690	$18,809,738	$7,734,412	$555,963	$1,795,162	$8,501,368	$126,164	$1,060,595
96		Delivery			$60,913,718	$35,120,215	$10,891,896	$10,683,744	$3,507,214	$186,454	$137,316	$286,941	$1,393	$13,773
97														
98	EARNED RETURN													
99		Demand			$107,467,960	$55,573,555	$18,565,028	$17,547,667	$6,276,837	$410	$367	$156,868	$146,607	$2
100		Customer			$68,387,414	$57,236,330	$7,127,440	$1,588,306	$653,099	$46,946	$151,585	$717,861	$10,653	$89,557
101		Delivery			$5,143,594	$2,965,574	$919,719	$902,142	$296,151	$15,744	$11,595	$24,229	$118	$1,163
102														
103	INCOME TAX													
104		Demand			$36,189,188	$18,716,692	$6,249,570	$5,921,499	$2,114,041	$139	$124	$53,013	$49,546	$1
105		Customer			$23,035,282	$19,281,835	$2,400,856	$535,782	$220,067	$15,865	$51,228	$242,602	$3,600	$30,266
106		Delivery			$1,732,731	$998,773	$309,601	$304,389	$99,720	$5,321	$3,919	$8,188	$40	$393
107														
108	**Cost of Service Margin**													
109		Demand			$258,258,228	$132,359,519	$44,360,347	$42,002,452	$15,317,085	$549	$490	$381,976	$393,359	$3
110		Customer			$197,163,648	$164,419,700	$20,497,492	$4,568,306	$1,936,738	$135,049	$493,764	$1,961,384	$34,702	$291,719
111		Delivery			$7,707,724	$4,280,111	$1,327,081	$1,296,026	$441,275	$22,714	$31,720	$34,893	$3,784	$39,403
112		Check total			$463,129,601	$301,059,331	$66,184,919	$47,866,785	$17,695,097	$158,312	$525,975	$2,378,253	$431,845	$331,126
113														
114														
115	Peak Demand					696,575	232,655	200,827	72,368	872	-	1,964	$0	-
116														
117	Customers (unweighted) times 12					8,143,608	864,204	76,944	8,280	696	1,140	624	-	432
118														
119	Throughput*99%					78,280,994	24,212,151	26,269,904	14,704,580	472,537	6,445,847	709,794	$0	15,372,004
120														
121														
122	**Unit Cost - Demand $ / GJ / Year**					**$190.01**	**$190.67**	**$209.15**	**$211.65**	**$0.63**	**N/A**	**$194.46**	**N/A**	**N/A**
123	**Unit Cost - Demand $ / Customer / Month**					**$16.25**	**$51.33**	**$545.88**						
124	**Unit Cost - Customer $ / Customer / Month**					**$20.19**	**$23.72**	**$59.37**	**$233.91**	**$194.04**	**$433.13**	**$3,143.24**	**N/A**	**$675.28**
125	**Unit Cost - Delivery $ / GJ**					**$0.055**	**$0.055**	**$0.049**	**$0.030**	**$0.048**	**$0.005**	**$0.049**	**N/A**	**$0.003**

	A	B	C	G	W	X	Y	Z	AA	AC	AD
1	BC Gas Utility Ltd.										
2	2001 Cost of Service Study										
3	Distribution Mains Classified 75% Demand & 25% Customer										
4	"2001 Application"										
5			(a)								
6	**BC Gas Consolidated**				**Gen Firm T-Srvc. Bypass Schd 22**	**Sched 22A**	**T-Srvc Bypass Sch 22A**	**Sched 22B**	**BC Hydro**	**PCEC**	**Other Byron Creek**
64											
66											
67											
68	TOTAL OPERATIONS AND MAINTENANCE EXPENSES										
69		Demand			$110,767	$1,242,081	$54,329	$316,039	$2,627,050	$1,622,493	$40,159
70		Customer			$32,817	$340,124	$310,911	$157,868	$248,166	$91,628	$5,417
71		Delivery			$618	$10,745	$16,720	$7,022	$36,967	$29,867	$0
72											
73	TOTAL DEPRECIATION EXPENSES										
74		Demand			$70,571	$774,301	$31,708	$219,800	$1,533,228	$946,937	$50,608
75		Customer			$9,722	$124,776	$114,059	$67,743	$91,041	$31,890	$8,703
76		Delivery			$0	$0	$0	$0	$0	$0	$0
77											
78	TOT/ OTHER AMORTIZATION EXPENSES										
79		Demand			$1,332	$14,284	($123)	$530	($5,971)	($3,688)	$1,263
80		Customer			$175	$1,674	$1,530	$1,683	$1,222	$5	$219
81		Delivery			$733	$12,536	$19,507	$8,485	$43,128	$34,844	$0
82											
83	TOTAL TAXES OTHER THAN INCOME TAXES										
84		Demand			$43,910	$462,335	$14,441	$147,638	$698,272	$431,260	$19,996
85		Customer			$5,827	$39,879	$36,454	$35,770	$29,097	$14,054	$3,522
86		Delivery			$0	$0	$0	$0	$0	$0	$0
87											
88	TOTAL OTHER REVENUES										
89		Demand			($9,830)	($298,453)	$0	$0	$0	$0	$0
90		Customer			$0	$0	$0	$0	$0	$0	$0
91		Delivery			$0	$0	$0	$0	$0	$0	$0
92											
93	TOTAL RATE BASE										
94		Demand			$2,137,681	$25,192,475	$950,809	$5,811,760	$45,963,572	$28,387,562	$515,755
95		Customer			$298,012	$2,388,888	$2,183,707	$1,378,729	$1,743,011	$984,761	$90,050
96		Delivery			$613	$8,901	$13,830	$8,984	$29,007	$23,435	$0
97											
98	EARNED RETURN										
99		Demand			$180,507	$2,127,269	$80,287	$490,749	$3,881,194	$2,397,064	$43,551
100		Customer			$25,164	$201,719	$184,394	$116,421	$147,181	$83,154	$7,604
101		Delivery			$52	$752	$1,168	$759	$2,449	$1,979	$0
102											
103	INCOME TAX										
104		Demand			$57,652	$718,912	$27,133	$146,154	$1,311,652	$810,089	$12,970
105		Customer			$7,915	$68,171	$62,316	$34,672	$49,740	$28,102	$2,265
106		Delivery			$16	$254	$395	$226	$828	$669	$0
107											
108	**Cost of Service Margin**										
109		Demand			$454,910	$5,040,728	$207,774	$1,320,910	$10,045,425	$6,204,155	$168,546
110		Customer			$81,620	$776,344	$709,664	$414,157	$566,446	$248,833	$27,730
111		Delivery			$1,419	$24,286	$37,789	$16,491	$83,373	$67,358	$0
112		Check total			$537,949	$5,841,359	$955,227	$1,751,559	$10,695,244	$6,520,345	$196,276
113											
114											
115	Peak Demand				-	26,873	-	20,700	$0	$0	$0
116											
117	Customers (unweighted) times 12				-	120	-	72	-	-	-
118											
119	Throughput*99%				-	9,455,660	-	4,401,333	$0	$0	$0
120											
121											
122	**Unit Cost - Demand $ / GJ / Year**				**N/A**	**$187.58**	**N/A**	**$63.81**	**N/A**	**N/A**	**N/A**
123	**Unit Cost - Demand $ / Customer / Month**										
124	**Unit Cost - Customer $ / Customer / Month**				**N/A**	**$6,469.53**	**N/A**	**$5,752.19**	**N/A**	**N/A**	**N/A**
125	**Unit Cost - Delivery $ / GJ**				**N/A**	**$0.003**	**N/A**	**$0.004**	**N/A**	**N/A**	**N/A**

	A	B	C	D	E	F	H	I	L	O	P	Q	R	S
1	BC Gas Utility Ltd. - Regional Studies													
2	2001 Cost of Service Study													
3	Distribution Mains Classified 75% Demand & 25% Customer													
4	"2001 Regional"													
5			(a)			(b)	(c)	(d)			(i)	(j)	(k)	
6	**Lower Mainland**					**TOTAL REGION**	**Residential Schd 1**	**Small Comm. Sales Schd 2**	**Sched 3 & 23**	**Sched 5 & 25**	**Seasonal Schd 4**	**Gen. Interr Sales / Trans Srvc. Schd 7,27**	**NGV Schd 6**	**Gen Firm T-Srvc. Bypass Schd 25**
7	REVENUES:													
8	Operating Revenues													
9		A. Sales Revenues				$770,868,203	$465,693,800	$133,229,300	$129,819,800	$35,533,124	$980,600	$1,370,299	$4,241,280	$0
10		B. Transportation Revenues				$32,483,588	$0	$0	$4,442,500	$4,595,153	$0	$5,016,424	$0	$0
11	Total Operating Revenues					$803,351,791	$465,693,800	$133,229,300	$134,262,300	$40,128,278	$980,600	$6,386,723	$4,241,280	$0
12														
13	Less:	C. Cost of Gas				($501,875,147)	($288,628,900)	($89,426,600)	($92,600,100)	($26,918,314)	($735,900)	($1,156,234)	($2,402,500)	$0
14	Net Operating Revenues					$301,476,644	$177,064,900	$43,802,700	$41,662,200	$13,209,964	$244,700	$5,230,489	$1,838,780	$0
15														
16	**Gross Margin**					**$301,476,644**	**$177,064,900**	**$43,802,700**	**$41,662,200**	**$13,209,964**	**$244,700**	**$5,230,489**	**$1,838,780**	**$0**
17														
18	**Margin Reconciliation Adjustment (MRA)**					**($546,515)**	**($330,013)**	**($81,639)**	**($77,650)**	**($24,621)**	**($456)**	**($9,749)**	**($3,427)**	**$0**
19														
20	**SCP & FV incremental increase**													
21		SCP	$47,553,103		11.93%	$34,983,831	$21,124,985	$5,225,945	$4,970,569	$1,576,034	$29,194	$624,031	$219,378	$0
22		FV	$5,016,968		1.25%	$3,673,307	$2,218,126	$548,725	$521,910	$165,484	$3,065	$65,523	$23,035	$0
23		Total	$52,570,071			$38,657,137	$23,343,111	$5,774,670	$5,492,480	$1,741,518	$32,260	$689,554	$242,413	$0
24	**Adjusted Gross Margin excl. MRA**					**$340,133,781**	**$200,408,011**	**$49,577,370**	**$47,154,680**	**$14,951,482**	**$276,960**	**$5,920,044**	**$2,081,193**	**$0**
25														
26	**Adjusted Gross Margin incl. MRA**					**$339,587,267**	**$200,077,998**	**$49,495,730**	**$47,077,030**	**$14,926,861**	**$276,504**	**$5,910,295**	**$2,077,766**	**$0**
27														
28	Cost of Service													
29		Operating and Maintenance												
30			Transmission			$3,250,952	$1,338,551	$439,396	$480,252	$139,606	$0	$0	$4,515	$0
31			Storage			$592,274	$330,009	$108,330	$118,402	$34,419	$0	$0	$1,113	$0
32			Transmission - SCP			$1,106,930	$616,771	$202,463	$221,288	$64,327	$0	$0	$2,081	$0
33			Distribution			$11,640,279	$8,610,532	$1,571,785	$1,050,148	$319,422	$1,951	$22,611	$18,371	$0
34			Customer Accounting			$12,596,761	$10,657,400	$1,348,841	$330,220	$120,235	$3,342	$38,736	$6,206	$0
35			Gas Supply Administration			$217,284	$68,048	$20,777	$25,824	$11,496	$291	$6,954	$710	$0
36			Marketing			$3,143,678	$2,115,294	$334,131	$173,474	$108,621	$560	$76,967	$2,151	$0
37			O&M excluding General & Admin			$32,548,157	$23,736,606	$4,025,722	$2,399,609	$798,127	$6,143	$145,268	$35,146	$0
38														
39			General & Admin			$62,187,149	$40,784,178	$9,084,801	$7,639,347	$2,269,244	$6,689	$77,544	$395,811	$0
40		Total Operating and Maintenance				$94,735,306	$64,520,784	$13,110,523	$10,038,956	$3,067,371	$12,832	$222,812	$430,957	$0
41														
42		Depreciation Expense				$46,530,626	$30,638,312	$6,702,604	$5,540,352	$1,648,383	$5,215	$60,455	$569,889	$0
43		Other Amortization Expenses				$1,974,972	$1,340,517	$350,355	$335,019	$99,138	$704	$9,571	-$203,848	$0
44														
45	Other Revenues													
46		A. Late Payment Charge				($593,629)	($379,351)	($108,528)	($105,750)	$0	$0	$0	$0	$0
47		B. Revenue from Service Work				($2,818,343)	($1,801,026)	($515,252)	($502,066)	$0	$0	$0	$0	$0
48		C. SCP Revenue				($9,895,517)	($5,513,692)	($1,809,937)	($1,978,229)	($575,060)	$0	$0	($18,599)	$0
49		D. Bypass Customer Revenue				$0	$0	$0	$0	$0	$0	$0	$0	$0
50		Total Other Revenues				($13,307,489)	($7,694,069)	($2,433,716)	($2,586,044)	($575,060)	$0	$0	($18,599)	$0
51														
52		Taxes other than Income Tax				$25,801,669	$16,568,356	$3,900,035	$3,443,732	$1,018,427	$2,392	$27,729	$148,231	$0
53		Income Tax				$41,780,401	$27,255,660	$6,142,521	$5,242,983	$1,554,998	$7,283	$53,856	$231,973	$0
54														
55		Earned Return												
56			Rate Base			$1,469,170,309	$958,420,828	$215,996,237	$184,364,776	$54,680,115	$256,086	$1,893,798	$8,157,114	$0
57			Embedded Rate of Return			8.444%	8.444%	8.444%	8.444%	8.444%	8.444%	8.444%	8.444%	8.444%
58		Earned Return				$124,056,741	$80,929,055	$18,238,722	$15,567,762	$4,617,189	$21,624	$159,912	$688,787	$0
59														
60	**Cost of Service Margin**					**$321,572,227**	**$213,558,615**	**$46,011,044**	**$37,582,759**	**$11,430,446**	**$50,050**	**$534,336**	**$1,847,389**	**$0**
61														
62	**Margin to Cost Ratio (L26 / L60)**					**105.6%**	**93.7%**	**107.6%**	**125.3%**	**130.6%**	**552.5%**	**N/A**	**112.5%**	**0.0%**
63	**Revenue to Cost Ratio ((L26 + L13) / (L60 + L13))**						**97.3%**	**102.6%**			**128.8%**		**105.4%**	

	A	B	C	D	E	T	U	V	W	X	Y	AA	AB
1	BC Gas Utility Ltd. - Regional Studies												
2	2001 Cost of Service Study												
3	Distribution Mains Classified 75% Demand & 25% Customer												
4	"2001 Regional"												
5			(a)										
6	**Lower Mainland**					**Large Volume T-Srvc. Sched 22**	**Gen Firm T-Srvc. Bypass Schd 22**	**Sched 22A**	**T-Srvc Bypass Sch 22A**	**Sched 22B**	**BC Hydro**	**PCEC**	**Other Byron Creek**
7	REVENUES:												
8	Operating Revenues												
9		A. Sales Revenues				$0	$0	$0	$0	$0	$0	$0	$0
10		B. Transportation Revenues				$10,179,511	$0	$0	$0	$0	$4,421,000	$3,829,000	$0
11	Total Operating Revenues					$10,179,511	$0	$0	$0	$0	$4,421,000	$3,829,000	$0
12													
13	Less:	C. Cost of Gas				($6,600)	$0	$0	$0	$0	$0	$0	$0
14	Net Operating Revenues					$10,172,911	$0	$0	$0	$0	$4,421,000	$3,829,000	$0
15													
16	**Gross Margin**					**$10,172,911**	**$0**	**$0**	**$0**	**$0**	**$4,421,000**	**$3,829,000**	**$0**
17													
18	**Margin Reconciliation Adjustment (MRA)**					**($18,960)**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
19													
20	**SCP & FV incremental increase**												
21		SCP	$47,553,103		11.93%	$1,213,694	$0	$0	$0	$0	$0	$0	$0
22		FV	$5,016,968		1.25%	$127,438	$0	$0	$0	$0	$0	$0	$0
23		Total	$52,570,071			$1,341,132	$0	$0	$0	$0	$0	$0	$0
24	**Adjusted Gross Margin excl. MRA**					**$11,514,043**	**$0**	**$0**	**$0**	**$0**	**$4,421,000**	**$3,829,000**	**$0**
25													
26	**Adjusted Gross Margin incl. MRA**					**$11,495,083**	**$0**	**$0**	**$0**	**$0**	**$4,421,000**	**$3,829,000**	**$0**
27													
28	Cost of Service												
29		Operating and Maintenance											
30			Transmission			$0	$0	$0	$0	$0	$524,620	$324,011	$0
31			Storage			$0	$0	$0	$0	$0	$0	$0	$0
32			Transmission - SCP			$0	$0	$0	$0	$0	$0	$0	$0
33			Distribution			$14,037	$0	$0	$0	$0	$16,472	$14,951	$0
34			Customer Accounting			$24,048	$0	$0	$0	$0	$35,507	$32,227	$0
35			Gas Supply Administration			$17,236	$0	$0	$0	$0	$36,477	$29,470	$0
36			Marketing			$47,781	$0	$0	$0	$0	$199,597	$85,102	$0
37			O&M excluding General & Admin			$103,101	$0	$0	$0	$0	$812,673	$485,761	$0
38													
39			General & Admin			$48,139	$0	$0	$0	$0	$1,154,618	$726,777	$0
40		Total Operating and Maintenance				$151,241	$0	$0	$0	$0	$1,967,291	$1,212,538	$0
41													
42		Depreciation Expense				$37,530	$0	$0	$0	$0	$814,378	$513,508	$0
43		Other Amortization Expenses				$20,790	$0	$0	$0	$0	$9,024	$13,702	$0
44													
45	Other Revenues												
46		A. Late Payment Charge				$0	$0	$0	$0	$0	$0	$0	$0
47		B. Revenue from Service Work				$0	$0	$0	$0	$0	$0	$0	$0
48		C. SCP Revenue				$0	$0	$0	$0	$0	$0	$0	$0
49		D. Bypass Customer Revenue				$0	$0	$0	$0	$0	$0	$0	$0
50		Total Other Revenues				$0	$0	$0	$0	$0	$0	$0	$0
51													
52		Taxes other than Income Tax				$17,214	$0	$0	$0	$0	$414,602	$260,952	$0
53		Income Tax				$31,418	$0	$0	$0	$0	$773,020	$486,690	$0
54													
55		Earned Return											
56			Rate Base			$1,104,784	$0	$0	$0	$0	$27,182,546	$17,114,025	$0
57			Embedded Rate of Return			8.444%	8.444%	8.444%	8.444%	8.444%	8.444%	8.444%	8.444%
58		Earned Return				$93,288	$0	$0	$0	$0	$2,295,294	$1,445,108	$0
59													
60	**Cost of Service Margin**					**$351,481**	**$0**	**$0**	**$0**	**$0**	**$6,273,609**	**$3,932,498**	**$0**
61													
62	**Margin to Cost Ratio (L26 / L60)**					**N/A**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**70.5%**	**97.4%**	**0.0%**
63	**Revenue to Cost Ratio ((L26 + L13) / (L60 + L13))**												

	A	B	C	D	E	F	H	I	L	O	P	Q	R	S
1	BC Gas Utility Ltd. - Regional Studies													
2	2001 Cost of Service Study													
3	Distribution Mains Classified 75% Demand & 25% Customer													
4	"2001 Regional"													
5			(a)			(b)	(c)	(d)			(i)	(j)	(k)	
6	**Lower Mainland**					**TOTAL REGION**	**Residential Schd 1**	**Small Comm. Sales Schd 2**	**Sched 3 & 23**	**Sched 5 & 25**	**Seasonal Schd 4**	**Gen. Interr Sales / Trans Srvc. Schd 7,27**	**NGV Schd 6**	**Gen Firm T-Srvc. Bypass Schd 25**
66														
67	TOTAL OPERATIONS AND MAINTENANCE EXPENSES													
68		Demand				$46,743,826	$24,457,888	$8,028,602	$8,775,117	$2,550,878	$0	$0	$82,502	$0
69		Customer				$47,780,922	$39,998,595	$5,062,375	$1,239,359	$505,388	$12,541	$215,858	$347,758	$0
70		Delivery				$210,559	$64,302	$19,547	$24,480	$11,105	$291	$6,954	$697	$0
71														
72	TOTAL DEPRECIATION EXPENSES													
73		Demand				$26,394,599	$14,005,570	$4,597,500	$5,024,985	$1,460,735	$0	$0	$47,244	$0
74		Customer				$20,136,027	$16,632,742	$2,105,103	$515,367	$187,648	$5,215	$60,455	$522,645	$0
75		Delivery				$0	$0	$0	$0	$0	$0	$0	$0	$0
76														
77	TOT/	OTHER AMORTIZATION EXPENSES												
78		Demand				$1,356,552	$794,480	$260,798	$276,689	$76,280	$0	$0	$2,680	$0
79		Customer				$230,193	$382,703	$39,906	$9,770	$3,557	$99	$1,146	($207,978)	$0
80		Delivery				$388,227	$163,333	$49,651	$48,560	$19,301	$605	$8,425	$1,450	$0
81														
82	TOTAL TAXES OTHER THAN INCOME TAXES													
83		Demand				$16,687,241	$8,939,486	$2,934,496	$3,207,351	$932,359	$0	$0	$30,155	$0
84		Customer				$9,114,428	$7,628,870	$965,539	$236,381	$86,068	$2,392	$27,729	$118,076	$0
85		Delivery				$0	$0	$0	$0	$0	$0	$0	$0	$0
86														
87	TOTAL OTHER REVENUES													
88		Demand				($13,307,489)	($7,694,069)	($2,433,716)	($2,586,044)	($575,060)	$0	$0	($18,599)	$0
89		Customer				$0	$0	$0	$0	$0	$0	$0	$0	$0
90		Delivery				$0	$0	$0	$0	$0	$0	$0	$0	$0
91														
92	TOTAL RATE BASE													
93		Demand				$845,999,206	$447,959,873	$147,029,514	$160,661,003	$46,692,623	$2,603	$4,090	$1,516,123	$0
94		Customer				$577,977,350	$484,873,496	$61,172,005	$14,975,995	$5,453,568	$151,547	$1,757,695	$6,390,377	$0
95		Delivery				$45,193,754	$25,587,459	$7,794,719	$8,727,777	$2,533,924	$101,937	$132,013	$250,614	$0
96						$1,469,170,309	$958,420,828	$215,996,237	$184,364,776	$54,680,115	$256,086	$1,893,798	$8,157,114	$0
97	EARNED RETURN				0.08444									
98		Demand				$71,436,173	$37,825,732	$12,415,172	$13,566,215	$3,942,725	$220	$345	$128,021	$0
99		Customer				$48,804,407	$40,942,718	$5,165,364	$1,264,573	$460,499	$12,797	$148,420	$539,603	$0
100		Delivery				$3,816,161	$2,160,605	$658,186	$736,974	$213,965	$8,608	$11,147	$21,162	$0
101														
102	INCOME TAX													
103		Demand				$24,058,604	$12,739,124	$4,181,239	$4,568,893	$1,327,849	$74	$116	$43,116	
104		Customer				$16,436,573	$13,788,877	$1,739,615	$425,889	$155,089	$4,310	$49,986	$181,730	
105		Delivery				$1,285,224	$727,659	$221,667	$248,201	$72,060	$2,899	$3,754	$7,127	
106						$41,780,401	$27,255,660	$6,142,521	$5,242,983	$1,554,998	$7,283	$53,856	$231,973	$0
107	**Cost of Service Margin**													
108		Demand				$173,369,505	$91,068,211	$29,984,091	$32,833,205	$9,715,766	$294	$462	$315,119	$0
109		Customer				$142,502,551	$119,374,506	$15,077,902	$3,691,339	$1,398,250	$37,354	$503,593	$1,501,834	$0
110		Delivery				$5,700,171	$3,115,898	$949,051	$1,058,215	$316,430	$12,402	$30,281	$30,436	$0
111		Check total				$321,572,227	$213,558,615	$46,011,044	$37,582,759	$11,430,446	$50,050	$534,336	$1,847,389	$0
112														
113														
114	Peak Demand						510,293	167,510	166,902	49,404	479	-	1,721	$0
115														
116	Customers (unweighted) times 12						5,658,096	612,060	63,864	6,636	504	1,092	468	
117														
118	Throughput*99%						57,346,670	17,432,565	21,832,195	9,903,883	259,459	6,202,122	622,004	$0
119														
120														
121	**Unit Cost - Demand $ / GJ / Year**						**$178.46**	**$179.00**	**$196.72**	**$196.66**	**$0.61**	**N/A**	**$183.07**	**N/A**
122	**Unit Cost - Demand $ / Customer / Month**						**$16.10**	**$48.99**	**$514.11**					
123	**Unit Cost - Customer $ / Customer / Month**						**$21.10**	**$24.63**	**$57.80**	**$210.71**	**$74.11**	**$461.17**	**$3,209.05**	**N/A**
124	**Unit Cost - Delivery $ / GJ**						**$0.054**	**$0.054**	**$0.048**	**$0.032**	**$0.048**	**$0.005**	**$0.049**	**N/A**

	A	B	C	D	E	T	U	V	W	X	Y	AA	AB
1	BC Gas Utility Ltd. - Regional Studies												
2	2001 Cost of Service Study												
3	Distribution Mains Classified 75% Demand & 25% Customer												
4	"2001 Regional"												
5			(a)										
6	**Lower Mainland**					**Large Volume T-Srvc. Sched 22**	**Gen Firm T-Srvc. Bypass Schd 22**	**Sched 22A**	**T-Srvc Bypass Sch 22A**	**Sched 22B**	**BC Hydro**	**PCEC**	**Other Byron Creek**
66													
67	TOTAL OPERATIONS AND MAINTENANCE EXPENSES												
68		Demand				$0	$0	$0	$0	$0	$1,761,140	$1,087,699	$0
69		Customer				$134,004	$0	$0	$0	$0	$169,674	$95,369	$0
70		Delivery				$17,236	$0	$0	$0	$0	$36,477	$29,470	$0
71													
72	TOTAL DEPRECIATION EXPENSES												
73		Demand				$0	$0	$0	$0	$0	$778,039	$480,525	$0
74		Customer				$37,530	$0	$0	$0	$0	$36,339	$32,982	$0
75		Delivery				$0	$0	$0	$0	$0	$0	$0	$0
76													
77	TOT/	OTHER AMORTIZATION EXPENSES											
78		Demand				$0	$0	$0	$0	$0	($33,614)	($20,761)	$0
79		Customer				$711	$0	$0	$0	$0	$146	$132	$0
80		Delivery				$20,079	$0	$0	$0	$0	$42,492	$34,330	$0
81													
82	TOTAL TAXES OTHER THAN INCOME TAXES												
83		Demand				$0	$0	$0	$0	$0	$397,743	$245,650	$0
84		Customer				$17,214	$0	$0	$0	$0	$16,859	$15,301	$0
85		Delivery				$0	$0	$0	$0	$0	$0	$0	$0
86													
87	TOTAL OTHER REVENUES												
88		Demand				$0	$0	$0	$0	$0	$0	$0	$0
89		Customer				$0	$0	$0	$0	$0	$0	$0	$0
90		Delivery				$0	$0	$0	$0	$0	$0	$0	$0
91													
92	TOTAL RATE BASE												
93			Demand			$23	$0	$0	$0	$0	$26,046,654	$16,086,700	$0
94			Customer			$1,091,176	$0	$0	$0	$0	$1,107,281	$1,004,209	$0
95			Delivery			$13,584	$0	$0	$0	$0	$28,611	$23,116	$0
96						$1,104,784	$0	$0	$0	$0	$27,182,546	$17,114,025	$0
97	EARNED RETURN				0.08444								
98			Demand			$2	$0	$0	$0	$0	$2,199,379	$1,358,361	$0
99			Customer			$92,139	$0	$0	$0	$0	$93,499	$84,795	$0
100			Delivery			$1,147	$0	$0	$0	$0	$2,416	$1,952	$0
101													
102	INCOME TAX												
103			Demand			$1		$0		$0	$740,717	$457,475	$0
104			Customer			$31,031		$0		$0	$31,489	$28,558	$0
105			Delivery			$386		$0		$0	$814	$657	$0
106						$31,418	$0	$0	$0	$0	$773,020	$486,690	$0
107	**Cost of Service Margin**												
108			Demand			$3	$0	$0	$0	$0	$5,843,404	$3,608,951	$0
109			Customer			$312,630	$0	$0	$0	$0	$348,006	$257,138	$0
110			Delivery			$38,848	$0	$0	$0	$0	$82,199	$66,410	$0
111		Check total				$351,481	$0	$0	$0	$0	$6,273,609	$3,932,498	$0
112													
113													
114	Peak Demand					-	$0	-	$0	-			
115													
116	Customers (unweighted) times 12					432		-		-			
117													
118	Throughput*99%					15,372,004	$0	-	$0	-	$0	$0	$0
119													
120													
121	**Unit Cost - Demand $ / GJ / Year**					**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**
122	**Unit Cost - Demand $ / Customer / Month**												
123	**Unit Cost - Customer $ / Customer / Month**					**$723.68**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**
124	**Unit Cost - Delivery $ / GJ**					**$0.003**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**

	A	B	C	D	E	F	H	I	L	O	P	Q	R	S
1	BC Gas Utility Ltd. - Regional Studies													
2	2001 Cost of Service Study													
3	Distribution Mains Classified 75% Demand & 25% Customer													
4	"2001 Regional"													
5			(a)			(b)	(c)	(d)			(i)	(j)	(k)	
6	**Inland South**					**TOTAL REGION**	**Residential Schd 1**	**Small Comm. Sales Schd 2**	**Sched 3 & 23**	**Sched 5 & 25**	**Seasonal Schd 4**	**Gen. Interr Sales / Trans Srvc. Schd 7,27**	**NGV Schd 6**	**Gen Firm T-Srvc. Bypass Schd 25**
7	REVENUES:													
8	Operating Revenues													
9		A. Sales Revenues				$171,155,769	$111,268,853	$33,135,532	$17,525,619	$8,279,608	$623,188	$0	$322,970	$0
10		B. Transportation Revenues				$6,941,908	$0	$0	$114,764	$2,341,758	$0	$198,876	$0	$0
11	Total Operating Revenues					$178,097,677	$111,268,853	$33,135,532	$17,640,383	$10,621,366	$623,188	$198,876	$322,970	$0
12														
13	Less:	C. Cost of Gas				($108,385,146)	($66,860,226)	($22,005,590)	($12,451,013)	($6,351,710)	($493,919)	($5,018)	($176,750)	$0
14	Net Operating Revenues					$69,712,531	$44,408,626	$11,129,942	$5,189,369	$4,269,656	$129,269	$193,858	$146,220	$0
15														
16	**Gross Margin**					**$69,712,531**	**$44,408,626**	**$11,129,942**	**$5,189,369**	**$4,269,656**	**$129,269**	**$193,858**	**$146,220**	**$0**
17														
18	**Margin Reconciliation Adjustment (MRA)**					**($129,930)**	**($82,769)**	**($20,744)**	**($9,672)**	**($7,958)**	**($241)**	**($361)**	**($273)**	**$0**
19														
20	**SCP & FV incremental increase**													
21		SCP	$47,553,103		11.93%	$8,317,155	$5,298,236	$1,327,874	$619,125	$509,397	$15,423	$23,128	$17,445	$0
22		FV	$5,016,968		1.25%	$873,302	$556,315	$139,427	$65,008	$53,487	$1,619	$2,428	$1,832	$0
23		Total	$52,570,071			$9,190,457	$5,854,551	$1,467,301	$684,133	$562,884	$17,042	$25,557	$19,277	$0
24	**Adjusted Gross Margin excl. MRA**					**$78,902,988**	**$50,263,177**	**$12,597,243**	**$5,873,503**	**$4,832,540**	**$146,311**	**$219,415**	**$165,497**	**$0**
25														
26	**Adjusted Gross Margin incl. MRA**					**$78,773,058**	**$50,180,409**	**$12,576,499**	**$5,863,831**	**$4,824,582**	**$146,070**	**$219,053**	**$165,224**	**$0**
27														
28	Cost of Service													
29		Operating and Maintenance												
30			Transmission			$822,566	$435,713	$151,298	$82,820	$60,727	$0	$0	$438	$0
31			Storage			$132,225	$70,040	$24,321	$13,313	$9,762	$0	$0	$70	$0
32			Transmission - SCP			$280,079	$148,358	$51,516	$28,200	$20,677	$0	$0	$149	$0
33			Distribution			$3,079,896	$2,297,891	$406,492	$141,702	$99,609	$4,225	$718	$2,355	$0
34			Customer Accounting			$3,602,568	$3,091,363	$372,785	$59,412	$35,879	$7,563	$1,285	$1,101	$0
35			Gas Supply Administration			$55,136	$22,981	$7,410	$4,636	$5,628	$283	$379	$72	$0
36			Marketing			$872,701	$625,248	$99,690	$30,329	$33,031	$1,268	$2,248	$292	$0
37			O&M excluding General & Admin			$8,845,172	$6,691,592	$1,113,512	$360,411	$265,314	$13,339	$4,629	$4,478	$0
38														
39			General & Admin			$15,734,794	$10,102,042	$2,532,012	$1,184,554	$857,866	$10,534	$1,789	$48,156	$0
40		Total Operating and Maintenance				$24,579,966	$16,793,633	$3,645,523	$1,544,965	$1,123,180	$23,873	$6,418	$52,634	$0
41														
42		Depreciation Expense				$16,162,335	$10,266,132	$2,586,061	$1,213,535	$879,084	$10,565	$1,794	$95,015	$0
43		Other Amortization Expenses				$479,666	$299,940	$92,295	$48,967	$34,772	$559	$684	-$36,863	$0
44														
45	Other Revenues													
46		A. Late Payment Charge				($168,999)	($116,126)	($34,582)	($18,291)	$0	$0	$0	$0	$0
47		B. Revenue from Service Work				($802,350)	($551,328)	($164,184)	($86,838)	$0	$0	$0	$0	$0
48		C. SCP Revenue				($2,503,796)	($1,326,259)	($460,532)	($252,093)	($184,846)	$0	$0	($1,332)	$0
49		D. Bypass Customer Revenue				$0	$0	$0	$0	$0	$0	$0	$0	$0
50		Total Other Revenues				($3,475,144)	($1,993,713)	($659,298)	($357,222)	($184,846)	$0	$0	($1,332)	$0
51														
52		Taxes other than Income Tax				$6,528,422	$4,094,090	$1,070,265	$513,319	$372,535	$3,793	$644	$17,798	$0
53		Income Tax				$13,481,947	$8,685,592	$2,166,584	$1,017,545	$727,840	$11,084	$3,946	$36,167	$0
54														
55		Earned Return												
56			Rate Base			$474,080,550	$305,421,058	$76,185,987	$35,781,039	$25,593,841	$389,768	$138,757	$1,271,797	$0
57			Embedded Rate of Return			8.444%	8.444%	8.444%	8.444%	8.444%	8.444%	8.444%	8.444%	8.444%
58		Earned Return				$40,031,362	$25,789,754	$6,433,145	$3,021,351	$2,161,144	$32,912	$11,717	$107,391	$0
59														
60	**Cost of Service Margin**					**$97,788,553**	**$63,935,430**	**$15,334,575**	**$7,002,460**	**$5,113,709**	**$82,786**	**$25,203**	**$270,809**	**$0**
61														
62	**Margin to Cost Ratio (L26 / L60)**					**80.6%**	**78.5%**	**82.0%**	**83.7%**	**94.3%**	**176.4%**	**N/A**	**61.0%**	**0.0%**
63	**Revenue to Cost Ratio ((L26 + L13) / (L60 + L13))**						**89.5%**	**92.6%**			**111.0%**		**76.4%**	

	A	B	C	D	E	T	U	V	W	X	Y	AA	AB
1	BC Gas Utility Ltd. - Regional Studies												
2	2001 Cost of Service Study												
3	Distribution Mains Classified 75% Demand & 25% Customer												
4	"2001 Regional"												
5			(a)										
6	**Inland South**					**Large Volume T-Srvc. Sched 22**	**Gen Firm T-Srvc. Bypass Schd 22**	**Sched 22A**	**T-Srvc Bypass Sch 22A**	**Sched 22B**	**BC Hydro**	**PCEC**	**Other Byron Creek**
7	REVENUES:												
8	Operating Revenues												
9		A. Sales Revenues				$0	$0	$0	$0	$0	$0	$0	$0
10		B. Transportation Revenues				$0	$0	$4,286,511	$0	$0	$0	$0	$0
11	Total Operating Revenues					$0	$0	$4,286,511	$0	$0	$0	$0	$0
12													
13	Less:	C. Cost of Gas				$0	$0	($40,920)	$0	$0	$0	$0	$0
14	Net Operating Revenues					$0	$0	$4,245,591	$0	$0	$0	$0	$0
15													
16	**Gross Margin**					**$0**	**$0**	**$4,245,591**	**$0**	**$0**	**$0**	**$0**	**$0**
17													
18	**Margin Reconciliation Adjustment (MRA)**					**$0**	**$0**	**($7,913)**	**$0**	**$0**	**$0**	**$0**	**$0**
19													
20	**SCP & FV incremental increase**												
21		SCP	$47,553,103		11.93%	$0	$0	$506,526	$0	$0	$0	$0	$0
22		FV	$5,016,968		1.25%	$0	$0	$53,185	$0	$0	$0	$0	$0
23		Total	$52,570,071			$0	$0	$559,712	$0	$0	$0	$0	$0
24	**Adjusted Gross Margin excl. MRA**					**$0**	**$0**	**$4,805,303**	**$0**	**$0**	**$0**	**$0**	**$0**
25													
26	**Adjusted Gross Margin incl. MRA**					**$0**	**$0**	**$4,797,390**	**$0**	**$0**	**$0**	**$0**	**$0**
27													
28	Cost of Service												
29		Operating and Maintenance											
30			Transmission			$0	$0	$91,571	$0	$0	$0	$0	$0
31			Storage			$0	$0	$14,720	$0	$0	$0	$0	$0
32			Transmission - SCP			$0	$0	$31,180	$0	$0	$0	$0	$0
33			Distribution			$0	$0	$126,904	$0	$0	$0	$0	$0
34			Customer Accounting			$0	$0	$33,181	$0	$0	$0	$0	$0
35			Gas Supply Administration			$0	$0	$13,747	$0	$0	$0	$0	$0
36			Marketing			$0	$0	$80,596	$0	$0	$0	$0	$0
37			O&M excluding General & Admin			$0	$0	$391,898	$0	$0	$0	$0	$0
38													
39			General & Admin			$0	$0	$997,842	$0	$0	$0	$0	$0
40		Total Operating and Maintenance				$0	$0	$1,389,740	$0	$0	$0	$0	$0
41													
42		Depreciation Expense				$0	$0	$1,110,148	$0	$0	$0	$0	$0
43		Other Amortization Expenses				$0	$0	$39,311	$0	$0	$0	$0	$0
44													
45	Other Revenues												
46		A. Late Payment Charge				$0	$0	$0	$0	$0	$0	$0	$0
47		B. Revenue from Service Work				$0	$0	$0	$0	$0	$0	$0	$0
48		C. SCP Revenue				$0	$0	($278,733)	$0	$0	$0	$0	$0
49		D. Bypass Customer Revenue				$0	$0	$0	$0	$0	$0	$0	$0
50		Total Other Revenues				$0	$0	($278,733)	$0	$0	$0	$0	$0
51													
52		Taxes other than Income Tax				$0	$0	$455,978	$0	$0	$0	$0	$0
53		Income Tax				$0	$0	$833,188	$0	$0	$0	$0	$0
54													
55		Earned Return											
56			Rate Base			$0	$0	$29,298,304	$0	$0	$0	$0	$0
57			Embedded Rate of Return			8.444%	8.444%	8.444%	8.444%	8.444%	8.444%	8.444%	8.444%
58		Earned Return				$0	$0	$2,473,949	$0	$0	$0	$0	$0
59													
60	**Cost of Service Margin**					**$0**	**$0**	**$6,023,581**	**$0**	**$0**	**$0**	**$0**	**$0**
61													
62	**Margin to Cost Ratio (L26 / L60)**					**N/A**	**0.0%**	**79.6%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**
63	**Revenue to Cost Ratio ((L26 + L13) / (L60 + L13))**												

	A	B	C	D	E	F	H	I	L	O	P	Q	R	S
1	BC Gas Utility Ltd. - Regional Studies													
2	2001 Cost of Service Study													
3	Distribution Mains Classified 75% Demand & 25% Customer													
4	"2001 Regional"													
5			(a)			(b)	(c)	(d)			(i)	(j)	(k)	
6	**Inland South**					**TOTAL REGION**	**Residential Schd 1**	**Small Comm. Sales Schd 2**	**Sched 3 & 23**	**Sched 5 & 25**	**Seasonal Schd 4**	**Gen. Interr Sales / Trans Srvc. Schd 7,27**	**NGV Schd 6**	**Gen Firm T-Srvc. Bypass Schd 25**
64														
66														
67	TOTAL OPERATIONS AND MAINTENANCE EXPENSES													
68		Demand				$13,030,163	$7,129,557	$2,475,680	$1,355,176	$993,676	$0	$0	$7,162	$0
69		Customer				$11,496,168	$9,641,891	$1,162,710	$185,304	$123,986	$23,590	$6,039	$45,400	$0
70		Delivery				$53,635	$22,185	$7,134	$4,485	$5,517	$283	$379	$72	$0
71														
72	TOTAL DEPRECIATION EXPENSES													
73		Demand				$10,953,612	$5,947,762	$2,065,311	$1,130,542	$828,964	$0	$0	$5,975	$0
74		Customer				$5,208,724	$4,318,370	$520,750	$82,993	$50,120	$10,565	$1,794	$89,040	$0
75		Delivery				$0	$0	$0	$0	$0	$0	$0	$0	$0
76														
77	TOT/	OTHER AMORTIZATION EXPENSES												
78		Demand				$378,909	$214,835	$74,600	$40,604	$26,587	$0	$0	$216	$0
79		Customer				$6,346	$38,540	$2,722	$434	$262	$55	$9	($37,207)	$0
80		Delivery				$94,411	$46,565	$14,973	$7,930	$7,923	$504	$675	$128	$0
81														
82	TOTAL TAXES OTHER THAN INCOME TAXES													
83		Demand				$4,691,651	$2,543,813	$883,318	$483,524	$354,542	$0	$0	$2,556	$0
84		Customer				$1,836,771	$1,550,277	$186,947	$29,794	$17,993	$3,793	$644	$15,243	$0
85		Delivery				$0	$0	$0	$0	$0	$0	$0	$0	$0
86														
87	TOTAL OTHER REVENUES													
88		Demand				($3,475,144)	($1,993,713)	($659,298)	($357,222)	($184,846)	$0	$0	($1,332)	$0
89		Customer				$0	$0	$0	$0	$0	$0	$0	$0	$0
90		Delivery				$0	$0	$0	$0	$0	$0	$0	$0	$0
91														
92	TOTAL RATE BASE													
93		Demand				$309,658,501	$168,450,838	$58,488,303	$32,017,273	$23,457,185	$1,983	$20	$169,665	$0
94		Customer				$154,322,568	$130,890,829	$15,737,170	$2,508,071	$1,514,819	$319,289	$54,256	$1,084,193	$0
95		Delivery				$10,099,481	$6,079,391	$1,960,513	$1,255,695	$621,837	$68,496	$84,480	$17,939	$0
96						$474,080,550	$305,421,058	$76,185,987	$35,781,039	$25,593,841	$389,768	$138,757	$1,271,797	$0
97	EARNED RETURN				0.08444									
98		Demand				$26,147,564	$14,223,989	$4,938,752	$2,703,539	$1,980,725	$167	$2	$14,327	$0
99		Customer				$13,030,998	$11,052,422	$1,328,847	$211,781	$127,911	$26,961	$4,581	$91,549	$0
100		Delivery				$852,800	$513,344	$165,546	$106,031	$52,508	$5,784	$7,134	$1,515	$0
101														
102	INCOME TAX													
103		Demand				$8,806,097	$4,790,421	$1,663,296	$910,510	$667,078	$56	$1	$4,825	
104		Customer				$4,388,640	$3,722,286	$447,535	$71,325	$43,079	$9,080	$1,543	$30,832	
105		Delivery				$287,210	$172,886	$55,753	$35,710	$17,684	$1,948	$2,402	$510	
106						$13,481,947	$8,685,592	$2,166,584	$1,017,545	$727,840	$11,084	$3,946	$36,167	$0
107	**Cost of Service Margin**													
108		Demand				$60,532,851	$32,856,664	$11,441,659	$6,266,674	$4,666,725	$224	$2	$33,728	$0
109		Customer				$35,967,646	$30,323,786	$3,649,510	$581,631	$363,351	$74,044	$14,611	$234,857	$0
110		Delivery				$1,288,056	$754,980	$243,406	$154,155	$83,633	$8,518	$10,590	$2,224	$0
111		Check total				$97,788,553	$63,935,430	$15,334,575	$7,002,460	$5,113,709	$82,786	$25,203	$270,809	$0
112														
113														
114	Peak Demand						120,919	41,988	21,002	15,963	319	-	121	$0
115														
116	Customers (unweighted) times 12						1,632,293	165,409	8,023	1,068	156	36	78	
117														
118	Throughput*99%						13,588,909	4,369,670	2,747,246	3,379,534	173,125	231,951	43,895	$0
119														
120														
121	**Unit Cost - Demand $ / GJ / Year**						**$271.72**	**$272.50**	**$298.38**	**$292.34**	**$0.70**	**N/A**	**$277.65**	**N/A**
122	**Unit Cost - Demand $ / Customer / Month**						**$20.13**	**$69.17**	**$781.08**					
123	**Unit Cost - Customer $ / Customer / Month**						**$18.58**	**$22.06**	**$72.49**	**$340.22**	**$474.64**	**$405.87**	**$3,010.99**	**N/A**
124	**Unit Cost - Delivery $ / GJ**						**$0.056**	**$0.056**	**$0.056**	**$0.025**	**$0.049**	**$0.046**	**$0.051**	**N/A**

	A	B	C	D	E	T	U	V	W	X	Y	AA	AB
1	BC Gas Utility Ltd. - Regional Studies												
2	2001 Cost of Service Study												
3	Distribution Mains Classified 75% Demand & 25% Customer												
4	"2001 Regional"												
5			(a)										
6	**Inland South**					**Large Volume T-Srvc. Sched 22**	**Gen Firm T-Srvc. Bypass Schd 22**	**Sched 22A**	**T-Srvc Bypass Sch 22A**	**Sched 22B**	**BC Hydro**	**PCEC**	**Other Byron Creek**
64													
66													
67	TOTAL OPERATIONS AND MAINTENANCE EXPENSES												
68		Demand				$0	$0	$1,068,912	$0	$0	$0	$0	$0
69		Customer				$0	$0	$307,248	$0	$0	$0	$0	$0
70		Delivery				$0	$0	$13,580	$0	$0	$0	$0	$0
71													
72	TOTAL DEPRECIATION EXPENSES												
73		Demand				$0	$0	$975,056	$0	$0	$0	$0	$0
74		Customer				$0	$0	$135,092	$0	$0	$0	$0	$0
75		Delivery				$0	$0	$0	$0	$0	$0	$0	$0
76													
77	TOT	OTHER AMORTIZATION EXPENSES											
78		Demand				$0	$0	$22,067	$0	$0	$0	$0	$0
79		Customer				$0	$0	$1,530	$0	$0	$0	$0	$0
80		Delivery				$0	$0	$15,714	$0	$0	$0	$0	$0
81													
82	TOTAL TAXES OTHER THAN INCOME TAXES												
83		Demand				$0	$0	$423,898	$0	$0	$0	$0	$0
84		Customer				$0	$0	$32,080	$0	$0	$0	$0	$0
85		Delivery				$0	$0	$0	$0	$0	$0	$0	$0
86													
87	TOTAL OTHER REVENUES												
88		Demand				$0	$0	($278,733)	$0	$0	$0	$0	$0
89		Customer				$0	$0	$0	$0	$0	$0	$0	$0
90		Delivery				$0	$0	$0	$0	$0	$0	$0	$0
91													
92	TOTAL RATE BASE												
93		Demand				$0	$0	$27,073,232	$0	$0	$0	$0	$0
94		Customer				$0	$0	$2,213,941	$0	$0	$0	$0	$0
95		Delivery				$0	$0	$11,130	$0	$0	$0	$0	$0
96						$0	$0	$29,298,304	$0	$0	$0	$0	$0
97	EARNED RETURN				0.08444								
98		Demand				$0	$0	$2,286,064	$0	$0	$0	$0	$0
99		Customer				$0	$0	$186,945	$0	$0	$0	$0	$0
100		Delivery				$0	$0	$940	$0	$0	$0	$0	$0
101													
102	INCOME TAX												
103		Demand				$0		$769,911		$0	$0	$0	$0
104		Customer				$0		$62,960		$0	$0	$0	$0
105		Delivery				$0		$317		$0	$0	$0	$0
106						$0	$0	$833,188	$0	$0	$0	$0	$0
107	**Cost of Service Margin**												
108		Demand				$0	$0	$5,267,176	$0	$0	$0	$0	$0
109		Customer				$0	$0	$725,855	$0	$0	$0	$0	$0
110		Delivery				$0	$0	$30,550	$0	$0	$0	$0	$0
111		Check total				$0	$0	$6,023,581	$0	$0	$0	$0	$0
112													
113													
114	Peak Demand					-	$0	26,473	$0	-			
115													
116	Customers (unweighted) times 12					-		84		-			
117													
118	Throughput*99%					-	$0	8,317,840	$0	-	$0	$0	$0
119													
120													
121	**Unit Cost - Demand $ / GJ / Year**					**N/A**	**N/A**	**$198.96**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**
122	**Unit Cost - Demand $ / Customer / Month**												
123	**Unit Cost - Customer $ / Customer / Month**					**N/A**	**N/A**	**$8,641.13**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**
124	**Unit Cost - Delivery $ / GJ**					**N/A**	**N/A**	**$0.004**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**

	A	B	C	D	E	F	H	I	L	O	P	Q	R	S
1	BC Gas Utility Ltd. - Regional Studies													
2	2001 Cost of Service Study													
3	Distribution Mains Classified 75% Demand & 25% Customer													
4	"2001 Regional"													
5			(a)			(b)	(c)	(d)			(i)	(j)	(k)	
6	**Inland North**					**TOTAL REGION**	**Residential Schd 1**	**Small Comm. Sales Schd 2**	**Sched 3 & 23**	**Sched 5 & 25**	**Seasonal Schd 4**	**Gen. Interr Sales / Trans Srvc. Schd 7,27**	**NGV Schd 6**	**Gen Firm T-Srvc. Bypass Schd 25**
7	REVENUES:													
8	Operating Revenues													
9		A. Sales Revenues				$68,203,079	$42,994,247	$12,706,568	$8,724,381	$3,241,969	$143,813	$51,301	$340,800	$0
10		B. Transportation Revenues				$3,610,813	$0	$0	$95,636	$542,313	$0	$0	$0	$708,000
11	Total Operating Revenues					$71,813,893	$42,994,247	$12,706,568	$8,820,017	$3,784,282	$143,813	$51,301	$340,800	$708,000
12														
13	Less:	C. Cost of Gas				($43,316,030)	($25,840,474)	($8,417,710)	($6,173,687)	($2,465,282)	($113,981)	($38,548)	($176,750)	($8,000)
14	Net Operating Revenues					$28,497,863	$17,153,774	$4,288,858	$2,646,330	$1,319,000	$29,831	$12,753	$164,050	$700,000
15														
16	**Gross Margin**					**$28,497,863**	**$17,153,774**	**$4,288,858**	**$2,646,330**	**$1,319,000**	**$29,831**	**$12,753**	**$164,050**	**$700,000**
17														
18	**Margin Reconciliation Adjustment (MRA)**					**($48,823)**	**($31,971)**	**($7,994)**	**($4,932)**	**($2,458)**	**($56)**	**($24)**	**($306)**	**$0**
19														
20	**SCP & FV incremental increase**													
21		SCP	$47,553,103		11.93%	$3,125,276	$2,046,556	$511,688	$315,724	$157,365	$3,559	$1,522	$19,572	$0
22		FV	$5,016,968		1.25%	$328,154	$214,889	$53,727	$33,151	$16,523	$374	$160	$2,055	$0
23		Total	$52,570,071			$3,453,430	$2,261,445	$565,416	$348,875	$173,889	$3,933	$1,681	$21,627	$0
24	**Adjusted Gross Margin excl. MRA**					**$31,951,293**	**$19,415,218**	**$4,854,274**	**$2,995,206**	**$1,492,888**	**$33,764**	**$14,434**	**$185,677**	**$700,000**
25														
26	**Adjusted Gross Margin incl. MRA**					**$31,902,470**	**$19,383,247**	**$4,846,280**	**$2,990,274**	**$1,490,430**	**$33,708**	**$14,411**	**$185,372**	**$700,000**
27														
28	Cost of Service													
29		Operating and Maintenance												
30			Transmission			$279,925	$99,268	$34,145	$24,843	$11,475	$0	$0	$258	$10,815
31			Storage			$52,126	$30,440	$10,470	$7,618	$3,519	$0	$0	$79	$0
32			Transmission - SCP			$0	$0	$0	$0	$0	$0	$0	$0	$0
33			Distribution			$1,213,982	$809,434	$146,193	$70,126	$32,869	$864	$341	$2,123	$25,289
34			Customer Accounting			$1,403,490	$1,153,332	$138,400	$29,900	$14,745	$1,687	$666	$1,064	$2,780
35			Gas Supply Administration			$17,854	$3,701	$1,188	$973	$691	$26	$8	$29	$940
36			Marketing			$347,346	$217,890	$31,658	$11,169	$7,388	$283	$533	$242	$4,904
37			O&M excluding General & Admin			$3,314,723	$2,314,065	$362,054	$144,629	$70,686	$2,859	$1,548	$3,795	$44,728
38														
39			General & Admin			$5,473,918	$3,160,195	$686,430	$389,639	$181,420	$2,616	$1,033	$50,049	$149,476
40		Total Operating and Maintenance				$8,788,641	$5,474,260	$1,048,484	$534,268	$252,105	$5,475	$2,581	$53,844	$194,204
41														
42		Depreciation Expense				$3,827,086	$2,327,899	$471,551	$252,870	$117,989	$2,150	$849	$86,849	$91,712
43		Other Amortization Expenses				$146,471	$92,195	$25,916	$17,361	$7,589	$94	$30	-$29,402	$5,131
44														
45	Other Revenues													
46		A. Late Payment Charge				($65,669)	($43,824)	($12,952)	($8,893)	$0	$0	$0	$0	$0
47		B. Revenue from Service Work				($311,774)	($208,063)	($61,491)	($42,220)	$0	$0	$0	$0	$0
48		C. SCP Revenue				$0	$0	$0	$0	$0	$0	$0	$0	$0
49		D. Bypass Customer Revenue				$0	$0	$0	$0	$0	$0	$0	$0	$0
50		Total Other Revenues				($377,444)	($251,888)	($74,443)	($51,113)	$0	$0	$0	$0	$0
51														
52		Taxes other than Income Tax				$1,934,542	$1,117,799	$242,461	$137,481	$64,015	$928	$366	$17,738	$52,715
53		Income Tax				$3,900,722	$2,266,523	$491,263	$280,619	$129,563	$2,323	$873	$32,522	$100,350
54														
55		Earned Return												
56			Rate Base			$137,165,390	$79,700,247	$17,274,834	$9,867,718	$4,555,972	$81,675	$30,715	$1,143,612	$3,528,709
57			Embedded Rate of Return			8.444%	8.444%	8.444%	8.444%	8.444%	8.444%	8.444%	8.444%	8.444%
58		Earned Return				$11,582,246	$6,729,889	$1,458,687	$833,230	$384,706	$6,897	$2,594	$96,567	$297,964
59														
60	**Cost of Service Margin**					**$29,802,264**	**$17,756,678**	**$3,663,919**	**$2,004,716**	**$955,967**	**$17,865**	**$7,294**	**$258,118**	**$742,076**
61														
62	**Margin to Cost Ratio (L26 / L60)**					**107.0%**	**109.2%**	**132.3%**	**149.2%**	**155.9%**	**188.7%**	**N/A**	**71.8%**	**94.3%**
63	**Revenue to Cost Ratio ((L26 + L13) / (L60 + L13))**						**103.7%**	**109.8%**			**112.0%**		**83.3%**	

	A	B	C	D	E	T	U	V	W	X	Y	AA	AB
1	BC Gas Utility Ltd. - Regional Studies												
2	2001 Cost of Service Study												
3	Distribution Mains Classified 75% Demand & 25% Customer												
4	"2001 Regional"												
5			(a)										
6	**Inland North**					**Large Volume T-Srvc. Sched 22**	**Gen Firm T-Srvc. Bypass Schd 22**	**Sched 22A**	**T-Srvc Bypass Sch 22A**	**Sched 22B**	**BC Hydro**	**PCEC**	**Other Byron Creek**
7	REVENUES:												
8	Operating Revenues												
9		A. Sales Revenues				$0	$0	$0	$0	$0	$0	$0	$0
10		B. Transportation Revenues				$0	$140,000	$586,364	$1,538,500	$0	$0	$0	$0
11	Total Operating Revenues					$0	$140,000	$586,364	$1,538,500	$0	$0	$0	$0
12													
13	Less:	C. Cost of Gas				$0	($5,000)	($5,598)	($71,000)	$0	$0	$0	$0
14	Net Operating Revenues					$0	$135,000	$580,766	$1,467,500	$0	$0	$0	$0
15													
16	**Gross Margin**					**$0**	**$135,000**	**$580,766**	**$1,467,500**	**$0**	**$0**	**$0**	**$0**
17													
18	**Margin Reconciliation Adjustment (MRA)**					**$0**	**$0**	**($1,082)**	**$0**	**$0**	**$0**	**$0**	**$0**
19													
20	**SCP & FV incremental increase**												
21		SCP	$47,553,103		11.93%	$0	$0	$69,289	$0	$0	$0	$0	$0
22		FV	$5,016,968		1.25%	$0	$0	$7,275	$0	$0	$0	$0	$0
23		Total	$52,570,071			$0	$0	$76,565	$0	$0	$0	$0	$0
24	**Adjusted Gross Margin excl. MRA**					**$0**	**$135,000**	**$657,331**	**$1,467,500**	**$0**	**$0**	**$0**	**$0**
25													
26	**Adjusted Gross Margin incl. MRA**					**$0**	**$135,000**	**$656,248**	**$1,467,500**	**$0**	**$0**	**$0**	**$0**
27													
28	Cost of Service												
29		Operating and Maintenance											
30			Transmission			$0	$10,612	$8,706	$79,804	$0	$0	$0	$0
31			Storage			$0	$0	$0	$0	$0	$0	$0	$0
32			Transmission - SCP			$0	$0	$0	$0	$0	$0	$0	$0
33			Distribution			$0	$8,205	$28,596	$89,944	$0	$0	$0	$0
34			Customer Accounting			$0	$3,943	$13,744	$43,229	$0	$0	$0	$0
35			Gas Supply Administration			$0	$181	$726	$9,392	$0	$0	$0	$0
36			Marketing			$0	$5,784	$13,148	$54,348	$0	$0	$0	$0
37			O&M excluding General & Admin			$0	$28,725	$64,919	$276,716	$0	$0	$0	$0
38													
39			General & Admin			$0	$86,122	$91,873	$675,065	$0	$0	$0	$0
40		Total Operating and Maintenance				$0	$114,847	$156,792	$951,781	$0	$0	$0	$0
41													
42		Depreciation Expense				$0	$44,850	$61,357	$369,010	$0	$0	$0	$0
43		Other Amortization Expenses				$0	$1,763	$2,418	$23,377	$0	$0	$0	$0
44													
45	Other Revenues												
46		A. Late Payment Charge				$0	$0	$0	$0	$0	$0	$0	$0
47		B. Revenue from Service Work				$0	$0	$0	$0	$0	$0	$0	$0
48		C. SCP Revenue				$0	$0	$0	$0	$0	$0	$0	$0
49		D. Bypass Customer Revenue				$0	$0	$0	$0	$0	$0	$0	$0
50		Total Other Revenues				$0	$0	$0	$0	$0	$0	$0	$0
51													
52		Taxes other than Income Tax				$0	$30,383	$32,449	$238,205	$0	$0	$0	$0
53		Income Tax				$0	$60,562	$63,138	$472,986	$0	$0	$0	$0
54													
55		Earned Return											
56			Rate Base			$0	$2,129,593	$2,220,175	$16,632,141	$0	$0	$0	$0
57			Embedded Rate of Return			8.444%	8.444%	8.444%	8.444%	8.444%	8.444%	8.444%	8.444%
58		Earned Return				$0	$179,823	$187,472	$1,404,418	$0	$0	$0	$0
59													
60	**Cost of Service Margin**					**$0**	**$432,228**	**$503,625**	**$3,459,777**	**$0**	**$0**	**$0**	**$0**
61													
62	**Margin to Cost Ratio (L26 / L60)**					**N/A**	**31.2%**	**130.3%**	**42.4%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**
63	**Revenue to Cost Ratio ((L26 + L13) / (L60 + L13))**												

	A B C D	E	F	H	I	L	O	P	Q	R	S
1	BC Gas Utility Ltd. - Regional Studies										
2	2001 Cost of Service Study										
3	Distribution Mains Classified 75% Demand & 25% Customer										
4	"2001 Regional"										
5	(a)		(b)	(c)	(d)			(i)	(j)	(k)	
6	**Inland North**		**TOTAL REGION**	**Residential Schd 1**	**Small Comm. Sales Schd 2**	**Sched 3 & 23**	**Sched 5 & 25**	**Seasonal Schd 4**	**Gen. Interr Sales / Trans Srvc. Schd 7,27**	**NGV Schd 6**	**Gen Firm T-Srvc. Bypass Schd 25**
64											
67	TOTAL OPERATIONS AND MAINTENANCE EXPENSES										
68	Demand		$4,025,086	$1,745,368	$600,350	$436,797	$201,753	$0	$0	$4,533	$182,527
69	Customer		$4,746,293	$3,725,537	$447,064	$96,584	$49,701	$5,449	$2,574	$49,283	$10,737
70	Delivery		$17,262	$3,355	$1,069	$887	$651	$26	$8	$28	$940
71											
72	TOTAL DEPRECIATION EXPENSES										
73	Demand		$1,890,561	$858,174	$295,184	$214,767	$99,199	$0	$0	$2,229	$88,169
74	Customer		$1,936,525	$1,469,725	$176,367	$38,102	$18,790	$2,150	$849	$84,620	$3,543
75	Delivery		$0	$0	$0	$0	$0	$0	$0	$0	$0
76											
77	TOT/ OTHER AMORTIZATION EXPENSES										
78	Demand		$117,081	$58,782	$20,219	$14,514	$6,000	$0	$0	$153	$3,950
79	Customer		($4,452)	$21,178	$1,800	$389	$192	$22	$9	($29,634)	$36
80	Delivery		$33,842	$12,235	$3,897	$2,458	$1,397	$72	$21	$79	$1,145
81											
82	TOTAL TAXES OTHER THAN INCOME TAXES										
83	Demand		$1,136,848	$483,662	$166,364	$121,042	$55,908	$0	$0	$1,256	$51,187
84	Customer		$797,693	$634,137	$76,096	$16,440	$8,107	$928	$366	$16,482	$1,528
85	Delivery		$0	$0	$0	$0	$0	$0	$0	$0	$0
86											
87	TOTAL OTHER REVENUES										
88	Demand		($377,444)	($251,888)	($74,443)	($51,113)	$0	$0	$0	$0	$0
89	Customer		$0	$0	$0	$0	$0	$0	$0	$0	$0
90	Delivery		$0	$0	$0	$0	$0	$0	$0	$0	$0
91											
92	TOTAL RATE BASE										
93	Demand		$77,168,854	$32,422,845	$11,150,762	$8,112,632	$3,743,994	$401	$135	$84,593	$3,419,922
94	Customer		$56,017,385	$44,929,358	$5,374,336	$1,161,071	$572,593	$65,506	$25,884	$1,041,194	$107,972
95	Delivery		$3,979,151	$2,348,044	$749,736	$594,014	$239,385	$15,768	$4,695	$17,824	$815
96			$137,165,390	$79,700,247	$17,274,834	$9,867,718	$4,555,972	$81,675	$30,715	$1,143,612	$3,528,709
97	EARNED RETURN	0.08444									
98	Demand		$6,516,138	$2,737,785	$941,570	$685,031	$316,143	$34	$11	$7,143	$288,778
99	Customer		$4,730,108	$3,793,835	$453,809	$98,041	$48,350	$5,531	$2,186	$87,918	$9,117
100	Delivery		$336,000	$198,269	$63,308	$50,159	$20,214	$1,331	$396	$1,505	$69
101											
102	INCOME TAX										
103	Demand		$2,194,535	$922,044	$317,106	$230,708	$106,472	$11	$4	$2,406	$97,256
104	Customer		$1,593,028	$1,277,705	$152,836	$33,019	$16,283	$1,863	$736	$29,610	$3,071
105	Delivery		$113,159	$66,774	$21,321	$16,893	$6,808	$448	$134	$507	$23
106			$3,900,722	$2,266,523	$491,263	$280,619	$129,563	$2,323	$873	$32,522	$100,350
107	**Cost of Service Margin**										
108	Demand		$15,502,806	$6,553,928	$2,266,352	$1,651,745	$785,475	$45	$15	$17,719	$711,868
109	Customer		$13,799,195	$10,922,118	$1,307,973	$282,574	$141,423	$15,943	$6,720	$238,280	$28,031
110	Delivery		$500,263	$280,632	$89,594	$70,396	$29,069	$1,878	$559	$2,119	$2,177
111	Check total		$29,802,264	$17,756,678	$3,663,919	$2,004,716	$955,967	$17,865	$7,294	$258,118	$742,076
112											
113											
114	Peak Demand			46,772	16,088	10,621	5,010	74	-	121	$0
115											
116	Customers (unweighted) times 12			630,091	63,539	4,049	432	36	12	78	
117											
118	Throughput*99%			5,256,231	1,674,266	1,389,309	1,019,886	39,952	11,775	43,895	$0
119											
120											
121	**Unit Cost - Demand $ / GJ / Year**			**$140.13**	**$140.87**	**$155.52**	**$156.78**	**$0.61**	**N/A**	**$145.87**	**N/A**
122	**Unit Cost - Demand $ / Customer / Month**			**$10.40**	**$35.67**	**$407.94**					
123	**Unit Cost - Customer $ / Customer / Month**			**$17.33**	**$20.59**	**$69.79**	**$327.37**	**$442.85**	**$559.99**	**$3,054.87**	**N/A**
124	**Unit Cost - Delivery $ / GJ**			**$0.053**	**$0.054**	**$0.051**	**$0.029**	**$0.047**	**$0.047**	**$0.048**	**N/A**

	A	B	C	D	E	T	U	V	W	X	Y	AA	AB
1	BC Gas Utility Ltd. - Regional Studies												
2	2001 Cost of Service Study												
3	Distribution Mains Classified 75% Demand & 25% Customer												
4	"2001 Regional"												
5			(a)										
6	**Inland North**					**Large Volume T-Srvc. Sched 22**	**Gen Firm T-Srvc. Bypass Schd 22**	**Sched 22A**	**T-Srvc Bypass Sch 22A**	**Sched 22B**	**BC Hydro**	**PCEC**	**Other Byron Creek**
64													
67	TOTAL OPERATIONS AND MAINTENANCE EXPENSES												
68		Demand				$0	$91,403	$74,987	$687,368	$0	$0	$0	$0
69		Customer				$0	$23,263	$81,079	$255,022	$0	$0	$0	$0
70		Delivery				$0	$181	$726	$9,392	$0	$0	$0	$0
71													
72	TOTAL DEPRECIATION EXPENSES												
73		Demand				$0	$35,633	$29,234	$267,971	$0	$0	$0	$0
74		Customer				$0	$9,217	$32,123	$101,039	$0	$0	$0	$0
75		Delivery				$0	$0	$0	$0	$0	$0	$0	$0
76													
77	TOT/ OTHER AMORTIZATION EXPENSES												
78		Demand				$0	$1,441	$1,182	$10,839	$0	$0	$0	$0
79		Customer				$0	$101	$351	$1,105	$0	$0	$0	$0
80		Delivery				$0	$221	$884	$11,433	$0	$0	$0	$0
81													
82	TOTAL TAXES OTHER THAN INCOME TAXES												
83		Demand				$0	$27,560	$22,610	$207,259	$0	$0	$0	$0
84		Customer				$0	$2,823	$9,839	$30,947	$0	$0	$0	$0
85		Delivery				$0	$0	$0	$0	$0	$0	$0	$0
86													
87	TOTAL OTHER REVENUES												
88		Demand				$0	$0	$0	$0	$0	$0	$0	$0
89		Customer				$0	$0	$0	$0	$0	$0	$0	$0
90		Delivery				$0	$0	$0	$0	$0	$0	$0	$0
91													
92	TOTAL RATE BASE												
93		Demand				$0	$1,952,064	$1,601,478	$14,680,027	$0	$0	$0	$0
94		Customer				$0	$177,339	$618,073	$1,944,058	$0	$0	$0	$0
95		Delivery				$0	$191	$624	$8,055	$0	$0	$0	$0
96						$0	$2,129,593	$2,220,175	$16,632,141	$0	$0	$0	$0
97	EARNED RETURN				0.08444								
98		Demand				$0	$164,832	$135,229	$1,239,581	$0	$0	$0	$0
99		Customer				$0	$14,974	$52,190	$164,156	$0	$0	$0	$0
100		Delivery				$0	$16	$53	$680	$0	$0	$0	$0
101													
102	INCOME TAX												
103		Demand					$55,513	$45,543	$417,472	$0	$0	$0	$0
104		Customer					$5,043	$17,577	$55,285	$0	$0	$0	$0
105		Delivery					$5	$18	$229	$0	$0	$0	$0
106							$60,562	$63,138	$472,986	$0	$0	$0	$0
107	**Cost of Service Margin**												
108		Demand					$376,383	$308,785	$2,830,490	$0	$0	$0	$0
109		Customer					$55,422	$193,159	$607,553	$0	$0	$0	$0
110		Delivery					$424	$1,681	$21,734	$0	$0	$0	$0
111		Check total				$0	$432,228	$503,625	$3,459,777	$0	$0	$0	$0
112													
113													
114	Peak Demand					-	$0	400	$0	-			
115													
116	Customers (unweighted) times 12					-		36		-			
117													
118	Throughput*99%					-	$0	1,137,821	$0	-	$0	$0	$0
119													
120													
121	**Unit Cost - Demand $ / GJ / Year**					**N/A**	**N/A**	**$771.96**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**
122	**Unit Cost - Demand $ / Customer / Month**												
123	**Unit Cost - Customer $ / Customer / Month**					**N/A**	**N/A**	**$5,365.53**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**
124	**Unit Cost - Delivery $ / GJ**					**N/A**	**N/A**	**$0.001**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**

	A	B	C	D	E	F	H	I	L	O	P	Q	R	S	T
1	BC Gas Utility Ltd. - Regional Studies														
2	2001 Cost of Service Study														
3	Distribution Mains Classified 75% Demand & 25% Customer														
4	"2001 Regional"														
5			(a)			(b)	(c)	(d)			(i)	(j)	(k)		
6	**Columbia Region**					**TOTAL REGION**	**Sched 1**	**Sched 2**	**Sched 3 & 23**	**Sched 5 & 25**	**Sched 4**	**Sched 7 & 27**	**Sched 6**	**Gen Firm T-Srvc. Bypass Schd 25**	**Large Volume T-Srvc. Sched 22**
7	REVENUES:														
8	Operating Revenues														
9		A. Sales Revenues				$25,596,478	$16,820,000	$5,500,600	$1,972,200	$1,303,678	$0	$0	$0	$0	$0
10		B. Transportation Revenues				$2,506,503	$0	$0	$0	$193,696	$0	$0	$0	$0	$0
11	Total Operating Revenues					$28,102,981	$16,820,000	$5,500,600	$1,972,200	$1,497,374	$0	$0	$0	$0	$0
12															
13	Less:	C. Cost of Gas				($16,530,331)	($10,254,600)	($3,702,600)	($1,394,400)	($993,638)	$0	$0	$0	$0	$0
14	Net Operating Revenues					$11,572,650	$6,565,400	$1,798,000	$577,800	$503,736	$0	$0	$0	$0	$0
15															
16	**Gross Margin**					**$11,572,650**	**$6,565,400**	**$1,798,000**	**$577,800**	**$503,736**	**$0**	**$0**	**$0**	**$0**	**$0**
17															
18	**Margin Reconciliation Adjustment (MRA)**					**$25,060**	**($12,237)**	**($3,351)**	**($1,077)**	**($939)**	**$0**	**$0**	**$0**	**$0**	**$0**
19															
20	**SCP & FV incremental increase**														
21	SCP				11.93%	$1,126,842	$783,295	$214,513	$68,935	$60,099	$0	$0	$0	$0	$0
22	FV				1.25%	$142,204	$82,246	$22,524	$7,238	$6,310	$0	$0	$0	$0	$0
23	**SCP & FV rev increase to balance COS**					$1,269,046	$865,541	$237,037	$76,173	$66,409	$0	$0	$0	$0	$0
24	**Adjusted Gross Margin excl. MRA**					**$12,841,696**	**$7,430,941**	**$2,035,037**	**$653,973**	**$570,145**	**$0**	**$0**	**$0**	**$0**	**$0**
25															
26	**Adjusted Gross Margin incl. MRA**					**$12,866,756**	**$7,418,704**	**$2,031,686**	**$652,897**	**$569,206**	**$0**	**$0**	**$0**	**$0**	**$0**
27															
28	Cost of Service														
29		Operating and Maintenance													
30			Transmission			$207,926	$73,052	$27,778	$9,916	$8,194	$0	$0	$0	$0	$0
31			Storage			$19,845	$12,189	$4,635	$1,654	$1,367	$0	$0	$0	$0	$0
32			Transmission - SCP			$36,991	$22,720	$8,639	$3,084	$2,548	$0	$0	$0	$0	$0
33			Distribution			$449,958	$300,874	$60,430	$15,163	$11,940	$0	$0	$0	$0	$0
34			Customer Accounting			$507,037	$412,446	$53,168	$6,670	$4,380	$0	$0	$0	$0	$0
35			Gas Supply Administration			$13,170	$3,471	$1,226	$499	$656	$0	$0	$0	$0	$0
36			Marketing			$157,926	$88,158	$16,149	$3,702	$3,616	$0	$0	$0	$0	$0
37			O&M excluding General & Admin			$1,392,854	$912,910	$172,025	$40,689	$32,701	$0	$0	$0	$0	$0
38															
39			General & Admin			$2,155,905	$1,298,886	$337,274	$101,800	$82,409	$0	$0	$0	$0	$0
40		Total Operating and Maintenance				$3,548,758	$2,211,796	$509,299	$142,489	$115,110	$0	$0	$0	$0	$0
41															
42		Depreciation Expense				$2,098,864	$1,226,501	$318,329	$96,057	$77,757	$0	$0	$0	$0	$0
43		Other Amortization Expenses				$108,891	$65,076	$19,187	$6,303	$5,168	$0	$0	$0	$0	$0
44															
45	Other Revenues														
46		A. Late Payment Charge				($23,703)	($16,411)	($5,367)	($1,924)	$0	$0	$0	$0	$0	$0
47		B. Revenue from Service Work				($112,533)	($77,916)	($25,481)	($9,136)	$0	$0	$0	$0	$0	$0
48		C. SCP Revenue				($330,688)	($203,107)	($77,230)	($27,569)	($22,781)	$0	$0	$0	$0	$0
49		D. Bypass Customer Revenue				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
50		Total Other Revenues				($466,923)	($297,435)	($108,078)	($38,629)	($22,781)	$0	$0	$0	$0	$0
51															
52		Taxes other than Income Tax				$1,554,168	$937,753	$252,166	$77,619	$62,998	$0	$0	$0	$0	$0
53		Income Tax				$1,794,130	$1,102,011	$289,216	$88,475	$71,314	$0	$0	$0	$0	$0
54															
55		Earned Return													
56			Rate Base			$63,088,965	$38,751,211	$10,170,035	$3,111,134	$2,507,678	$0	$0	$0	$0	$0
57			Embedded Rate of Return			8.444%	8.444%	8.444%	8.444%	8.444%	8.444%	8.444%	8.444%	8.444%	8.444%
58		Earned Return				$5,327,273	$3,272,177	$858,764	$262,706	$211,750	$0	$0	$0	$0	$0
59															
60	**Cost of Service Margin**					**$13,965,161**	**$8,517,878**	**$2,138,883**	**$635,019**	**$521,315**	**$0**	**$0**	**$0**	**$0**	**$0**
61															
62	**Margin to Cost Ratio (L26 / L60)**					**92.1%**	**87.1%**	**95.0%**	**102.8%**	**109.2%**	**N/A**	**N/A**	**0.0%**	**N/A**	**N/A**
63	**Revenue to Cost Ratio ((L26 + L13) / (L60 + L26))**						**94.1%**	**98.2%**			**N/A**		**N/A**		

	A	B	C	D	E	U	V	W	X	Y	AA	AB
1	BC Gas Utility Ltd. - Regional Studies											
2	2001 Cost of Service Study											
3	Distribution Mains Classified 75% Demand & 25% Customer											
4	"2001 Regional"											
5			(a)									
6	**Columbia Region**					**Gen Firm T-Srvc. Bypass Schd 22**	**Sched 22A**	**T-Srvc Bypass Sch 22A**	**Sched 22B**	**BC Hydro**	**PCEC**	**Other Byron Creek**
7	REVENUES:											
8	Operating Revenues											
9		A. Sales Revenues				$0	$0	$0	$0	$0	$0	$0
10		B. Transportation Revenues				$74,000	$0	$0	$2,087,807	$0	$0	$151,000
11	Total Operating Revenues					$74,000	$0	$0	$2,087,807	$0	$0	$151,000
12												
13	Less:	C. Cost of Gas				($4,000)	$0	$0	($181,093)	$0	$0	$0
14	Net Operating Revenues					$70,000	$0	$0	$1,906,714	$0	$0	$151,000
15												
16	**Gross Margin**					**$70,000**	**$0**	**$0**	**$1,906,714**	**$0**	**$0**	**$151,000**
17												
18	**Margin Reconciliation Adjustment (MRA)**					**$0**	**$0**	**$0**	**($3,554)**	**$0**	**$0**	**$46,217**
19												
20	**SCP & FV incremental increase**											
21	SCP				11.93%	$0	$0	$0	$0	$0	$0	$0
22	FV				1.25%	$0	$0	$0	$23,886	$0	$0	$0
23	**SCP & FV rev increase to balance COS**					$0	$0	$0	$23,886	$0	$0	$0
24	**Adjusted Gross Margin excl. MRA**					**$70,000**	**$0**	**$0**	**$1,930,600**	**$0**	**$0**	**$151,000**
25												
26	**Adjusted Gross Margin incl. MRA**					**$70,000**	**$0**	**$0**	**$1,927,046**	**$0**	**$0**	**$197,217**
27												
28	Cost of Service											
29		Operating and Maintenance										
30			Transmission			$3,902	$0	$0	$74,936	$0	$0	$10,149
31			Storage			$0	$0	$0	$0	$0	$0	$0
32			Transmission - SCP			$0	$0	$0	$0	$0	$0	$0
33			Distribution			$6,674	$0	$0	$54,742	$0	$0	$135
34			Customer Accounting			$3,982	$0	$0	$26,390	$0	$0	$0
35			Gas Supply Administration			$295	$0	$0	$7,022	$0	$0	$0
36			Marketing			$4,394	$0	$0	$41,907	$0	$0	$0
37			O&M excluding General & Admin			$19,247	$0	$0	$204,998	$0	$0	$10,285
38												
39			General & Admin			$28,882	$0	$0	$271,753	$0	$0	$34,901
40		Total Operating and Maintenance				$48,128	$0	$0	$476,751	$0	$0	$45,186
41												
42		Depreciation Expense				$35,054	$0	$0	$285,967	$0	$0	$59,199
43		Other Amortization Expenses				$1,215	$0	$0	$10,480	$0	$0	$1,462
44												
45	Other Revenues											
46		A. Late Payment Charge				$0	$0	$0	$0	$0	$0	$0
47		B. Revenue from Service Work				$0	$0	$0	$0	$0	$0	$0
48		C. SCP Revenue				$0	$0	$0	$0	$0	$0	$0
49		D. Bypass Customer Revenue				$0	$0	$0	$0	$0	$0	$0
50		Total Other Revenues				$0	$0	$0	$0	$0	$0	$0
51												
52		Taxes other than Income Tax				$19,250	$0	$0	$181,122	$0	$0	$23,261
53		Income Tax				$22,019	$0	$0	$203,937	$0	$0	$17,159
54												
55		Earned Return										
56			Rate Base			$774,280	$0	$0	$7,171,246	$0	$0	$603,382
57			Embedded Rate of Return			8.444%	8.444%	8.444%	8.444%	8.444%	8.444%	8.444%
58		Earned Return				$65,381	$0	$0	$605,545	$0	$0	$50,950
59												
60	**Cost of Service Margin**					**$191,047**	**$0**	**$0**	**$1,763,802**	**$0**	**$0**	**$197,217**
61												
62	**Margin to Cost Ratio (L26 / L60)**					**36.6%**	**N/A**	**N/A**	**109.3%**	**N/A**	**N/A**	**100.0%**
63	**Revenue to Cost Ratio ((L26 + L13) / (L60 + L26))**											

	A	B	C	D	E	F	H	I	L	O	P	Q	R	S	T
1	BC Gas Utility Ltd. - Regional Studies														
2	2001 Cost of Service Study														
3	Distribution Mains Classified 75% Demand & 25% Customer														
4	"2001 Regional"														
5			(a)			(b)	(c)	(d)			(i)	(j)	(k)		
6	**Columbia Region**					**TOTAL REGION**	**Sched 1**	**Sched 2**	**Sched 3 & 23**	**Sched 5 & 25**	**Sched 4**	**Sched 7 & 27**	**Sched 6**	**Gen Firm T-Srvc. Bypass Schd 25**	**Large Volume T-Srvc. Sched 22**
64															
67	TOTAL OPERATIONS AND MAINTENANCE EXPENSES														
68		Demand				$1,833,206	$888,992	$338,034	$120,669	$99,710	$0	$0	$0	$0	$0
69		Customer				$1,702,608	$1,319,471	$170,091	$21,340	$14,759	$0	$0	$0	$0	$0
70		Delivery				$12,944	$3,333	$1,174	$480	$640	$0	$0	$0	$0	$0
71															
72	TOTAL DEPRECIATION EXPENSES														
73		Demand				$1,336,896	$637,486	$242,401	$86,530	$71,501	$0	$0	$0	$0	$0
74		Customer				$761,968	$589,015	$75,929	$9,526	$6,255	$0	$0	$0	$0	$0
75		Delivery				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
76															
77	TOT/ OTHER AMORTIZATION EXPENSES														
78		Demand				$63,575	$37,804	$14,375	$5,131	$3,959	$0	$0	$0	$0	$0
79		Customer				$24,796	$20,047	$2,268	$285	$187	$0	$0	$0	$0	$0
80		Delivery				$20,520	$7,225	$2,544	$887	$1,022	$0	$0	$0	$0	$0
81															
82	TOTAL TAXES OTHER THAN INCOME TAXES														
83		Demand				$1,031,493	$522,336	$198,615	$70,900	$58,586	$0	$0	$0	$0	$0
84		Customer				$522,674	$415,416	$53,551	$6,719	$4,412	$0	$0	$0	$0	$0
85		Delivery				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
86															
87	TOTAL OTHER REVENUES														
88		Demand				($466,923)	($297,435)	($108,078)	($38,629)	($22,781)	$0	$0	$0	$0	$0
89		Customer				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
90		Delivery				$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
91															
92	TOTAL RATE BASE														
93			Demand			$39,004,179	$19,713,629	$7,494,667	$2,675,884	$2,209,321	$0	$0	$0	$0	$0
94			Customer			$22,447,132	$18,021,129	$2,315,734	$290,534	$190,801	$0	$0	$0	$0	$0
95			Delivery			$1,637,654	$1,016,453	$359,634	$144,716	$107,557	$0	$0	$0	$0	$0
96						$63,088,965	$38,751,211	$10,170,035	$3,111,134	$2,507,678	$0	$0	$0	$0	$0
97	EARNED RETURN				0.08444										
98			Demand			$3,293,513	$1,664,619	$632,850	$225,952	$186,555	$0	$0	$0	$0	$0
99			Customer			$1,895,436	$1,521,704	$195,541	$24,533	$16,111	$0	$0	$0	$0	$0
100			Delivery			$138,283	$85,829	$30,368	$12,220	$9,082	$0	$0	$0	$0	$0
101															
102	INCOME TAX														
103			Demand			$1,109,204	$560,618	$213,134	$76,097	$62,829	$0	$0	$0	$0	$0
104			Customer			$638,354	$512,487	$65,855	$8,262	$5,426	$0	$0	$0	$0	$0
105			Delivery			$46,572	$28,906	$10,227	$4,115	$3,059	$0	$0	$0	$0	$0
106						$1,794,130	$1,102,011	$289,216	$88,475	$71,314	$0	$0	$0	$0	$0
107	**Cost of Service Margin**														
108			Demand			$8,200,964	$4,014,420	$1,531,330	$546,650	$460,359	$0	$0	$0	$0	$0
109			Customer			$5,545,836	$4,378,139	$563,233	$70,664	$47,151	$0	$0	$0	$0	$0
110			Delivery			$218,320	$125,294	$44,313	$17,703	$13,803	$0	$0	$0	$0	$0
111		Check total				$13,965,120	$8,517,853	$2,138,877	$635,017	$521,313	$0	$0	$0	$0	$0
112															
113															
114	Peak Demand						18,590	7,069	2,302	1,991	-	-	-	$0	-
115															
116	Customers (unweighted) times 12						223,128	23,196	1,008	144	-	-	-		-
117															
118	Throughput*99%						2,089,184	735,651	301,154	401,277	-	-	-	$0	-
119															
120															
121	**Unit Cost - Demand $ / GJ / Year**						**$215.94**	**$216.63**	**$237.44**	**$231.19**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**
122	**Unit Cost - Demand $ / Customer / Month**						**$17.99**	**$66.02**	**$542.31**						
123	**Unit Cost - Customer $ / Customer / Month**						**$19.62**	**$24.28**	**$70.10**	**$327.44**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**
124	**Unit Cost - Delivery $ / GJ**						**$0.060**	**$0.060**	**$0.059**	**$0.034**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**

	A	B	C	D	E	U	V	W	X	Y	AA	AB
1	BC Gas Utility Ltd. - Regional Studies											
2	2001 Cost of Service Study											
3	Distribution Mains Classified 75% Demand & 25% Customer											
4	"2001 Regional"											
5			(a)									
6	**Columbia Region**					**Gen Firm T-Srvc. Bypass Schd 22**	**Sched 22A**	**T-Srvc Bypass Sch 22A**	**Sched 22B**	**BC Hydro**	**PCEC**	**Other Byron Creek**
64												
67	TOTAL OPERATIONS AND MAINTENANCE EXPENSES											
68		Demand				$32,384	$0	$0	$313,590	$0	$0	$39,827
69		Customer				$15,449	$0	$0	$156,139	$0	$0	$5,359
70		Delivery				$295	$0	$0	$7,022	$0	$0	$0
71												
72	TOTAL DEPRECIATION EXPENSES											
73		Demand				$29,367	$0	$0	$219,098	$0	$0	$50,513
74		Customer				$5,687	$0	$0	$66,870	$0	$0	$8,687
75		Delivery				$0	$0	$0	$0	$0	$0	$0
76												
77	TOT/	OTHER AMORTIZATION EXPENSES										
78		Demand				$689	$0	$0	$371	$0	$0	$1,246
79		Customer				$170	$0	$0	$1,624	$0	$0	$216
80		Delivery				$356	$0	$0	$8,485	$0	$0	$0
81												
82	TOTAL TAXES OTHER THAN INCOME TAXES											
83		Demand				$15,239	$0	$0	$146,038	$0	$0	$19,779
84		Customer				$4,011	$0	$0	$35,084	$0	$0	$3,482
85		Delivery				$0	$0	$0	$0	$0	$0	$0
86												
87	TOTAL OTHER REVENUES											
88		Demand				$0	$0	$0	$0	$0	$0	$0
89		Customer				$0	$0	$0	$0	$0	$0	$0
90		Delivery				$0	$0	$0	$0	$0	$0	$0
91												
92	TOTAL RATE BASE											
93		Demand				$600,452	$0	$0	$5,796,534	$0	$0	$513,694
94		Customer				$173,518	$0	$0	$1,365,728	$0	$0	$89,688
95		Delivery				$310	$0	$0	$8,984	$0	$0	$0
96						$774,280	$0	$0	$7,171,246	$0	$0	$603,382
97	EARNED RETURN				0.08444							
98		Demand				$50,702	$0	$0	$489,459	$0	$0	$43,376
99		Customer				$14,652	$0	$0	$115,322	$0	$0	$7,573
100		Delivery				$26	$0	$0	$759	$0	$0	$0
101												
102	INCOME TAX											
103		Demand				$17,076	$0		$164,842			$14,608
104		Customer				$4,935	$0		$38,839			$2,551
105		Delivery				$9	$0		$255			$0
106						$22,019	$0	$0	$203,937	$0	$0	$17,159
107	**Cost of Service Margin**											
108		Demand				$145,457	$0	$0	$1,333,398	$0	$0	$169,350
109		Customer				$44,904	$0	$0	$413,878	$0	$0	$27,867
110		Delivery				$686	$0	$0	$16,521	$0	$0	$0
111		Check total				$191,047	$0	$0	$1,763,797	$0	$0	$197,217
112												
113												
114	Peak Demand					$0	-	$0	20,700			
115												
116	Customers (unweighted) times 12						-		72			
117												
118	Throughput*99%					$0	-	$0	4,401,333	$0	$0	$0
119												
120												
121	**Unit Cost - Demand $ / GJ / Year**					**N/A**	**N/A**	**N/A**	**$64.42**	**N/A**	**N/A**	**N/A**
122	**Unit Cost - Demand $ / Customer / Month**											
123	**Unit Cost - Customer $ / Customer / Month**					**N/A**	**N/A**	**N/A**	**$5,748.31**	**N/A**	**N/A**	
124	**Unit Cost - Delivery $ / GJ**					**N/A**	**N/A**	**N/A**	**$0.004**	**N/A**	**N/A**	

RESIDENTIAL
RATE SUMMARY FOR NATURAL GAS UTILITIES

Utility **Effective Date/Source**	**Rate Number & Name**	**Applicability**	**Basic Minimum or Demand Charge**	**Rate Structure & Commodity Charge**	**Comments**
CANAIDAN UTILITIES					
British Columbia **PNG (NE) Ltd.** January 1, 2001	**Dawson Creek & Fort St. John Resedential Service**	To individually metered residential premises.	$7.00 /month	Uniform Rate Structure: • Margin: $1.788 /GJ Gas Cost $7.502 /GJ	
	Tumbler Ridge Residential Service	To individually metered residential premises.	$8.50 /month	• Margin: $4.555 /GJ Gas Cost $7.108 /GJ	
PNG - West, BC January 1, 2001	**Rate 1** **Residential Service**	To individually metered residential premises.	$10.75 /month	• Margin: $3.538 /GJ Gas Cost $8.459 /GJ	
Alberta **Alta Gas Utilities** January 1, 2001	**Rate 1** **Small General Service**	Small consumers using less than 4,986 GJ per year	$14.00 /month	• Uniform Seasonal Rate Structure: Commodity Charge (Nov - Mar) (Apr - Oct) Margin $1.293 /GJ $1.293 /GJ Gas Costs $10.971 $4.968	multiple rates during each season; gas costs for each season (summer and winter) based on the average number of days at each rate.
ATCO Gas - South	**Rate No. 1**	Available to customers		•	

January 24, 2001	**General Service**	using < 8,000 GJ / yr.	$13.00 /month	Uniform Seasonal Rate Structure: Commodity Charge Margin $0.952 /GJ Gas Costs $9.814 /GJ	interim rates approved January 2001
ATCO Gas - North January 24, 2001	**Rate No. 1** **General Services**	Available to customers using < 8,000 GJ / year.	$11.87 /month	• Uniform Seasonal Rate Structure: Commodity Charge Margin $1.029 /GJ Gas Costs $8.772 /GJ	interim rates approved January 2001
Saskatchewan					
SaskEnergy, SK December 1, 2000	**Rate G01** **Domestic** **Residential**	To individually metered residential premises & resort cottages.	$10.50 /month	• Uniform Rate Structure: Margin : $1.839 / GJ Gas Cost : $4.324 /GJ	Rates effective December 1, 2000
	Rate G17 **Domestic Farm**	For farm residential and agricultural use.	$11.55 /month	• Uniform Rate Structure: Margin : $1.839 / GJ Gas Cost : $4.324 /GJ	Rates Effective December 1, 2000
Manitoba					
Centra Gas, MB November 1, 2000	**Rate 1 (SGS) Small General Service**	For gas supplied via one domestic sized meter.	$10.00 /month	• Uniform Rate Structure: Margin : $3.010/ GJ Gas Cost : $4.919 /GJ	

Ontario					
Enbridge Consumers, ON October 1, 2000	**Rate 1** **Residential**	Available to any customer using gas in a residential building through one meter and containing no more than 6 dwelling units.	$10.00 /month	• Declining Seasonal Rate Structure: Margin (Nov - Mar) (Apr - Oct) First 1.16 GJ $4.095 /GJ $3.272 /GJ Next 2.12 GJ $3.936 $3.112 Next 3.28 GJ $3.810 $2.987 Next 6.56 GJ $3.717 $2.894 Gas Cost . $5.376 /GJ $5.376 /GJ	
Union Gas, ON October 1, 2000	**Rate 201** **Residential** **Fort Frances Zone**	< or = 2,000 GJ/year.	$9.00 /month	• Declining Seasonal Rate Structure: Margin (Dec - Mar) (Apr - Nov) First 3.86 GJ $2.925 $2.925 /GJ Next 7.72 GJ $2.702 $2.702 Next 7.72 GJ $2.589 $2.589 Next 19.3 GJ $2.457 $2.457 Over 38.6 GJ $0.777 $0.777 Gas Cost $5.973 $5.713 /GJ	

	Rate 101 **Residential** **Western Zone**	< or = 2,000 GJ/year.	$10.00 /month	• Declining Seasonal Rate Structure: Margin (Dec - Mar) (Apr - Nov) First 3.86 GJ $2.925 /GJ $2.925 /GJ Next 7.72 GJ $2.702 $2.702 Next 7.72 GJ $2.589 $2.589 Next 19.30 GJ $2.457 $2.457 Over 38.60 GJ $2.024 $2.024 Gas Cost $6.098 /GJ $5.839 /GJ	
Union Gas, ON October 1, 2000	**Rate 301** **Residential** **Northern Zone**	< or = 2,000 GJ/year.	$10.00 /month	• Declining Seasonal Rate Structure: Margin (Dec - Mar) (Apr - Nov) First 3.86 GJ $2.925 /GJ $2.925 /GJ Next 7.72 GJ $2.702 $2.702 Next 7.72 GJ $2.589 $2.589 Next 19.30 GJ $2.457 $2.457 Over 38.60 GJ $2.024 $2.024 Gas Cost $6.542 /GJ $6.283 /GJ	
	Rate 601 **Residential** **Eastern Zone**	< or = 2,000 GJ/year.	$10.00 /month	• Declining Seasonal Rate Structure: Margin (Dec - Mar) (Apr - Nov) First 3.86 GJ $2.925 /GJ $2.925 /Gj Next 7.72 GJ $2.702 $2.702 Next 7.72 GJ $2.589 $2.589	

				Over 38.60 GJ $2.024 $2.024 Gas Supply Charge $6.825 /GJ $6.566 /GJ	
Union Gas, ON October 1, 2000	**Rate M2 Residential** **South Western Zone**	Available to residential and non-contract commercial customers in the Company's Southern Delivery zone.	$7.50 /month	• Declining Rate Structure: Margin First 54.04 GJ $2.230 /GJ Next 177.56 GJ $1.462 Next 4 786.40 GJ $1.113 Next 10 422.00 GJ $0.838 Over 15 440.00 GJ $0.800 Gas Supply Charge $5.994 /GJ	
Quebec					
Gaz Metropolitain, PQ October 1, 1999	**Rate No. 1** **General Sales Service**	For any withdrawal of firm service gas measured at a single metering point.	Min. Daily Charge $0.30656 /m3/day	• Declining Rate Structure: Margin First 0.12 GJ $7.843 /GJ Next 0.27 GJ $6.932 Next 0.77 GJ $6.211 Next 2.70 GJ $5.523 Next 7.72 GJ $4.602 Next 27.02 GJ $3.904 Next 77.20 GJ $3.229 Next 270.20 GJ $2.683 Next 772.00 GJ $2.424 Next 2 702.00 GJ $2.164 All additional GJ $2.048	Price includes all taxes. Cost of Gas charge is based on a 12-month rolling average with an additional charge of $0.931 per m3 for the fuel gas charge. **Note:** Effective January 1, 2001 there will be an increase of 0.204 cents/m3 that will be multiplied to the total volume withdrawn by the customer

				Cost of Gas $2.765 /GJ	
AMERICAN UTILITIES **Washington**					
Avista Utilities Decmeber 1 , 2000	**Rate 101** **General Service Service**	Available to customers in Washington where gas service is available.	$7.73 /month	• Uniform Rate Structure: Total Commodity Charge : $8.690 /GJ	rate tariff sets monthly rate as $0.59311 per therm; cost of gas and margin are not broken down
Northwest Natural-WA November 1, 2000	**Rate 2** **Residential Service**	Firm sales service for separately metered single family and multi family residential space & water heating.	$6.18 /month	Declining Block Structure: Margin: First 4.22 GJ $7.092 /GJ All Additional GJ $6.388 /GJ Gas Cost $4.916 /GJ	
	Rate 24 **Residential Sales Service - all gas**	Firm sales service for residential customers for space & water heating, and equipment for domestic use.	$6.18 /month	• Declining Block Structure Margin: First 21.10 GJ $6.322 /GJ All additonal GJ $5.757 Gas Cost : $4.916 /GJ	
	Rate 27 **Residential Dry-out Service**	Firm gas for residential dwellings under construction.	N/A	• Uniform Rate Structure: Margin (all GJ) $5.294 /GJ Gas Cost : $4.916 /GJ	

Puget Sound Energy January 12, 2001	**Rate 11** **General Service**	Limited to locations and entities served as of Oct/93.	$6.89 /month	Uniform Rate Structure: • Distribution Charge : $3.822 /GJ Gas Cost $9.793 /GJ Conservation Charge : $1.333 /GJ	The conservation charge is a new addition to the rate schedule. It is part of the new gas conservation program and is not considered part of the distribution or gas cost charges.
	Rate 23 **Residential General Service**	For any residential customer throughout the territory served.	$6.89 /month	Uniform Rate Structure: • Distribution Charge : $3.295 /GJ Gas Cost $10.350 /GJ Conservation Charge : $1.333 /GJ	
	Rate 24 **Residential Space and Water Heating Service**	Available to any residential customer where gas is used as a principle means of space and water heating.	$6.89 /month	• Uniform Rate Structure: Distribution Charge : $3.295 /GJ Gas Cost $10.350 /GJ Conservation Charge : $1.333 /GJ	
Idaho					
Intermountain Gas Company (Idaho) December 1, 2000	**Rate RS-1** **Residential Service**	Available to individually metered consumers not otherwise specifically provided for using natural gas for residential purposes	**April-November:** $3.86 /month **December-March:** $10.05 /month	Uniform Seasonal Rate Structure: (Apr-Nov) (Dec-Mar) Commodity Charge $11.890 /GJ $10.241 /GJ	

Oregon **Northwest Natural Gas, OR** December 1, 2000	**Rate 2** **Residential Service**	Firm sales service for all residential customers to gas fired equipment in residential dwellings	$7.73 /month	• Uniform Rate Structure: Margin (per GJ) $7.007 /GJ Gas Cost $5.094 /GJ	
California **Southern California Gas (LA)** December 4, 1998	**GR** **Residential Service**	Applicable for natural gas procurement of service for individually metered residential customers supplied from the utility's core portfolio	$15.46 /month	Uniform Rate Structure: Transmission Charge: $3.591 /GJ Gas Cost : $9.554 /GJ	The customer charge is calculated on a daily basis (33.149 cents/day) from Nov.1 to Apr. 30 with no daily charge in effect from May 1 to October 31.
Nevada **Southwest Gas Corporation (South)** January 1, 2001	**SG-1** **Residential Gas Service**	Applicable to gas service to customers which consists of direct domestic gas usage in a residential dwelling for space heating, water heating, and other residential uses	$9.27 /month	Declining Seasonal Rate Structure: Margin (Apr-Oct) (Nov-Mar) First 3.17 GJ $3.559 /GJ $3.559 /GJ All over 3.17 GJ $2.286 $3.559 /GJ Gas Cost $6.990 $6.990	The Gas Cost is composed of 3 separate charges: 1) reservation charge component 2) commodity cost component and 3) Gas cost balancing Account Adjustment
Southwest Gas Corporation (North) January 1, 2001	**NG-10** **Residential Gas Service**	Applicable to gas service to customers which consists of direct domestic gas usage in a residential dwelling for	$9.27 /month	Uniform Rate Structure;	The Gas Cost is composed of 3 separate charges: 1) reservation charge component 2) commodity cost component and

		space heating, water heating and other residential uses		Margin : $2.952 Gas Cost : $9.684	3) Gas cost balancing Account Adjustment
New Mexico **Public Service Company of New Mexico** October 30, 2000	**Rate 10** **Residential Service**	Available to any single family residential unit served thru a single meter	$13.91 / month **Note:** called a monthly access fee	Uniform Rate Structure: Margin : $1.937 /GJ Gas Cost : $8.126 /GJ	The cost of gas component will be computed at the end of the billing month and be set in accordance with the provisions of the rate riders.
Indiana **Northern Indiana Public Service Co.** December 1, 2000	**Rate 311** **Residential Gas Service**	Available to Residential customers who are located in the area served by the company	$9.83 /month	Uniform Rate Structure : Total Commodity Charge : Next 4.74 GJ $8.179 /GJ All Over 5.28 GJ $7.604 /GJ	monthly charge includes the charge of first 5 therms
Illinois **Central Illinois Light Company** June 2, 1997	**Rate 510** **Residential Gas Service**	Available to an Individually metered Customer using gas Service primarily For a single family residence or an Individual apartment.	$15.23 /month	Declining Rate Structure: Margin : First 9.50 GJ $2.888 /GJ All Over 9.50 GJ $1.823 /GJ Gas Cost $13.071 /GJ	The cost of gas is set on a montly basis For the month of January 2001 the cost of gas is $0.8921 per therm (US)

Michigan					
Consumers energy Co. (Michigan) March 31, 2000	**Rate A** **Residential Service**	Available to any customer For Residential use	$10.05 /month	Uniform Rate Structure: Margin : $1.697 /GJ Gas Cost : $4.010 /GJ	
Kentucky					
Delta Natural Gas Company (Kentucky) November 1, 2000	**Residential**		$12.37/ month	Uniform Rate Structure Margin : $5.121 /GJ Gas Cost : $8.488 /GJ	
Tennesse					
Nashville Gas Division December 1, 2000	**Rate 311** **Residential**		$12.37 /month	Uniform Seasonal Rate Structure (Nov- Mar) (Apr-Oct) Total Commodity Charge $12.541 /GJ $12.009 /GJ	
New York					
Niagara Mohawk Power Corp (NY) August 1, 2000	**SC-1** **Residential (Heating)**	Available fore residential Purposes in an individual residence, flat Or apartment in a multiple Family Dwelling	$22.49 /month	Declining Rate Structure: Margin : Next 4.96 GJ $5.171 /GJ All over 5.28 GJ $0.771 /GJ Gas Cost $11.946 /GJ Merchant Function charge $0.326 /GJ	The merchant function charge is added to the gas supply charge on a customers bill

Maryland					
Columbia Gas of Maryland Inc April 12, 2000	**Rate RS** **Residential Service**	Available at one location for the total Requirements of any residential Customer	$14.30 /month	Uniform Rate Structure: Total Commodity Charge : $3.943 /GJ	
Pennsylvania					
Columbia Gas of Pennsylvania Inc October 1, 2000	**Residential Sales**	Available ,at one location, for the Total requirements of any Residential customer	$16.71/ month	Uniform Rate Structure : Margin : $5.132 /GJ Gas Cost : $7.352 /GJ	
New Hampshire					
KeySpan Energy - New Hampshire December 1, 2000	**Rate DH** **Domestic Heating Sales**	For domestic use of gas as the Principle household heating fuel	$12.20 /month	Declining Seasonal Rate Structure : (Nov-Mar) Margin Cost of Gas First 8.44 GJ $5.229 /GJ $9.865 /GJ Over 8.44 GJ $4.447 /GJ $9.865 /GJ (Apr-Oct) All GJ $2.283 /GJ $7.994 /GJ	monthly charge is in effect per meter in household

Northern Utilities Natural Gas- NH Winter 2000-2001	**R5** **Residential Heating**		$10.68 /month	Declining Rate Structure : Margin: First 7.91 GJ $5.672 /GJ All Over 7.91 GJ $4.719 /GJ Gas Cost $10.148 /GJ	These charges are in effect during the peak periods between November-April
Massachusetts **Bay State Gas - Massachusetts** Winter 2000 Rates	**R & T 3** **Residential Heating**		$11.55 /month	Declining Rate Structure : Margin: First 9.50 GJ $6.018 /GJ All Over 9.50 GJ $3.199 /GJ Gas Cost : $11.350 /GJ	
New Jersey **New Jersey Natural Gas Company** December 1, 2000	**Rate RS** **Residential Service**	Available to any residential customer in the territory served by the company for domestic purpose	$10.11 /month	Uniform Rate Structure : Total Commodity Charge : $8.892 /GJ	
North Carolina December 1, 2000		individually metered		Uniform Seasonal Rate Structure: Total Commodity Rate : (Nov-Mar) (Apr-Oct) $13.756 /GJ $13.389 /GJ	

South Carolina					
South Carolina Electric & Gas Co. November 1, 2000	**Rate 32** **Firm Residential**	Available to residential customers using the company's service in private residences	$4.63 / month	Uniform Seasonal Rate Structure: Total Commodity Rate: (Nov-Apr) (May- Oct) First 2.63 GJ $14.839 /GJ $14.839 /GJ Over 2.63 GJ $15.795 /GJ $13.883 /GJ	
Florida					
Peoples Gas (Non-West Florida Region) November 1, 2000	**Rate RS** **Residential Service**	Gas Service for residential purposes in individually metered residences and separately metered apartments	$10.82 /month	Uniform Rate Structure : Total Commodity Charge : $6.025 /GJ	

GENERAL SERVICES/SMALL COMMERCIAL
RATE SUMMARY FORNATURAL GAS UTILITIES

Utility **Effective Date/Source**	**Rate Number & Name**	**Applicability**	**Basic Minimum or Demand Charge**	**Rate Structure & Commodity Charge**	**Comments**
CANADIAN UTILITIES					
British Columbia					
PNG (NE) Ltd January 1, 2001	**Dawson Creek** **Small Commercial**	Avail. to cust. using < 6,000 GJ/year.	$7.00 /month	- Uniform Rate Structure: Margin: $1.294 /GJ Gas Cost $7.464 /GJ	
	Tumbler Ridge Small Commercial	Avail. to cust. using < 6,000 GJ/year.	$8.50 /month	- Uniform Rate Structure: Margin: $4.172 /GJ Gas Cost $7.108 /GJ	
PNG - West, BC January 1, 2001	**Rate 2** **General Service**	For firm gas supplied through single service line & through 1 meter for use in approved appliances in commercial or institutional operations.	$10.75 /month	- Uniform Rate Structure: Margin: $3.175 / GJ Gas Cost $8.408 /GJ	

Alberta **Alta Gas Utilities, AB** January 1, 2001	**Rate 1** **Small General Service**	Available to all customers except those who do not purchase their total gas requirements from the Company.	$14.00 /month	• Uniform Rate Structure: Commodity Charge (Nov - Mar) (Apr –Oct)) Margin $1.293 /GJ $1.293 /GJ Gas Cost 10.971 /GJ $4.968 /GJ	multiple rates during each season; gas costs for each season (summer and winter) based on the average number of days at each rate.
ATCO Gas - South, AB January 24, 2001	**Rate 1** **General Service**	Available to customers using < 8,000 GJ / year.	$13.00 /month	• Uniform Seasonal Rate Structure: Commodity Charge Margin $0.952 /GJ Cost of Gas $9.814 /GJ	interim rates approved January 2001
ATCO Gas - North, AB January 24, 2001	**Rate 1** **General Services**	Available to customers using < 8,000 GJ / year.	$11.87 /month	• Uniform Seasonal Rate Structure: Commodity Charge Margin $1.029 /GJ Cost of Gas $8.772 /GJ	interim rates approved January 2001
Saskatchewan **Saskenergy, SK** December 1, 2000	**Rate G02** **General Service II**	For commercial customers using 0 - 100,000 m3 / year (< 3,860 GJ per year).	$17.00 /month	• Uniform Rate Structure: Margin : $1.635 /GJ Gas Cost : $4.324 /GJ	

Manitoba **Centra Gas, MB** November 1, 2000	**Rate 1 (SGS)** **Small General Service**	For gas supplied via one domestic sized meter on a firm basis.	$10.00 /month	• Uniform Rate Structure: Margin : $3.010 / GJ Gas Cost : $4.919 / GJ	
Ontario **Enbridge Consumers, ON** October 1, 2000	**Rate 6** **General Service**	Available to customers needing to use the Co.'s natural gas distribution network to have a supply of natural gas transported to a single location, other than residential.	$18.00 /month	• Declining Seasonal Rate Structure: Commodity Charge Margin (Dec - Mar) (Apr - Nov) First 1.16 GJ $3.687 /GJ $2.818 /GJ Next 2.12 GJ $3.552 $2.683 Next 50.76 GJ $3.403 $2.534 Next 54.04 GJ $3.241 $2.372 Next 108.08 GJ $3.079 $2.210 Over 216.16 GJ $2.836 $1.967 Gas Cost: $5.383 /GJ $5.383 /GJ	
Union Gas, ON October 1, 2000	**Rate 01** **Small Volume General Service Fort Frances Zone**	< or = 2,000 GJ/year.	$9.00 /month	• Declining Seasonal Rate Structure: Commodity Charge Margin (Dec - Mar) (Apr - Nov) First 3.86 GJ $2.925 /GJ $2.925 /GJ Next 7.72 GJ $2.702 $2.702 Next 7.72 GJ $2.589 $2.589 Next 19.30 GJ $2.457 $2.457 Over 38.60 GJ $0.777 $0.777 Gas Cost: 5.973 / GJ $5.713 / GJ	

	Rate 01	< or = 2,000 GJ/year.		• Declining Seasonal Rate Structure:			
	Small Volume General Service Western Zone		$10.00 /month	Commodity Charge			
				Margin	(Dec - Mar)	(Apr - Nov)	
				First 3.86 GJ	$2.925 /GJ	$2.925 /GJ	
				Next 7.72 GJ	$2.702	$2.702	
				Next 7.72 GJ	$2.589	$2.589	
				Next 9.30 GJ	$2.457	$2.457	
				Over 8.60 GJ	$2.024	$2.024	
				Gas Cost:	$6.098 / GJ	$5.839 / GJ	
Union Gas, ON	**Rate 01**	< or = 2,000 GJ/year.		• Declining Seasonal Rate Structure:			
October 1, 2000	**Small Volume General Service Northern Zone**		$10.00 /month	Commodity Charge			
				Margin	(Dec - Mar)	(Apr - Nov)	
				First 3.86 GJ	$2.925 /GJ	$2.925 /GJ	
				Next 7.72 GJ	$2.702	$2.702	
				Next 7.72 GJ	$2.589	$2.589	
				Next 9.30 GJ	$2.457	$2.457	
				Over 8.60 GJ	$2.024	$2.024	
				Gas Cost:	$6.542 / GJ	$6.283 / GJ	
	Rate 01	< or = 2,000 GJ/year.		• Declining Seasonal Rate Structure:			
	Small Volume General Service Eastern Zone		$10.00 /month	Commodity Charge			
				Margin	(Dec - Mar)	(Apr - Nov)	
				First 3.86 GJ	$2.925 /GJ	$2.925 /GJ	
				Next 7.72 GJ	$2.702	$2.702	
				Next 7.72 GJ	$2.589	$2.589	
				Next 19.30 GJ	$2.457	$2.457	
				Over 38.60 GJ	$2.024	$2.024	
				Gas Cost:	$6.825 / GJ	$6.566 / GJ	

Union Gas, ON October 1, 2000	**Rate M2** **General Service**	Available to residential and non-contract commercial and industrial customers in the Company's Southern Delivery Zone.	$7.50 /month	• Declining Rate Structure: Margin First 54.04 GJ $2.230 /GJ Next 177.56 GJ $1.462 Next 4 786.40 GJ $1.113 Next 10 422.00 GJ $0.838 Over 15 440.00 GJ $0.800 Gas Cost $5.994 / GJ	
Quebec					
Gaz Metropolitain, PQ October 1, 1999	**Rate No. 1** **General Sales** **Service**	For any withdrawl of firm Service gas measured at a single metering point.	Min. Daily Charge $0.29932 /m3/day	• Declining Rate Structure: Margin First 0.12 GJ $7.843 /GJ Next 0.27 GJ $6.932 Next 0.77 GJ $6.211 Next 2.70 GJ $5.523 Next 7.72 GJ $4.602 Next 27.02 GJ $3.904 Next 77.20 GJ $3.229 Next 270.20 GJ $2.683 Next 772.00 GJ $2.424 Next 2 702.00 GJ $2.164 All additional $2.048 Gas Cost : $2.765 /GJ	Price includes all taxes. Cost of Gas charge is based on a 12-month rolling average with an additional charge of $0.931 per m3 for the fuel gas charge. Note: rate filimg is currently underway for effective date of October 1 , 2000 with proposed increase of 0.204 cents/m3 multiplied to the total volume withdrawn by the customer .

AMERICAN UTILITIES **Washington**					
Avista Corporation, WA December 1, 2000	**Rate 101** **General Firm Service**	Firm gas service for any purpose when all such service is supplied at one point of delivery through a single meter.	$7.73 /month	• Uniform Rate Structure Total Commodity Charge $8.690 /GJ	Tariff sets rate as $0.59311 / therm ; cost of gas and margin are not broken down
Northwest Natural Gas, WA November 1, 2000	**Rate 1** **General Service**	Firm sales service available to residential, commercial, institutional and industrial customers for water, heating & other gas equipment.	N/A	• Declining Rate Structure: Margin : Commodity First 0.21 GJ $45.568 /GJ $7.326 /GJ Next 5.06 GJ $9.694 $4.916 All Over $9.242 $4.916	
Puget Sound Energy August 1, 2000	**Rate 31** **Commercial and Industrial General Service**	Available to any commercial or industrial customer throughout the territory served.	$15.30 /month	• Uniform Rate Structure Total Commodity Charge $10.456 /GJ	All gas used @ $0.71365 per therm
Oregon					
Northwest Natural Gas, OR December 1, 2000	**Rate 1** **General Service**	For residential, commercial and industrial customers with gas supplied at one point of delivery and through one meter.	$7.73 /month	• Uniform Rate Structure Total Commodity Charge $12.141 /GJ	Tarriff sets rate as $0.82859 per therm ; cost of gas and margin are not broken down

Nevada					
Southwest Gas Corporation (South) January 1, 2001	**SG-5(S)** **Small General Gas Service**	Applicable to commercial,industrial customers whose average monthly requirements on annual basis are less than or equal to 63.3GJ per month	$30.92 /month	uniform Rate Structure: Margin : $2.912 /GJ Gas Cost: $6.990 /GJ	
Southwest Gas Corporation (North) January 1, 2001	**NG-22(S)** **Small General Gas Service**	Applicable to commercial,industrial customers whose average monthly requirements on annual basis are less than or equal to 63.3GJ per month	$30.92 /month	Uniform Rate Structure: Margin: $2.912 /GJ Gas Cost : $9.684 /GJ	
Indiana					
Northern Indiana Public Service Co. December 1, 2000	**Rate 321** **General Service-Small**	Available to non-residential customers served by the Company	$9.38 /month	Declining Rate Structure: Total Commodity Charge: Next 5.80 GJ $8.731 /GJ Nexrt 14.77 GJ $7.861 /GJ All over 21.1 GJ $7.092 /GJ	Monthly customer charge includes charge for first 5 therms or 0.5275 GJ of gas
Illinois					
Central Illinois Light Company June 2, 1997	**Rate 550** **Small General Gas Service**	Available to any customer using gas for general purposes Annual usage not to exceed 2,637 GJ	$30.92 /month	Declining Rate Structure: Margin : First 15.8 GJ $3.149 /GJ All over 15.8 GJ $1.836 /GJ Gas Cost : $13.071 /GJ	The cost of gas is adjusted on a monthly basis ; for the month of january the cost of gas charge is $0.8921 per therm (US)

Michigan **Consumers Energy Co. (Michigan)** April 1, 1998	**Rate B** **General Service**	Available to any customer for non residential usage	$23.19 /month	Uniform Rate Structure : Margin : $1.493 /GJ Gas Cost : $4.010 /GJ	
Kentucky **Delta Natural Gas Company Inc** November 1, 2000	**Small non-residential General Service**	no detailed summary is listed	$26.28/ month	Declining Rate Structure Margin: First 0.11 - 218.7 GJ $5.121 /GJ Next 218.8-1093.5 GJ $3.393 /GJ Over 1093.5 GJ $2.897 /GJ Gas Cost : $8.488 /GJ	
Tenessee **Nashville Gas Division** December 1, 2000	**Rate 321** **Small General Service**		$34.01 /month	Uniform Seasonal Rate Structure : (Nov-Mar) Apr-Oct) Total Commodity Charge $13.209 /GJ $12.681 /GJ	
New York **Niagara Mohawk Power Corporation** August 1, 2000	**SC-2** **Small General Delivery Service**	Applicable for all purposes except those listed in SC-1(residential). Annual Consumption of less than 5,275 GJ. Service area of Village of East Syracuse, Town of Dewitt, Onondaga,NY	$29.59 /month	Declining Rate Structure: Margin : Next 29.2 GJ $3.359 /GJ Next 497.9 GJ $2.161 /GJ Over 527.5 GJ $0.328 /GJ	Monthly customer charge includes first three therms (0.3165 GJ) or less

				Gas Cost : $11.946 /GJ	
Pennsylvania **Columbia Gas of Pennsylvania** October 1, 2000	**Rate SGS** **Small General Service**	Available at one location for the total requirements are less than 6500 GJ per year	$22.46 /month $34.94 /month	Declining Rate Structure : Margin : First 54.5 GJ $4.799 /GJ All Over 54.5 GJ $4.738 /GJ Gas Cost $7.424 /GJ	
New Hampshire **Northern Utilities Natural Gas- NH** Winter 2000-2001	**GH:1** **Comm & Indust & Municipal Space Heat**		$19.85 /month	Declining Rate Structure Margin First 79.1GJ $4.322 /GJ All over 79.1 GJ $3.077 /GJ Gas Cost $10.148 /GJ	
Massachusetts **Bay State Gas - Massachusetts** Winter 2000 Rates	**Rate G & T51** Commercial & Indus.	Annual Use between 528 to 4,220 GJ	$69.62 /month	Declining Rate Structure: Margin : First 74 GJ $2.642 /GJ All over 74 GJ $2.066 /GJ Cost of Gas 10.509 /GJ	
North Carolina **Piedmont Natural Gas (NC)** December 1, 2000	**Rate 102** **Small General Service**	Available to any non-residential customer in the state of NC whose daily requirement does not exceed 50 dekatherms/day	$25.51 /month	Declining Rate Structure: Total Commodity Rate : (Nov-Mar) (Apr-Oct) First 527.5 GJ $12.963 /GJ $11.788 /GJ All Over 527.5 GJ $12.154 /GJ $10.523 /GJ	

Florida **Peoples Gas (Non-West Florida)** November 1, 2000	**Rate GS** **General Service**	Gas delivered to commercial/ industrial customer using 105.5GJ to 2,638 GJ or less per year	$26.28 /month	Uniform Rate Structure: Total Commodity Charge $3.571 /GJ	
North Carolina **Piedmont Natural Gas (NC)** December 1, 2000	**Rate 102** **Small General Service**	Available to any non-residential customer in the state of NC whose daily requirement does not exceed 50 dekatherms/day	$25.51 /month	Declining Rate Structure: Total Commodity Rate (Nov-Mar) (Apr-Oct) First 527.5 GJ $12.963 /GJ $11.788 /GJ All Over 527.5 GJ $12.154 /GJ $10.523 /GJ	
Florida **Peoples Gas (Non-West Florida)** November 1, 2000	**Rate GS** **General Service**	Gas delivered to commercial/ industrial customer using 105.5GJ to 2,638 GJ or less per year	$26.28 /month	Uniform Rate Structure: Total Commodity Charge : $3.571 /GJ	