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BC Gas Inc.

June 17, 2002

Mr. R.J. Pellatt
B.C. Utilities Commission
6th floor - 900 Howe Street
Vancouver, B.C
V6Z 2N6.

Dear Mr. Pellatt:

RE: BC Gas 2003 Revenue Requirement Application and Performance-Based Ratemaking Proposal

Enclosed is the BC Gas Utility Ltd. ("BC Gas") 2003 Revenue Requirement Application. This Application follows the conclusion of the multi-year Performance Based Rate plan that was in effect 1998 to 2001; and the withdrawal of the BC Gas 2002 Revenue Requirement Application.

The Application requests approval for an increase in revenue requirements equivalent to 1.25% of total current revenues or a 3.29% increase as a percentage of delivery margin, effective January 1, 2003. Of the 3.29%, 2.85% is due to reduced consumption by residential and commercial customers. BC Gas proposes to recover the 2.85% deficiency from these customer classes as in the normal course variances from forecast revenues are recovered from, or credited to, those customers through the operation of the Rate Stabilization Adjustment Mechanism. The remaining customer classes, subject to rate increases, would see an increase in their delivery charge of 0.95%.

The Application represents a fair and reasonable recovery of the Company's 2003 projected costs of serving its customers. The information submitted with this filing demonstrates that the Company has operated efficiently and effectively in the provision of its services to customers. The proposed rates for 2003 also establish an appropriate base upon which a multi-year PBR settlement can be established. In this regard, this Application sets out a mechanism for the setting of delivery charges at a low and stable level for the next 5 years; namely, 2003-2007. This proposal sets out the basic structure of the regulatory framework that BC Gas believes best satisfies the interests of stakeholders. The parameters of this mechanism are not fully defined in this Application, as BC Gas believes that these are more appropriately determined through a negotiated settlement process. This would be consistent with the Commission's initiatives in advancing the regulatory process in B.C. which have most recently been reinforced in the Interim Report of the Task Force on Energy Policy. Accordingly, BC Gas requests that the BCUC establish a process for achieving a negotiated settlement of the Company's revenue requirements for a multi-year period based on the PBR proposal set out in this Application.

Please contact the writer for any further information.

Yours very truly,

BC GAS UTILITY LTD.

Original signed by David M. Masuhara

David M. Masuhara

Cc Interested Parties

BC GAS UTILITY LTD.

2003 REVENUE REQUIREMENT APPLICATION AND PERFORMANCE-BASED RATEMAKING

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IN THE MATTER OF THE “UTILITIES COMMISSION ACT”
R.S.B.C. 1996, CHAPTER 473

AND IN THE MATTER OF AN APPLICATION BY
BC GAS UTILITY LTD. TO AMEND ITS SCHEDULE OF RATES

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

APPLICATION

BC Gas Utility Ltd. (“BC Gas” or the “Company”) hereby applies pursuant to the provisions of the *Utilities Commission* Act, R.S.B.C. 1996, Chapter 473 and amendments thereto (the “Act”), and in particular sections 58 and 61, to amend its Rate Schedules filed pursuant to the provisions of the Act in accordance with this Application (the “Application”); such amendments to be effective January 1, 2003. BC Gas applies to amend its Rate Schedules on the basis that the existing Schedules of Rates will be insufficient to allow BC Gas the opportunity to recover its cost of service and earn a fair and reasonable return on its invested capital.

In respect of this Application, BC Gas submits that:

A. BC Gas is incorporated under the laws of the Province of British Columbia. BC Gas’ head office is located at 1111 West Georgia Street, Vancouver, B.C. The Company is a wholly owned subsidiary of BC Gas Inc.

B. BC Gas is the largest natural gas distribution utility in British Columbia, providing sales and transportation services to more than 765,000 residential, commercial and industrial customers in over 100 communities throughout the Province. BC Gas’ distribution network delivers gas to approximately 90 percent of the natural gas customers in British Columbia (see System Map attached).

C. By Order G-123-01 dated November 21, 2001, the Commission approved the BC Gas withdrawal of its 2002 Revenue Requirements Application, and directed BC Gas to “provide its Revenue Requirements Application for 2003 with sufficient information on a stand-alone basis to establish base year revenue requirements for a multi-year PBR rate setting”.

BC Gas has determined that its current rates are insufficient and accordingly an amendment to the schedule of rates to provide a revenue requirement increase is required. In the materials filed herewith, BC Gas seeks Commission approval for the following:

1. BC Gas seeks an increase effective January 1, 2003 of approximately $15.4 million in annual revenue, or approximately 1.25% as a function of overall revenue. As a percentage of delivery margin, the increase being sought is 3.29%.

2. The most significant cause of the increase is a reduction in the average consumption of natural gas by the Revenue Stabilization Account Mechanism ("RSAM") Customers, namely Rate 1 (Residential) and Rates 2, 3 and 23 (Commercial) customers. BC Gas seeks to recover the revenue deficiency related to the reduced consumption of RSAM from those customers and the balance of the revenue deficiency from all customer classes that are subject to rate adjustments. Accordingly, BC Gas seeks an order to increase the delivery margin portion of the rates by 3.80% for RSAM Customers and to increase the delivery margin portion of the rates of non-RSAM Customers by 0.95%.

3. BC Gas has contracts in place with customers under which the rate for transportation service is set on a "bypass" basis, as well as other special contracts for service under which the rate varies from the approved standard tariff rates. The rates for service under those contracts are not subject to the increase being sought in this Application. A listing of those contracts is set out under Section H, Tab 7 of this Application.

4. The rates applicable to the Fort Nelson Service Area of BC Gas are not affected by this Application.

5. BC Gas seeks approvals from the Commission with regard to deferral accounts as set out in Section H, Tab 3, pages 5.1 to 5.5, and as discussed in Section E, including:

   - inclusion of a financing cost for variances between the forecast and actual balances in the RSAM account. The variances would attract the Company's short-term interest rate and be credited or debited, whichever the case may be, against the RSAM account;

- a deferral account to collect variances between actual and forecast property taxes and to collect variances in other government taxes, charges and levies, both direct and indirect, from those embedded in the rates approved as a result of this Application. The deferral account would attract the Company's short-term interest rate. The Company is being reassessed for BC Corporation Capital Tax for the Years from 1995 forward. While these reassessments will be appealed, BC Gas seeks to collect in this deferral account the costs of the appeal process and the amount of any net reassessments owing. The Company requests three-year amortization through a rate rider commencing on January 1, 2004 of any net deferred balance in this account;

6. This Application seeks an order approving the continuation of the regulatory accounting method as set out in the previous Performance Based Rate Plan relating to projects approved pursuant to Certificates of Public Convenience and Necessity (CPCNs). The previous Plan states: "To the extent such CPCN applications are approved and the capital projects undertaken, the capital project will form part of the rate base of BC Gas in the year following the year in which the capital project is completed. BC Gas will be entitled to accrue AFUDC on the expenditures associated with the capital project until the capital project is part of rate base."

7. The events of September 11, 2001 have affected BC Gas insurance coverage, including:

   - the coverage for events such as war and terrorism has become extremely expensive, and

   - the coverage for damages and business interruption now has much higher deductibles and/or higher cost.

   BC Gas has elected not to make these additional insurance expenditures and instead requests a deferral account to collect any losses that arise if such events occur. The deferral account would attract the Company's short-term interest rate.

8. BC Gas seeks approval of certain tariff changes to the General Terms and Conditions of the Tariff and in the area of Industrial and Transportation Services, more specifically described and discussed in Section F.

9. The Commission has established a separate procedure for setting the rate of return on common equity for BC Gas and other public utilities regulated by the Commission through the Commission's Return on Common Equity Adjustment Mechanism. The materials filed with this Application utilize the return on common equity of 9.13% that would be applicable in 2002 for BC Gas but for the Company's withdrawal of its revenue requirement for 2002. Any revisions to the rates of BC Gas relating to an adjustment to the return on common equity are not incorporated in the Application and will be separate from and in addition to the rate adjustments reflected in this Application.

10. BC Gas seeks the establishment of a longer-term comprehensive rate setting methodology with 2003 serving as the base year for a multi-year mechanism, as discussed in Section G.

11. It is BC Gas' view that a process that enhances dialogue and understanding between parties is preferred over a formal hearing process that is based on the adversarial system. BC Gas requests a Commission-endorsed Negotiated Settlement Process for the determination of the Company's 2003 revenue requirement and a multi-year comprehensive performance based regulatory mechanism. Any settlement arising pursuant to that process would require approval by the Commission.

12. BC Gas suggests that the process relating to this Application commence with a Commission-ordered Workshop at which a Negotiated Settlement Process can be determined for the review of this Application and the establishment of a multi-year comprehensive performance based regulatory mechanism.

All of which is respectfully submitted.

Dated at Vancouver, British Columbia, this 17th day of June 2002.

BC GAS UTILITY LTD.

Original signed by David M. Masuhara

David M. Masuhara, Vice President
Regulatory, Environment & Safety,
Supply Chain & Logistics

All Notices and communications in connection with this Application should be directed to:

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EXECUTIVE SUMMARY

BC Gas Utility Ltd. ("BC Gas" or the "Company") is seeking an increase in its rates for delivery service of 1.25% on total revenues, effective January 1, 2003. This increase is required to ensure that the Company's revenues recover the costs of serving customers. In addition, the Company seeks British Columbia Utilities Commission (the "Commission") approval of a negotiated settlement process to determine its 2003 rates in conjunction with a negotiated settlement process to establish a comprehensive multi-year performance based ratemaking ("PBR") plan for 2003 to 2007.

This Application reviews the business drivers, capital and operating and maintenance requirements of the Company for 2003 and its performance on key measures since 1998. The performance results show that the Company maintained its high standard of providing safe, reliable and efficient service to customers over the last five years. On measures such as operating costs, customers served per employee, and service quality indicators, the results also show that the Company performed very favourably in terms of external measures.

The Company's strong performance is especially noteworthy in view of challenges faced over the last five years. These include:

- Customer support and effective management of gas costs during a period of dramatic and volatile gas commodity price increases;
- transition of customer care and billing from B.C. Hydro to CustomerWorks;
- continuation of operational and environmental stewardship;
- negotiation of a bypass agreement with B.C. Hydro that contributes significant firm revenues;
- construction of the 300 kilometre Southern Crossing Pipeline Project on time and under budget; and
- achievement of operational efficiencies, including a reduction in workforce by over 20% without any reduction its service quality measures.

The Company's focus on customers and communities has continued and can be seen through its efforts in providing customer programs such as the Hot Tips booklets, Furnace

Tune-Up program and Heating Upgrade Promotion; as well as building stronger relationships with communities through participation in local initiatives and organizations such as in fire, search and rescue; emergency preparedness; environment and business.

Since 1997, the Company has invested over $1 billion of capital in British Columbia and provided employment to over 1300 employees throughout the province.

The Application seeks rates for 2003 that would also serve as a base year for the development of a PBR plan. BC Gas has set out in the Application a proposed multi-year framework. These are discussed below.

1. 2003 REVENUE REQUIREMENT

The revenue requirement increase sought in this Application is based on a review of the forecast needs for 2003. It is consistent with Commission Order G-123-01, which directed BC Gas "to provide its revenue requirement application for 2003 with sufficient information on a stand-alone basis to establish base year revenue requirements for a multi-year PBR rate setting".

The increase requested in this Application applies to rates for transportation service and to the delivery portion of rates for customers to whom BC Gas delivers the natural gas commodity; it does not include the gas commodity component of customer rates, which is the largest component of customers' bills. Gas commodity changes are dealt with separately by the Commission. As well, a change resulting from the Commission's return on equity ("ROE") automatic adjustment mechanism is not reflected, as such a change does not arise until December 2002. The current Commission authorized return on equity for 2002 of 9.13% has been used. The ROE for 2003 arising under the Commission mechanism will be a further adjustment to the rates sought in this Application.

The increase for 2003 is primarily required to offset a shortfall in revenue resulting from the reduced consumption of gas by the Company's residential and commercial customers. The Company's revenues are reduced as customers respond to high gas prices and take advantage of demand side management initiatives, including Company-sponsored conservation programs, to reduce their overall gas bills. In 2000, residential customers consumed an average of 113 gigajoules ("GJ") per year. The recent experience of BC Gas indicates that consumption of residential customers has declined significantly and is in the range of approximately 101 to 104 GJ per year. Consumption by commercial customers has also decreased in a similar manner. Given the significance of this drop in consumption and the uncertainty of its duration, BC Gas is using an average annual consumption of 108 GJ per year by residential customers for the purposes of setting rates in this Application. A similar proportional decrease in annual consumption is included in the forecast consumption by commercial customers. Using a consumption rate of 108 GJ, rather than 101 to 104 GJ, has the effect of reducing the amount of the revenue requirement and the associated rate increase.

Variances from the forecast of annual gas consumption by residential and commercial customers (Rates 1, 2, 3 and 23) are captured in a deferral account established by order of the Commission and referred to as the Revenue Stabilization Adjustment Mechanism (or “RSAM”) deferral account. Under the RSAM, if the consumption of gas by the Rate 1, 2, 3 and 23 customers (the “RSAM Customers”) varies from the consumption levels used to establish rates, then the variance in delivery margin collected by the Company is placed in the RSAM deferral account. This variance is then recovered from, or credited to, RSAM Customers over the next three years by way of “riders” to Rates 1, 2, 3 and 23.

The 1.25% increase in total revenues applied for in this Application is equivalent to a 3.29% increase on the delivery margin portion of rates. Delivery margin is equal to the total revenue less gas commodity costs.

Of the 3.29% increase in delivery margin being sought in this Application, 2.39% relates to the reduction in the forecast consumption of RSAM Customers. In the absence of this Application, the deficiency in delivery margin resulting from the reduction in the consumption by RSAM Customers would be recovered from those customers through the RSAM riders. Accordingly, BC Gas proposes to recover the delivery margin deficiency that is associated with the forecast reduction in the consumption of RSAM Customers directly from those customers. The result is an increase in the delivery margin of RSAM Customers of 3.80% and an increase in the delivery margin of other customers of 0.95%. Since the delivery margin deficiency associated with the forecast reduction in the consumption by RSAM Customers will be recovered from these customers as part of this Application, these customers will have a correspondingly lesser amount recovered from them via RSAM riders. Should the decrease in use be less than forecast, RSAM customers will benefit through credits to the RSAM account and riders.

While the Company is seeking an increase in delivery rates, it should be noted that even with the increase, average residential bills will be lower than they would have been had consumption remained at pre-2001 levels. When the annual bill for a residential customer based on the 112.8 GJ consumption level approved for calculation of 2002 rates is compared to the average annual bill at the new lower consumption level (108 GJ), and the applied-for rate increase is taken into account, the average annual bill for residential customers is lower by approximately $28.

Capital and operating and maintenance (“O&M”) costs are the most significant components of BC Gas’ total revenue requirement. During the incentive-based PBR plan under which BC Gas operated for the last four years, BC Gas has achieved significant savings by reducing its O&M costs. BC Gas has reduced its workforce by over 20% since 1997. Although under past PBR Plans the incentives to reduce capital spending were lower than the incentives relating to O&M, BC Gas has taken steps to ensure that capital spending is prioritized so that it is put to its best use and the impact on customers’ rates is minimized.

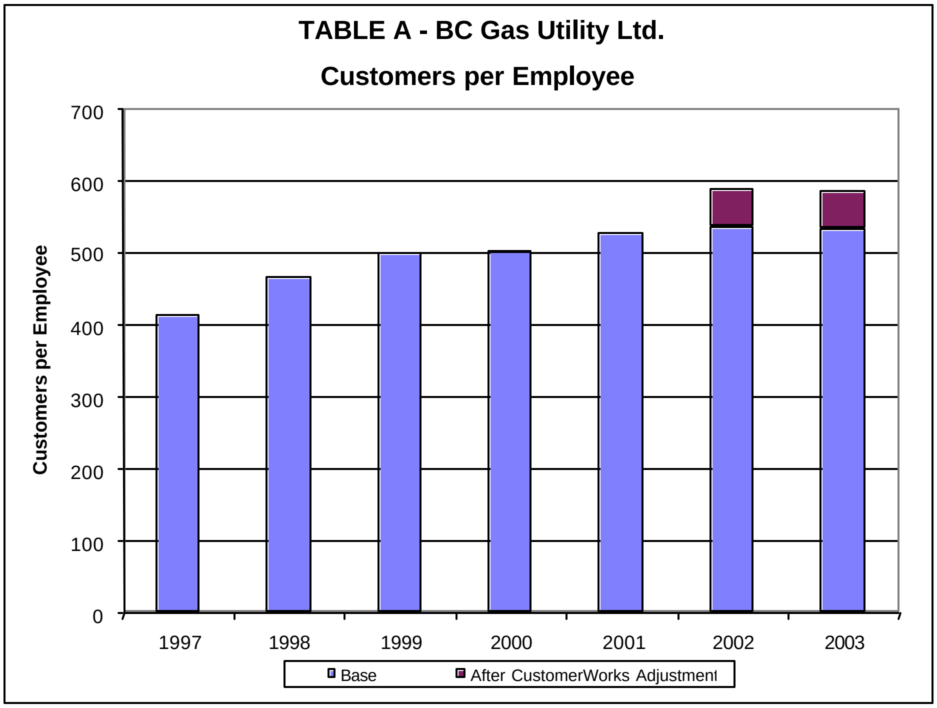
BC Gas believes that the revenue requirement increase requested is prudent and reasonable.

2. COMPARATIVE ANALYSIS

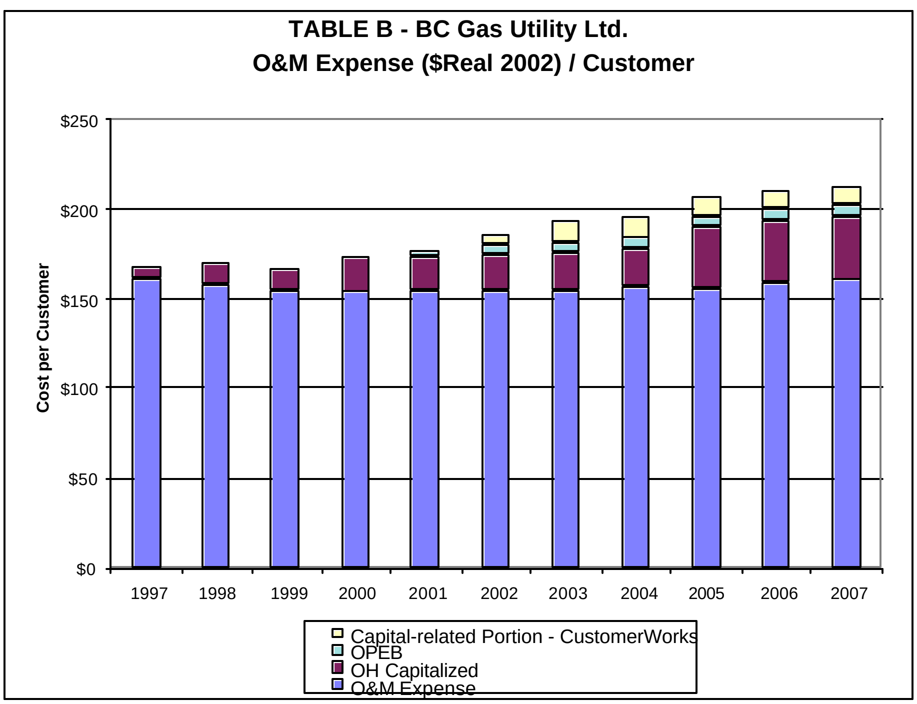
Comparative measures supporting the reasonableness of BC Gas’ O&M and capital costs are provided as part of this Application. The results of these studies indicate that BC Gas has performed favourably.

Comparisons provide a way to view Company results over time as well as relative to external groups. Both have been done.

The Company has continuously improved its base operating costs/customer ratio since 1998. One high-level measure of a company’s productivity is the number of customers served per employee. As mentioned earlier, the Company has reduced its workforce over 20% since 1997. A high ratio of customers/employee is desirable as long as service levels are maintained. As demonstrated in Table A below, BC Gas customers have been the beneficiaries of continuously improving customer/employee ratios. This has been achieved while service quality levels have been maintained or improved.



In terms of O&M/customer, BC Gas has continued to improve this ratio as can be seen in the table below. After netting out the effect of the overheads capitalization and other accounting changes and the portion of the CustomerWorks charges formerly in BC Gas' rate base, BC Gas has reduced its O&M costs per customer between 1997 and 2002 on a real basis, from $161 to $155 (see the grey shaded area in the table below):



External reviews are also included to provide a comparison of BC Gas' performance relative to Canadian gas local distribution companies ("LDCs"). The reviews were prepared by LSM Consulting. These comparisons demonstrate that BC Gas performs efficiently relative to the other Canadian gas LDCs. See Tables C, D and E below.

Overall, the LSM Consulting data shows that on key measures, BC Gas ranks well relative to comparable utilities in Canada. The evidence indicates that PBR has achieved its intended goal for BC Gas, namely, incenting behaviour and activities that reduce the cost of service.

In terms of operating costs and customers/employee, BC Gas ranks favourably against other Canadian LDCs (Tables C and D).

In term of a capital measure, BC Gas places favourably as its costs are below the average in terms of net investment per customer.

TABLE C
O&M Per Customer

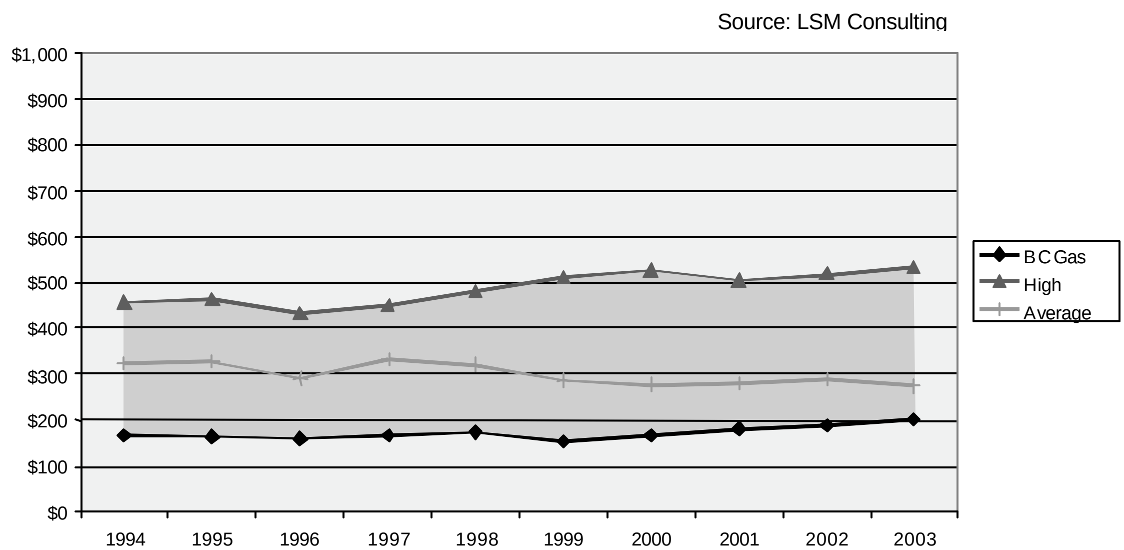


Table C provides a comparison of BC Gas relative to other Canadian gas utilities in terms of O&M per customer. The graph shows that BC Gas has the lowest O&M cost per customer relative to the peer group.

TABLE D
Customers per Employee

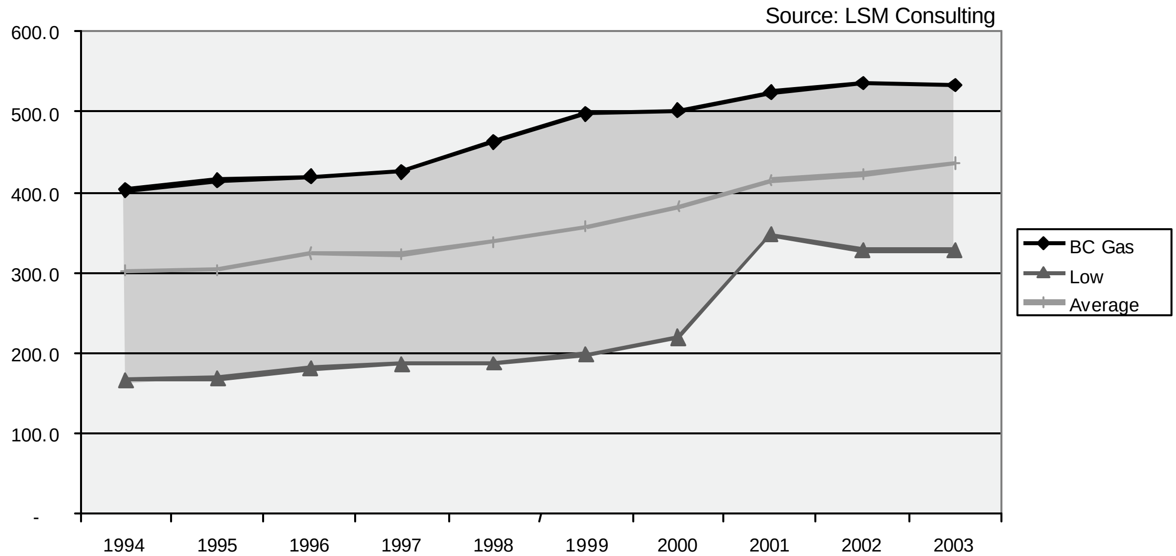
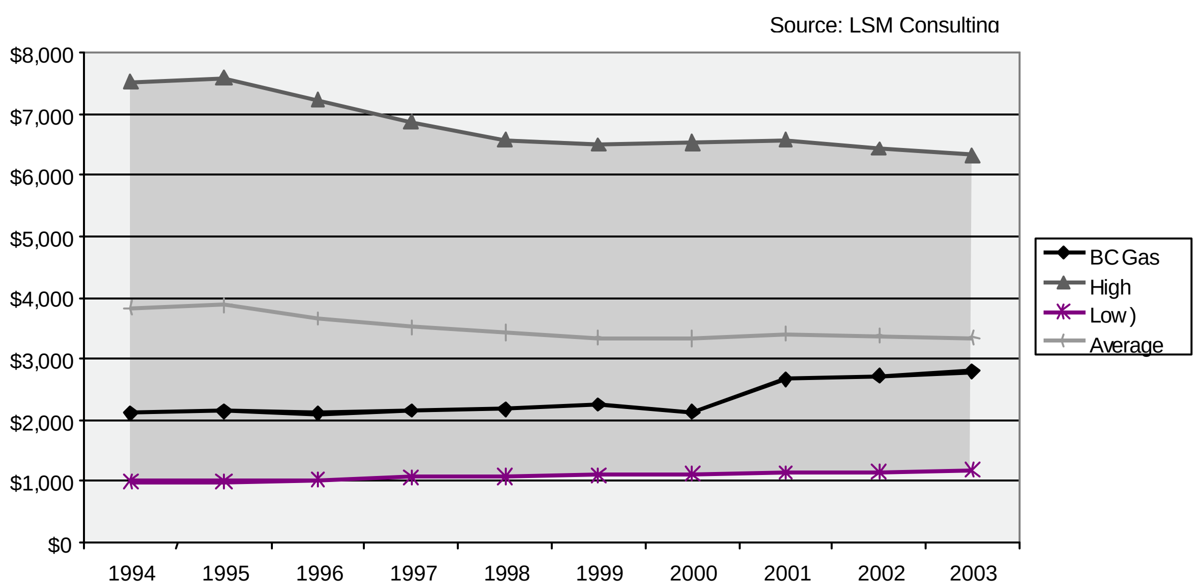


Table E below indicates that while BC Gas capital costs are reasonable, capital would appear to be a better opportunity for achieving gains than O&M going forward.

TABLE E
Net Plant Investment per Customer



3. PERFORMANCE BASED RATEMAKING

BC Gas has operated under various forms of PBR since 1994. These plans have delivered significant value to customers by aligning customer and Company interests through incentives. In this Application, BC Gas is proposing that an expanded PBR Plan that is more comprehensive be established to continue the progress achieved to date.

BC Gas finds itself in an environment that is undergoing considerable change. Natural gas commodity prices have been volatile having risen to unprecedented levels. The general economic circumstances of the service area remain uncertain. Forecast industrial revenues are stagnant. The price advantage of natural gas service against electricity has deteriorated considerably.

Over the next five years, the Company foresees continued pressure arising from governmental or regulatory agencies for higher standards and practices, and other cost pressures, in the areas of:

- environment,
- public and worker safety;
- higher costs related to operating and managing an ageing infrastructure;
- higher costs related to employee demographics;
- additional costs to address higher levels of risk and insurance;
- greater expectations of customers;
- greater costs of maintenance,
- relocation and replacement of capital; and
- the need for a quicker recovery of investment in plant.

In this environment, BC Gas believes it is in the mutual interest of the Company and its customers to expand the latest PBR plan under which BC Gas has operated to a more comprehensive rate setting mechanism. BC Gas is proposing that the applied-for 2003 rates be used as the base year rates for a multi-year PBR mechanism. BC Gas believes that this Application provides sufficient information for parties to proceed with discussions for the regulatory model to be applied to BC Gas for 2003 and beyond.

Since 1994, BC Gas, its customers, and the Commission have advanced the regulatory model for BC Gas beyond traditional year to year cost reviews. Several PBR Plans have been settled through negotiation and have led to gains for all parties. The latest Plan expired at the end of 2001 and rates in 2002 have remained at 2001 levels as a result of the withdrawal by BC Gas of its 2002 Revenue Requirement Application.

In November 2002, the Commission directed "BC Gas to provide its Revenue Requirements Application for 2003 with sufficient information on a stand-alone basis to establish base year revenue requirements for a multi-year PBR setting". Pursuant to this direction, the Company has filed this Application and seeks Commission approval for a process to negotiate with its stakeholders a more comprehensive multi-year PBR mechanism.

A regulatory model is required for 2003 and into the future that provides an effective framework for BC Gas to manage the challenges it foresees and to ensure that customers continue to receive safe and reliable service at stable, reasonable rates.

In this regard, BC Gas had meetings involving stakeholders, regulatory consultants and Commission Staff over the past 24 months to explore views on potential regulatory models. Options range from traditional cost-based regulation, to targeted performance based regulation similar to the model applied to BC Gas in 1997-2001, to a comprehensive price-based mode of regulation.

There appears to be general consensus that properly structured incentive-based regulation can yield superior results to traditional cost-based regulation. A PBR primarily targeting O&M (the focus of the 1998 – 2001 PBR Plan), while effective, has limitations. Targeted PBR relates more to the costs of the utility, as opposed to the rates and outcome to the customer. However, given the uncertainty and challenges anticipated for BC Gas over the next five years, a regulatory model which focuses more on outputs like price and quality of service to customers rather than costs to the utility will be more effective in meeting future challenges. The BC Gas proposal is discussed below.

Proposed PBR Mechanism (DRSM)

The PBR mechanism proposed by BC Gas in this Application moves away from a focus on costs towards a greater focus on customer outcomes, rates and quality of service. The proposed PBR model, referred to as the Delivery Rate Setting Mechanism (DRSM), relates customers' delivery rates to changes in the Consumer Price Index (B.C.) and decouples rates from costs to a greater degree than previous PBR plans. This is a more comprehensive and customer-focused model because it addresses customers' requirements for more predictable and stable delivery rates with quality service. The proposed model is discussed in Section G of this Application. Usual adjustments for items such as changes in taxes and charges arising from legislative or regulatory changes will continue. The Gas Cost Reconciliation Account and RSAM will also continue. However, under this proposed mechanism, customers will be insulated from delivery cost changes to an unprecedented degree. For example, under the DRSM customers would not be exposed to rate revisions for changes in items such as interest rates, rates of return on common equity, reductions in industrial revenues, reductions in customer additions, and variances in capital expenditures and operating expenses.

The proposed DRSM transfers greater risk and accountability to the Company for maintaining or increasing revenues, achieving cost reductions and managing capital spending than would be the case under a targeted PBR model. Customers achieve stable, predictable delivery rates and the Company is provided an opportunity to earn incentive earnings by achieving additional revenues and greater efficiencies.

Service Quality Indicators

A concern under PBR is that service quality could deteriorate as efficiencies are achieved. Therefore, the DRSM proposal includes an expanded set of service quality assurance measures ("Service Quality Indicators" or "SQIs") to ensure that service quality standards are maintained throughout the term of the PBR. These SQIs are more comprehensive and customer focused than those previously used by BC Gas.

Flexibility and Term

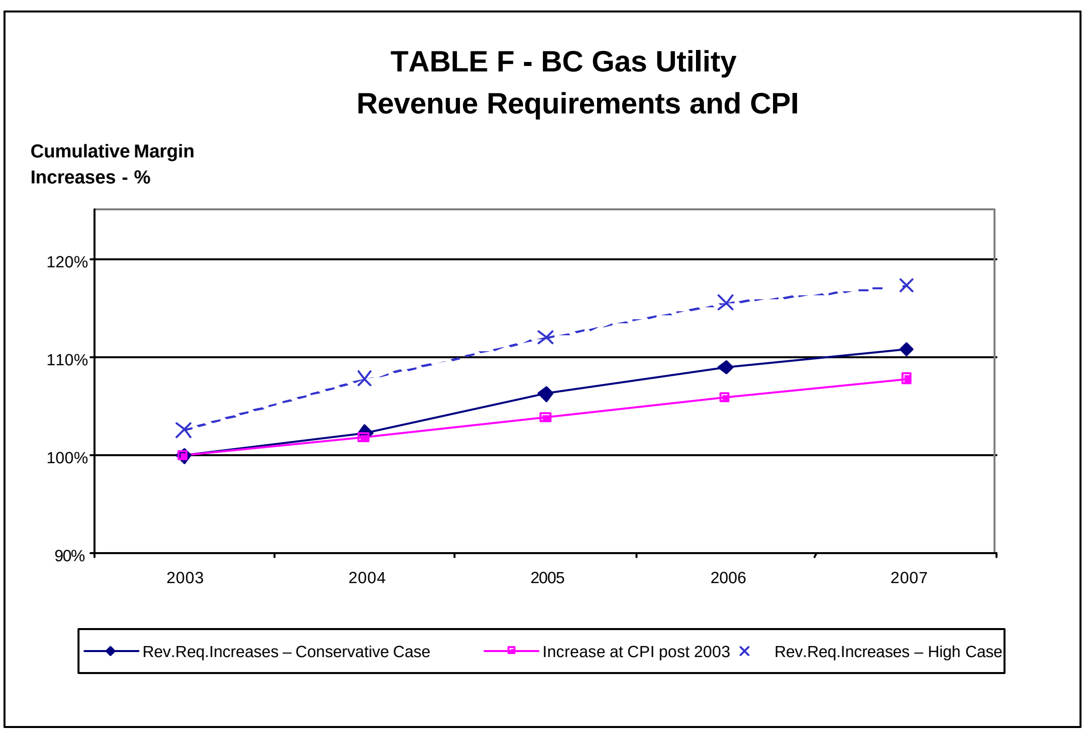
In order to be able to achieve increased efficiencies, BC Gas requires greater flexibility in the manner it operates its business. As part of the DRSM, BC Gas has proposed changes to provide greater freedom in the area of revenue generation, input optimization, tariff flexibility as well as the flexibility to provide new non-discriminatory products and services to customers.

Combined with the longer PBR period proposed (five years versus the two and three year terms of the past), BC Gas should be able to achieve sufficient economic payback for new initiatives to provide benefits to customers, maintain and enhance service quality, and continue to be a viable business in British Columbia.

Five Year Forecast

To provide an illustration of the benefit of the DRSM, BC Gas has forecast potential revenue requirement impacts to customers for the period 2003 – 2007 under a traditional cost of service type of regulation. The chart below shows a range of impacts between a conservative case and a high case.

The solid line represents the projected costs of the Company from 2003-2007 based on conservative assumptions. The dashed lined represents a high case for the costs of the Company for the same period. The elements which form the high case include reduced revenues from the industrial sector, and higher interest rates, authorized rates of return on equity, capital expenditures, depreciation and operating costs than projected in the conservative case. It is difficult to predict with precision what the Company's revenue requirements will be over the next five years. Such a prediction is especially difficult in view of the uncertainty regarding the various cost pressures facing BC Gas. The chart compares a reasonable range of revenue requirement forecasts versus projected CPI increases. A DRSM based on CPI would transfer the risk of potential future cost increases to the Company and should be preferable to customers.



Customer Assistance Fund

As part of the BC Gas DRSM, the Company proposes to create a fund to assist the most needy of its customers to assist in the payment of their gas bill. BC Gas shareholders intend to establish this fund by way of a one-time contribution of approximately $2 million. The fund would assist customers with dealing with potential gas rate volatility. It should be noted that this fund would NOT be funded in customer rates; rather, it would be funded by the shareholders of the Company for its customers.

This fund would demonstrate an "up-front" commitment by the Company of benefit of a comprehensive multi-year PBR. It is the delivery of a tangible outcome for customers that would not otherwise arise. Notwithstanding the Company's assumption of greater risk under the DRSM, BC Gas believes that over a longer term, value can be generated that could support initiatives such as this. It reinforces the view that greater alignment can be achieved between the Company and customers through a more comprehensive PBR Plan.

4. TARIFF CHANGES

In this Application BC Gas submits proposals for changes to its Tariff. There are three main drivers of the proposed changes. First, the changing expectations and needs of customers result in the requirement for certain service enhancements. Second, certain BC Gas business practices require revision to respond to changes in the natural gas industry. Third, there is an ongoing need to clarify the rights and obligations set out in the Tariff. The changes are primarily focused on industrial and transportation service. As a result of these prospective changes, BC Gas believes that there will be an overall increase in the quality of service provision and BC Gas and its customers will have greater clarity with regard to their rights and obligations.

5. PROCESS

BC Gas believes that the optimal result for customers and the Company can only be achieved through a process that allows for the full and frank exchange of views and ideas. This cannot be achieved through the traditional quasi-judicial trial process. Rather, the negotiated settlement processes do. BC Gas seeks a negotiated process for the determination of its 2003 revenue requirement application in conjunction with a negotiated process for a multi-year PBR, that upon agreement will receive approval of the Commission.

6. CONCLUSION

The revenue requirement of BC Gas reflects the significant productivity gains achieved to date and the Company's continuing efforts to control cost pressures. BC Gas is an efficient and well-managed utility. Notwithstanding high productivity targets and challenges faced by BC Gas, the Company has continued its commitment to provide quality service in a safe and reliable manner. This Application also sets out a proposal to expand the PBR plan under which the Company has operated to a more comprehensive multi-year PBR model. This will result in continued effective performance into the future.

BC Gas seeks Commission approval for a negotiated settlement process to determine the 2003 revenue requirement as well as the multi-year PBR mechanism.

This Application together with the development of a longer-term comprehensive regulatory plan provides for the continuation and enhancement of value to customers and the Company.

A. APPLICATION OVERVIEW

1. INTRODUCTION

BC Gas Utility Ltd. ("BC Gas" or "the Company") is seeking an increase in its rates for delivery service of 1.25% on total revenues, effective January 1, 2003. This increase is required to ensure that the Company's revenues recover the costs of serving customers. This Application includes a detailed discussion of the components influencing the need for a revenue requirement increase for 2003.

In support of this Application, BC Gas has provided reviews of the business drivers, capital expenditures and operating and maintenance requirements of the Company for 2003, and its performance on key measures since 1998. This information shows that BC Gas has maintained its high standard of providing safe, reliable, and efficient service to customers.

BC Gas believes that the traditional cost of service method of regulation does not provide the best regulatory framework for the continued alignment of interest between the customers and the Company. BC Gas proposes an expansion of the regulatory methodology that it believes is more appropriate for the environment the Company is facing.

In addition, the Company seeks the British Columbia Utilities Commission (the "BCUC" or the "Commission") approval of a negotiated settlement process to determine its 2003 rates in conjunction with a negotiated settlement process to establish a comprehensive multi-year performance based rate plan for 2003 to 2007.

This Section also provides background of the Company's operations and organization structure. A summary of the total 2003 revenue requirements is included with a review of various comparative analyses.

Forecast natural gas sales and transportation volumes for the five-year period from 2003 to 2007 are discussed in Section B. A review of the energy forecast methodology as well as factors influencing customer additions and use per customer is also included.

Capital expenditures of BC Gas are outlined in Section C, including both regular capital expenditures and projects approved pursuant to Certificates of Public Convenience and Necessity.

Operating and maintenance requirements of BC Gas, broken down by business unit, for 2003 and forecast for 2004 to 2007 are in Section D.

An explanation of Company's accounting, finance and tax issues are provided in Section E and Tariff changes proposed by BC Gas as part of this Application are discussed in Section F.

Section G contains the multi-year PBR proposal that BC Gas believes is the most appropriate for the environment the Company is facing.

Financial Schedules supporting the application are provided in Section H.

2. BC GAS BACKGROUND

BC Gas is one of the largest natural gas distribution companies in Canada, based on the number of customers and service area. Predecessor companies have delivered manufactured gas since the 1800s and natural gas in British Columbia since the late 1950s. BC Gas is an investor owned utility through its parent company BC Gas Inc. and raises capital in Canadian capital markets. This year marks the 50th Anniversary of the incorporation of the predecessor of BC Gas Inc., Inland Natural Gas Co. Ltd.

BC Gas transmits and distributes natural gas through approximately 37,000 kilometres of pipe to more than 765,000 residential, commercial and industrial customers in over 100 communities. These customers represent approximately 90% of the existing natural gas users in British Columbia. The Company's service area is one of the largest in North America. Operations in the Lower Mainland consist of natural gas distribution systems serving the greater Vancouver area, the Fraser Valley and Squamish (through Squamish Gas Co. Ltd.), a main transmission line that connects near Huntingdon with the facilities of Duke Energy Gas Transmission Canada ("Duke") (formerly Westcoast Energy Inc.) and Northwest Pipeline Corporation, and branch lines throughout this service area. BC Gas' transmission system also supplies natural gas to B.C. Hydro's Burrard Thermal plant, and to Centra Gas British Columbia Inc. ("Centra BC") for delivery to Squamish Gas and to Vancouver Island.

Operations in the Inland service area consist of natural gas distribution systems and a transmission pipeline system with a connection to Duke's transmission line at Savona and Kingsvale and a connection to TransCanada PipeLines' (B.C.) pipeline in the vicinity of Yahk. A major new 300-km pipeline, the Southern Crossing Pipeline, was completed in 2000 to increase transmission capacity between Yahk and Oliver. The Inland service area also includes a propane distribution system in Revelstoke. Operations in the Columbia service area consist of a natural gas distribution system with seven transmission laterals running from the transmission line of TransCanada PipeLines (B.C.) to the municipalities served in this region. Operations in the Fort Nelson service area consist of a transmission lateral from the nearby Duke processing plant to the town of Fort Nelson together with a gas distribution system. Customers' rates in the Fort Nelson service area are not affected by this Application.

BC Gas is responsible for the procurement and supply of natural gas to the majority of its customers. The Company purchases its supply of gas from a portfolio of producers, aggregators, and marketers. BC Gas currently utilizes its peak shaving facilities as well as various gas storage facilities under contract to manage its baseload supply contracts and reduce the cost of delivering gas during winter months when the demand is highest, and to balance daily supply and demand. Another key means of mitigating gas cost is to assign pipeline capacity and sell excess supply on an off-system basis. From 1997 to 2001, the total benefits to customers from this activity have exceeded $390 million.

The gas supply, transmission and distribution functions of BC Gas are underpinned by activities that are integral to the safe, reliable and efficient running of its utility operations. Beyond such front line activities as responding to emergencies, constructing, installing, and operating the transmission and distribution system, there are a number of key support functions. They include planning and designing facilities, rights of way acquisition and maintenance, corrosion control, metering, meter reading, leak surveying, and materials management and distribution.

Of equal importance are the systems and services that allow BC Gas to meet its responsibilities effectively in today's dynamic business environment. These supporting systems include customer billing and customer care, work dispatch, marketing, information technology, municipal, community and aboriginal relations, legal, risk management, environment, health and safety, regulatory, human resources, and finance/accounting.

3. RECENT EVENTS

Several events of note which have recently occurred are:

- the reorganization of BC Gas Utility;

- establishing the new operations centre in Surrey;
- the outsourcing of customer billing and customer care services and disposition of related assets to CustomerWorks L.P.;
- the acquisition of Centra BC and Centra Gas Whistler Inc. ("Centra Whistler") by BC Gas Inc; and
- security concerns arising from the events of September 11, 2001.

a. Utility Organization

In January 2002 the Company reorganized its structure to provide greater focus to the operation of the utility. John Reid continues as Chief Executive Officer of the Utility. Milt Woensdregt, Chief Financial Officer, Mary Bruce, Senior Vice President of Human Resources and Randy Jespersen continues to report to Mr. Reid. Mr. Jespersen was appointed as President. Reporting to the President are Jan Marston, Ron Jupp, Doug Stout, David Zerr, David Masuhara, Bob Samels, and Scott Thomson.

From an operating perspective, the Company is structured around three primary lines of business: Distribution, Gas Supply and Transmission. This organization was established to ensure accountability of performance of these business lines and represents a significant change from the past functionally organized structure. This new structure provides greater internal clarity and accountability. In addition to these lines of business, the resources in the Company are managed by functional departments.

b. New Operations Centre

After several years of planning facilities for employees who had been moved from a seismically unstable building located at the Company's Burnaby Lochburn site and from facilities which did not conform to municipal health and safety codes, the Company, with Commission approval, constructed and occupied facilities at its Surrey Fraser Valley and Burnaby Lochburn sites. These facilities have permitted the Company to consolidate a staff of 617 employees largely into one main operating centre in Surrey. This facility has been constructed to post disaster standards to provide continued support of operations during an emergency. BC Gas transferred approximately 430 employees from its offices located at 1111 West Georgia Street, Vancouver. This has allowed the Company to reduce its space requirements in downtown Vancouver from 150,000 sq.ft. in 1998 to 57,900 sq.ft. in 2002. This has exceeded the project business case that was reviewed by the Commission.

Further, the Company financed the Surrey facility fully with debt and forewent a return on equity. This provides customers with a benefit of approximately $1.5 million per year.

c. Customer Care Outsourcing

Customer care services include call handling (customer contact), billing, metering, payment processing and credit and collections. The outsourcing of these customer care services and the disposition of related assets to CustomerWorks L.P. were considered the best solution to address the aged and inflexible customer information systems in use. The key benefits to customers are reduced risk, lower cost of service and improved service levels. A consequence of the outsourcing was the transfer of 125 employees from the utility to CustomerWorks. Additionally, BC Gas will avoid a significant on-going investment in maintaining and upgrading the customer care system technologies.

The transaction was approved by the Commission by Order No. G-29-02.

The Company provides a variety of services to CustomerWorks in the areas such as human resources, enterprise resource planning; risk management, internal audit, facilities management, technology support, and accounts payable. These services are contracted for differing terms ranging from 6 months to 5 years and total $3.2 million annually. While CustomerWorks can terminate these services there is no reflection of the potential loss of these revenues reflected in the Application.

d. Centra Acquisition

The acquisition of Centra BC and Centra Whistler has allowed synergies to arise, and as well may potentially lead to future integration of regulatory elements. Savings between BC Gas Utility and Centra have been identified and reflected in this filing. The savings are in the following areas:

- Corporate Services: treasury, human resources, legal, internal audit, communications, IT governance, environmental, health & safety;
- Gas Control & SCADA; and
- Core Market Administration.

Similarly, savings accruing to Centra will be included in its revenue requirement filing later this year.

Centra presents various challenges. The cost to deliver gas to customers continues to exceed the revenues with the shortfall met by Provincial support for gas supply costs and a deferral account for the residual shortfall. This Application treats Centra as a separate legal entity. However, in the future, opportunities or necessity could dictate a revised review.

e. September 11, 2001

The events of September 11, 2001 resulted in enormous repercussions globally, including on critical infrastructure organizations such as BC Gas. Two significant impacts on BC Gas include the increase in and loss of certain insurance coverages; and the increased focus on security for utility facilities and systems. In terms of insurance, coverages for events such as war and September 11, 2001 have become extremely costly. Coverage for damages and business interruption are now available only with much higher deductibles or higher cost. BC Gas has elected not to make these expenditures and instead requests in this Application a provision to recover any losses in rates should such events occur.

Operationally, as a result of this event, the Company has focussed much more on security and public safety. Additional costs have been and will be incurred in the future related to this area. It has become necessary to liase with multiple layers of security and emergency preparedness organizations to an extent unanticipated. Corporate protocols and exercises to ensure the Company's capabilities and understand risks have become mandatory.

Various government and regulatory agencies are identifying infrastructure that is critical to the national, provincial and local economy and they are increasing their security and mitigation expectations for these facilities. Current plans for mitigation of the associated risks include the following:

- implementation of tighter access and admission procedures at all key facilities;
- risk and security reviews of critical sites;
- increased communication and awareness of security issues to all staff;
- current and future enhancement of security staffing at various locations;
- improved monitoring of critical sites; and

- improved security for IT systems.

BC Gas continues to monitor and assess security issues to proactively manage areas of risk that are identified. The Company works with industry associations and others to develop and implement guidelines and best practices in security and emergency response. The Company also liases with various governmental agencies such as the RCMP and CSIS.

In addition, the National Energy Board Onshore Pipeline Regulations as well as other resources provides a comprehensive approach to emergency preparedness and response for the Canadian pipeline industry.

The Company is placing a greater emphasis on security issues in support of its objective to provide the delivery of safe, secure and reliable service.

4. 2003 REVENUE REQUIREMENT

BC Gas is applying for a $15.4 million increase in its revenue requirements. This is equivalent to an average of 3.29% increase in the delivery margin portion of rates. The following tables set out the 2003 cost of service components.

BC GAS UTILITY LTD.
2003 REVENUE REQUIREMENT - GROSS MARGIN
($000)

Cost of Service Components		
O&M Expense		$152,013
Leases		6,306
Property Tax		41,213
Depreciation Expense		72,651
Other Revenue [1]		(10,294)
Income Taxes		40,351
Return on Rate Base		180,109
Total Gross Margin Requirement		$482,349
Gross Margin at Existing Rates		$466,984
Rate Increase Required	- Amount	$15,365
	- %	3.29%

Note 1: Other Revenue net of SCP 3rd Party and Centra BC (PCEC) revenues

The revenue requirement increase sought in this Application is based on a review of the forecast needs for 2003. It is consistent with Commission Order G-123-01, which directed BC Gas "to provide its revenue requirement application for 2003 with sufficient information on a stand-alone basis to establish base year revenue requirements for a multi-year PBR rate setting".

The increase requested in this Application applies to rates for transportation service and to the delivery portion of rates for customers to whom BC Gas delivers the natural gas commodity; it does not include the gas commodity component of customer rates, which is the largest component of customers' bills. Gas commodity changes are dealt with separately by the Commission. As well, a change resulting from the Commission's return on equity ("ROE") automatic adjustment mechanism is not reflected, as such a change does not arise until December 2002. The current Commission authorized return on equity for 2002 of 9.13% has been used. The ROE for 2003 arising under the Commission mechanism will be a further adjustment to the rates sought in this Application.

The increase for 2003 is primarily required to offset a shortfall in revenue resulting from the reduced consumption of gas by the Company's residential and commercial customers. The Company's revenues are reduced as customers respond to high gas prices and take advantage of demand side management initiatives, including Company-sponsored conservation programs, to reduce their overall gas bills. In 2000, residential customers consumed an average of 113 gigajoules ("GJ") per year. The recent experience of BC Gas indicates that consumption of residential customers has declined significantly and is in the range of approximately 101 to 104 GJ per year. Consumption by commercial customers has also decreased in a similar manner. Given the significance of this drop in consumption and the uncertainty of its duration, BC Gas is using an average annual consumption of 108 GJ per year by residential customers for the purposes of setting rates in this Application. A similar proportional decrease in annual consumption is included in the forecast consumption by commercial customers. Using a consumption rate of 108 GJ, rather than 101 to 104 GJ, has the effect of reducing the amount of the revenue requirement and the associated rate increase.

Variances from the forecast of annual gas consumption by residential and commercial customers (Rates 1, 2, 3 and 23) are captured in a deferral account referred to as the Revenue Stabilization Adjustment Mechanism (or "RSAM") deferral account. Under the RSAM, if the consumption of gas by the Rate 1, 2, 3 and 23 customers (the "RSAM

Customers”) varies from the consumption levels used to establish rates, then the variance in delivery margin collected by the Company is placed in the RSAM deferral account. This variance is then recovered from, or credited to, RSAM Customers over the next three years by way of “riders” to Rates 1, 2, 3 and 23.

The 1.25% increase in total revenues applied for in this Application is equivalent to a 3.29% increase on the delivery margin portion of rates. Delivery margin is equal to the total revenue less gas commodity costs.

Of the 3.29% increase in delivery margin being sought in this Application, 2.39% relates to the reduction in the forecast consumption of the RSAM Customers. In the absence of this Application, the reduction in delivery margin resulting from the reduction in the consumption by RSAM Customers would be recovered from those customers through the RSAM riders. Accordingly, BC Gas proposes to recover the delivery margin deficiency that is associated with the forecast reduction in the consumption of RSAM Customers directly from those customers. The result is an increase in the delivery margin of RSAM Customers of 3.80% and an increase in the delivery margin of other customers of 0.95%. Since the delivery margin deficiency associated with the forecast reduction in the consumption by RSAM Customers will be recovered from these customers as part of this Application, these customers will have a correspondingly lesser amount recovered from them via RSAM riders. Should the decrease in use be less than projected, RSAM customers will benefit through credits to the RSAM account and riders.

Table 2 below breaks out the proposed increase between RSAM and non-RSAM rate classes.

TABLE 2 - BC GAS UTILITY LTD.
2003 REVENUE REQUIREMENT
ALLOCATION OF RATE INCREASE
($000)

Line No.	Particulars	RSAM Classes: Rates 1, 2, 3 & 23	Rates 4, 5 and 6	Other	Bypass and Special Rates	Total
	(1)	(2)	(3)	(4)	(5)	(6)
1	Gross Margin At Existing Rates	$391,194	$12,932	$38,633	$24,225	$466,984
2						
3	Revenue Deficiency	$3,709	$123	$366	$0	$4,198
4	- Use Rate Change	11,167	0	0	0	11,167
5	Total Revenue Deficiency	$14,876	$123	$366	$0	$15,365
6						
7	Revenue Deficiency as a % of Gross Margin	0.95%	0.95%	0.95%	0.00%	0.90%
8	- Use Rate Change	2.85%	0.00%	0.00%	0.00%	2.39%
9	Rate Increase as a % of Gross Margin	3.80%	0.95%	0.95%	0.00%	3.29%
10						
11	Revenue Deficiency as a % of Total Revenue	0.33%	0.24%	0.91%	0.00%	0.34%
12	- Use Rate Change	1.01%	0.00%	0.00%	0.00%	0.91%
13	Rate Increase as a % of Total Revenue	1.34%	0.24%	0.91%	0.00%	1.25%

While the Company is seeking an increase in delivery rates, it should be noted that even with the increase, average residential bills will be lower than they would have been had consumption remained at pre-2001 levels. When the annual bill for a residential customer based on the 112.8 GJ consumption level approved for calculation of 2002 rates is compared to the average annual bill at the new lower consumption level (108 GJ), and the applied-for rate increase is taken into account, the average annual bill for residential customers is lower by approximately $28.

Capital and operating and maintenance ("O&M") costs are the most significant components of BC Gas' total revenue requirement. During the incentive-based PBR plan under which BC Gas operated for the last four years, BC Gas has achieved significant savings by reducing its O&M costs. BC Gas has reduced its workforce by over 20% since 1997. Although under past PBR Plans the incentives to reduce capital spending were lower than the incentives relating to O&M, BC Gas has taken steps to ensure that capital spending is prioritized so that it is put to its best use and the impact on customers' rates is minimized.

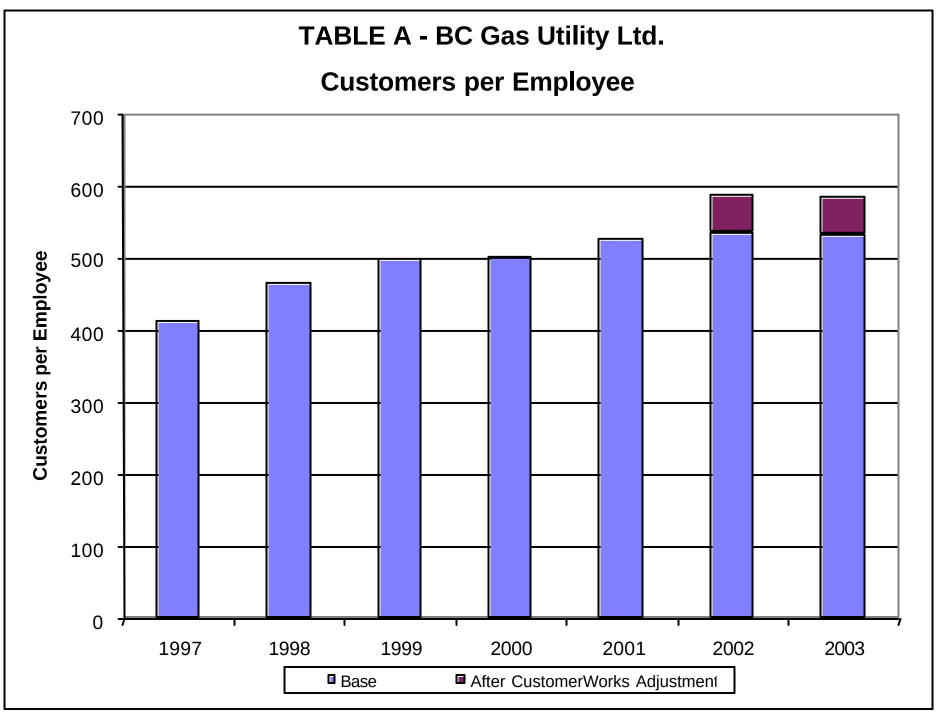
BC Gas believes that the revenue requirement increase requested is prudent and reasonable.

5. COMPARATIVE ANALYSIS

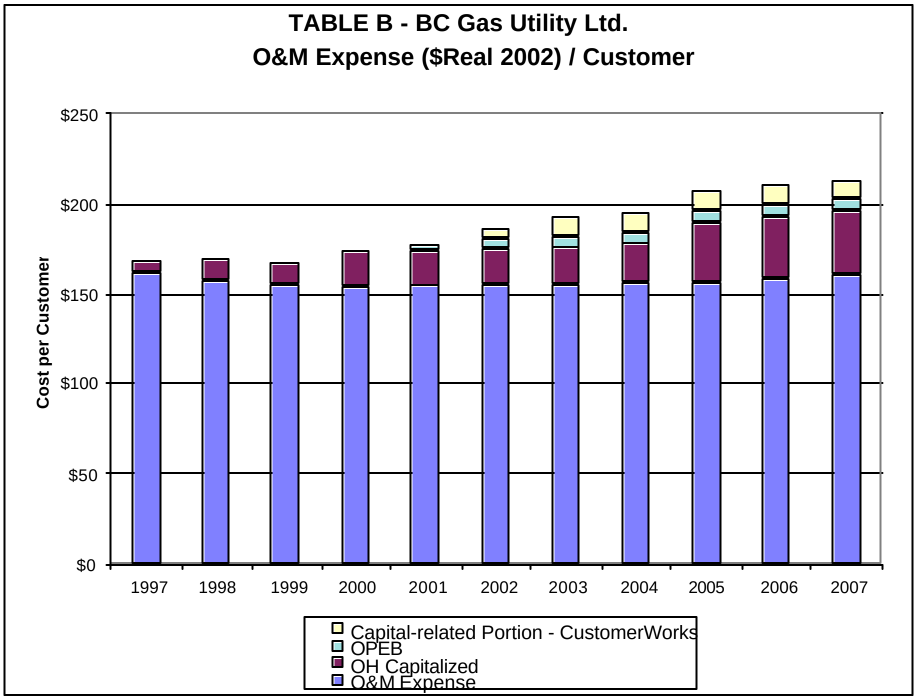
Comparison measures supporting the reasonableness of BC Gas' O&M and capital costs are provided as part of this Application. The results of these studies indicate that BC Gas has performed favourably.

Comparisons provide a way to view Company results over time as well as relative to external groups. Both have been done.

The Company has continuously improved its base operating costs/customer ratios since 1998. One high-level measure of a company's productivity is the number of customers served per employee. As mentioned earlier, the Company has reduced its workforce over 20% since 1997. A high ratio of customers/employee is desirable as long as service levels are maintained. As demonstrated in Table A below, BC Gas customers have been the beneficiaries of continuously improving customer/employee ratios. This has been achieved while service quality levels have been maintained or improved.



In terms of O&M/customer, BC Gas has continued to improve this ratio as can be seen in the table below. After netting out the effect of the overheads capitalization and other accounting changes and the portion of the CustomerWorks charges formerly in BC Gas' rate base, BC Gas has reduced its O&M costs per customer between 1997 and 2002 on a real basis, from $161 to $155 (see the grey shaded area in the table below):



External reviews are also included to provide a comparison of BC Gas' performance relative to Canadian gas local distribution companies ("LDCs"). The reviews were prepared by LSM Consulting. These comparisons demonstrate that BC Gas performs efficiently relative to the other Canadian gas LDCs. See Tables C, D and E below.

Overall, the LSM Consulting data shows that on key measures, BC Gas ranks well relative to comparable utilities in Canada. The evidence indicates that PBR has achieved its intended goal for BC Gas, namely, incenting behaviour and activities that reduce the cost of service.

In terms of operating costs and customers/employee, BC Gas ranks most favourably against other Canadian LDCs (Tables C and D).

In term of a capital measure, BC Gas places favourably as its costs are below the average in terms of net investment per customer.

TABLE C
O&M Per Customer

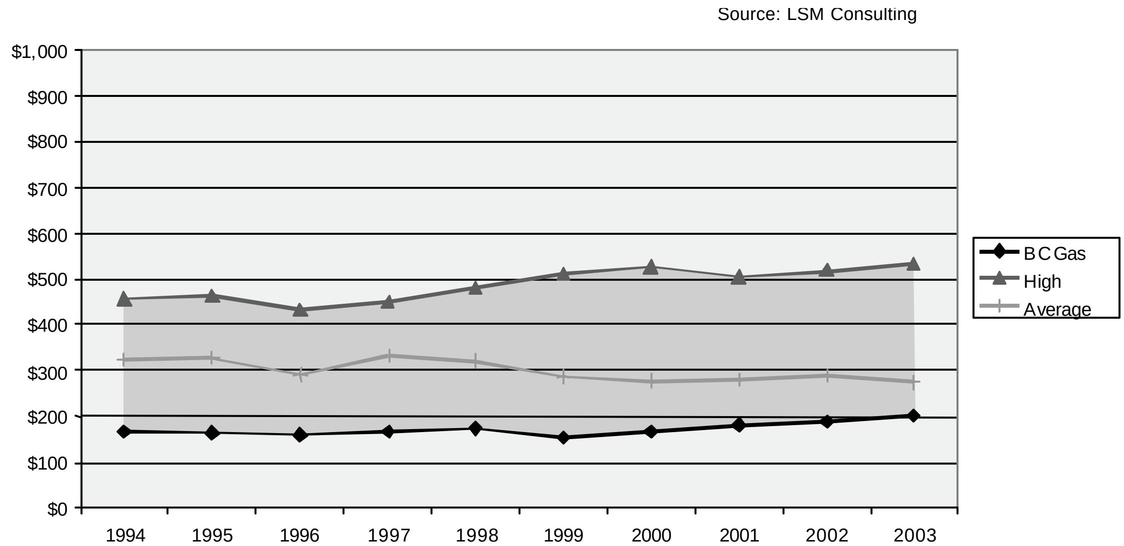


Table C provides a comparison of BC Gas relative to other Canadian gas utilities in terms of O&M per customer. The graph shows that BC Gas has the lowest O&M cost per customer relative to the peer group.

TABLE D
Customers per Employee

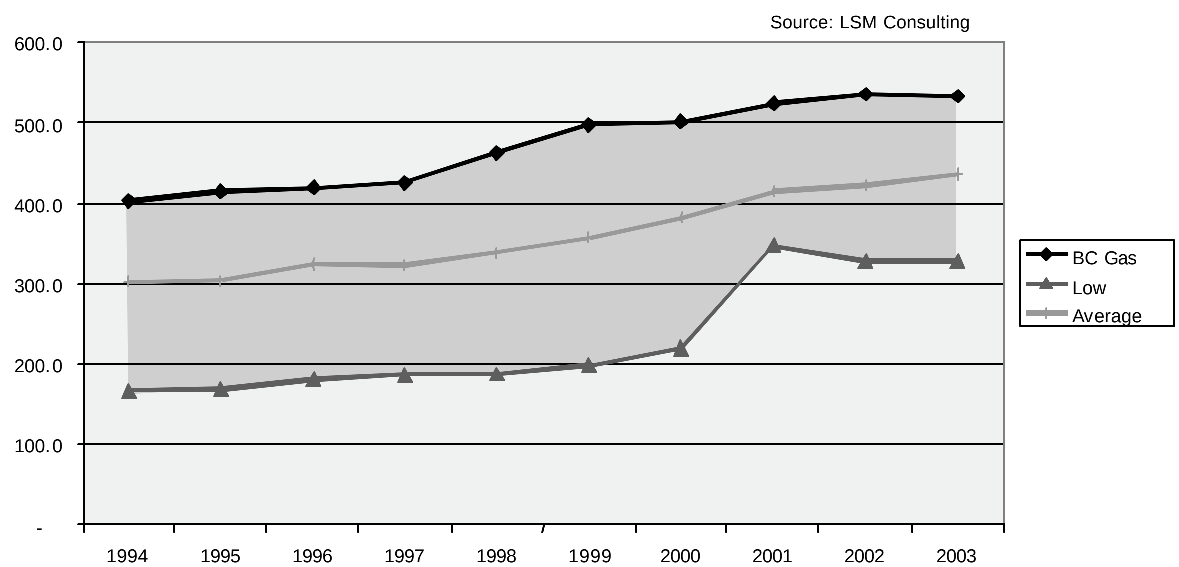
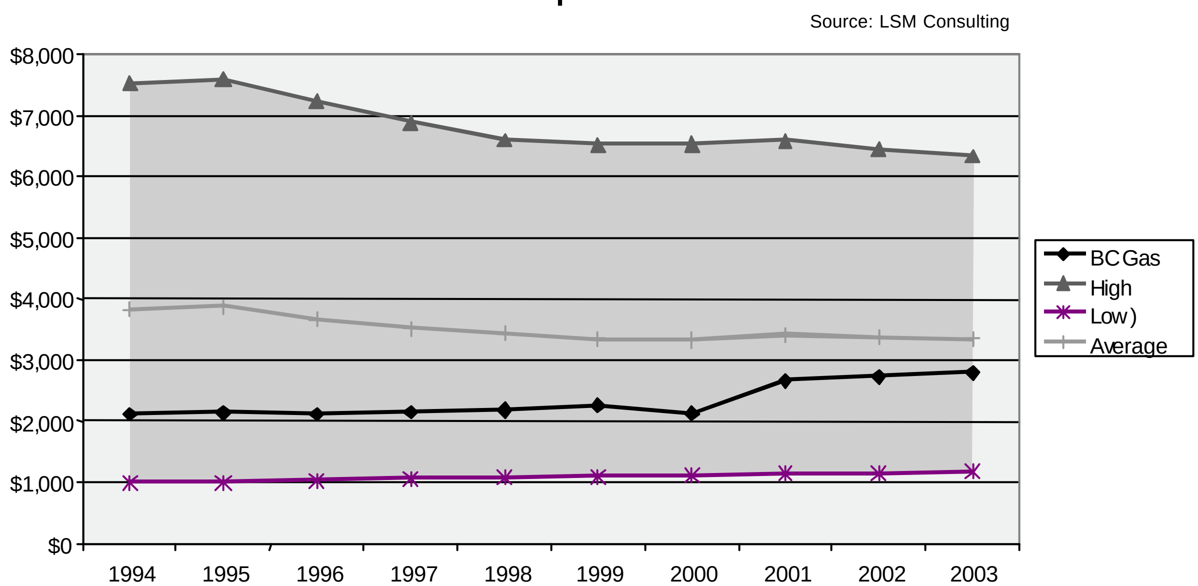


Table E below indicates that while BC Gas capital costs are reasonable, capital would appear to be a better opportunity for achieving gains than O&M going forward.

TABLE E
Net Plant Investment per Customer



6. SERVICE QUALITY INDICATORS ("SQI")

To balance the cost efficiency incentives to the Company, service quality measures were set in the latest PBR plan. Company performance was presented each year to customers in the Commission-sponsored Annual Reviews. As mentioned earlier, the Company has met the established performance levels. The results are set out in the table below.

Projected Year End Results for 2001 Compared to the 2001 Benchmarks

Measures	1997 Actuals	1998 Actuals	1999 Actuals	2000 Actuals	Average for 98/99/00 Benchmark for 2001 "trued up" with 2000 actuals	2001 Projected
1. Response time to emergency calls	19 minutes, 55 seconds	17 minutes, 6 seconds	17 minutes, 12 seconds	17 minutes, 15 seconds	17 minutes, 11 seconds	17 minutes, 50 seconds
2. % of Service Centre calls answered within 30 sec. by a person	76%	85%	84%	84%	84%	84%
3. Leaks per km of distribution mains due to system deterioration	0.0060 (227 leaks)	0.0050 (181 leaks)	0.0036 (131 leaks)	0.0046 (170 leaks)	0.0044 (161 leaks)	0.0042 (156 leaks)
4. Transmission system annual reportable incidents	6	3	0	3	2	2
5. Number of third party distribution system damage incidents per 1,000 housing starts	56.62 (1662 incidents)	73.05 (1456 incidents)	68.00 (1109 incidents)	89.06 (1284 incidents)	76.72 (1283 incidents)	74.19 (1,150 incidents*)

7. CONCLUSION

BC Gas has performed efficiently and effectively during the past five years in delivering value to its customers. Prospectively the Company faces numerous challenges and pressures. The increase sought by the Company reflects rates that are just and reasonable. These rates provide an appropriate basis for negotiation of a multi-year PBR.

B. GAS SALES & TRANSPORTATION VOLUMES FOR 2003 – 2007

This section addresses the forecast of natural gas sales and transportation volumes for the five-year period from 2003 to 2007. Included in the section is a review of the energy forecast methodology as well as factors influencing customer additions and use per customer. The key findings of the analysis include:

- Higher natural gas commodity prices and customer perceptions respecting potential price volatility will continue to drive energy efficiency and the adoption of technology, putting downward pressure on both customer additions and use rate.
- Though they can be expected to decline over the forecast period, it is not possible to accurately project average use rates given the recent shifts in customer behaviour and perception. BC Gas has adopted use rates that reflect the high end of the statistically probable range to help mitigate against any resulting rate increase that could ultimately prove unnecessary.
- Demand growth will be dependent on and driven by a gradual stabilization of the regional economy with measurable economic growth in 2003 and beyond.

A forecast of residential, commercial and industrial revenues and margins for the 2003 to 2007 period is also provided.

1. ENERGY FORECAST METHODOLOGY

The energy forecast is an important component of the revenue requirement application. The customer additions and gas sales forecasts are two of the key drivers of the O&M and capital costs incurred by the Company in serving its customers. The energy and associated revenue forecast are also used to establish the variance between the Company's costs and the revenues collected in current rates. Finally, the energy forecast is used to determine the unit rates for the recovery of the total revenue requirement.

The methodology used in preparing the forecasts for this Application is consistent with the general approach used for revenue requirement applications since 1992 and as has been reviewed by the BCUC and stakeholders at the Company's Annual Reviews conducted under the current PBR Plan. As in prior years, the forecasting process is separated into three main components:

- the customer additions forecast for residential and commercial rate classes
- the average use per customer forecast for residential and commercial rate classes, and
- the industrial rate group forecast.

While BC Gas has typically only prepared shorter-term forecasts for prior applications, this application includes five-year forecasts for each of these items. Recognizing the greater uncertainty inherent in longer term forecasting, BC Gas has also performed additional analyses to estimate a reasonable range of expectations over the five-year period for each forecast component.

The residential and commercial energy forecast incorporates rate classes 1, 2 and 3/23 and is driven by the respective account and customer use-rate forecasts. The industrial rate group's energy forecast includes rate classes 5, 7, 22, 22A, 22B, 22 Bypass, 25, 25 Bypass and 27.

The customer additions forecast reflects macroeconomic factors affecting residential and commercial customer classes – primarily household formation growth. As in prior years, the average use per customer is estimated for Rates 1, 2, and 3/23 then multiplied by the corresponding number of customers in each respective class to derive the energy forecast by rate class. Forecast of Industrial Energy, because of the smaller number of customers in each rate class and the unique characteristics influencing customer additions, relies on sector analyses and customer specific survey results.

2. UNDERLYING ASSUMPTIONS

a. Wholesale Price Of Gas

The 2002-2007 energy forecast for BC Gas is influenced to a significant degree by energy pricing trends. After rising to unprecedented and sustained highs in the winter of 2000/01 natural gas prices have softened, although not to levels experienced prior to 1999. However, notwithstanding the recent price softening, there remains a significant probability that price volatility will recur in this region, though probably not of the magnitude seen during the winter of 2000/01.

The negative demand response to the price shock of 2000/01 may simply have masked the root causes of the regional price disconnection. Economic recovery and renewed demand growth in advance of increased pipeline capacity is expected to produce price increases within the forecast period. Although the timing and magnitude of such increases depend on generally unpredictable market circumstances, price movements are not anticipated to be as severe as those experienced through 2000/01. New pipeline capacity to the region in 2003 and 2004 should help stabilize commodity prices at the Sumas market hub, but is unlikely to provide sufficient certainty regarding energy supply to ensure complete price stabilization to the year 2007. BC Gas' forecast is consistent with an average cost of gas over the five-year period of $4.80 Canadian at Station 2 on the Westcoast Gas Transmission System.

b. Electric Competition

Current energy pricing policy in British Columbia exacerbates the negative impact of higher natural gas prices on BC Gas' energy forecast. While retail natural gas rates, as an energy commodity, reflect market prices, retail electricity rates do not. Government policy based on historic embedded cost sets electricity rates that do not necessarily reflect the incremental cost of each additional unit of supply. As the demand for gas-fired electricity pushes up gas prices, marginal costs might not be reflected in regional electricity. Should this disconnection from marginal cost persist into the future, BC Gas expects the perception of comparatively higher natural gas prices to cause a smaller percentage of new homes and businesses to be served by natural gas. This places downward pressure on the customer addition forecast.

If the provincial energy policy changes to reflect marginal pricing in electricity rates, both the rate of natural gas customer additions and the amount of gas used per customer would likely increase demand for natural gas used in space heating. In the absence of such a change, overall natural gas demand will still rise due to increased demand for gas fired electrical generation. This would result in end-use efficiency losses, greater air emissions, and the continued disadvantaging of natural gas as a primary heating fuel.

According to the Interim Report[1] of the Energy Policy Task Force published November 30, 2001, electricity rates will rise with market pricing. Percentage increases are expected to range between 30 and 60 per cent depending on the customer class.

[1] http://www.em.gov.bc.ca/EnergyPolicytaskforce/InterimReport.pdf

BC Gas' forecast assumes that such electricity price increases will help preserve the relative competitiveness of natural gas as a heating energy source. This should prevent any major additional substitution effect as natural gas prices rise to levels indicated by the forward market.

Increased gas and electricity prices in other regions may also encourage some commercial and industrial customers to curtail operations to sell electricity or gas back to the regional market grid, as was experienced in the winter of 2000/01. Recovery and expansion of energy intensive industries will prove difficult under such circumstances.

c. Changes In Housing Technology

While BC Gas expects customer additions to rebound from record low levels of 2000 and 2001, the growing number of multiple family dwellings in new housing mix, the emergence of heat pumps for detached housing and concerns among new home buyers over higher commodity prices will keep recovery relatively modest.

d. Customer Perceptions Of Natural Gas

While natural gas prices have moderated somewhat from the volatility experienced in the winter of 2000/2001, the natural gas commodity price forward markets signal rising prices over the forecast period. The recent history and forecasts of higher natural gas commodity prices appear to be altering the historic public perception of natural gas as a cheap and plentiful energy source. Further natural gas price increases will likely cause some new homeowners to choose fuels other than natural gas. BC Gas also expects that price-driven investment in energy efficiency measures such as appliance upgrades, setback thermostats, heat pumps, and improved insulation will be accompanied by an increased reliance on electric, oil or wood burning appliances. This will further reduce use per customer and market share in the new home market. Demand side management (DSM) measures also become more attractive during periods of high commodity prices. B.C. Hydro and BC Gas programs to lower energy consumption such as Hot Tips, PowerSmart and H.E.L.P. will be increasingly utilized and have more significant impacts on energy use than in prior years. Over the long term, some of these impacts may diminish if natural gas commodity prices moderate, but gas use is not expected to return to historic levels during the forecast period.

e. Economy

In addition to the changes in the natural gas market itself, regional economic conditions also affect the energy forecast. The BC Gas Forecast assumes a gradual stabilization of the regional economy beginning in late 2002, and signs of recovery through 2003 and beyond. This recovery is assumed to affect most sectors of the economy. Major economic inhibitors (such as the soft wood lumber dispute) are assumed to be resolved relatively early in the forecast period providing a greater degree of certainty and economic optimism.

Any delay in recovery, an increase in the Canadian Dollar versus the US Dollar, or further slackening of the US economy will negatively affect demand for key export commodities produced in British Columbia.

The primary considerations of the BC Gas energy forecast are summarized below:

- The recent stabilization of natural gas prices will be subject to some further price volatility in the future, although not to the degree experienced in 2000/01.
- A gradual increase in regional economic optimism is assumed but with slow growth in 2002 and 2003.
- Energy efficiency will continue to improve through appliance renewal and technological improvement in conjunction with DSM programs.
- Consumers will continue to respond to price changes and any perceived volatility.
- The competitive positioning of gas relative to electricity will gradually improve.
- The housing market will continue to recover.
- Key industrial sectors will experience limited growth and continued technical improvement in energy efficiency.

3. RESIDENTIAL & COMMERCIAL CUSTOMER ADDITIONS FORECAST

The customer addition forecast is derived from both broader regional and provincial economic and detailed end-use information. The inputs are gathered through financial institutions, industrial associations, research institutes, various government agencies and periodic surveys. These provide the basis for a macroeconomic model that relates economic data to account growth.

To forecast residential account additions, actual household formations and historical commodity prices at Sumas are correlated with actual account additions to produce year over year estimates of total account growth on a service area basis. These growth rates are then applied to household formation forecasts to obtain the expected number of additions. BC Gas has used the BC Statistics 2001 Household Formation Forecast to estimate household formations by area for each forecast year. The short-term forecast has also been checked against information on the number of building and development permits and actual service requests.

Commercial account additions are also assumed to correlate with household formation growth projections. Household formation growth projections are applied to account totals from the previous year to calculate the expected number of commercial additions by service area. The factors driving the forecasts are checked for consistency against regional economic trends.

Total net customer additions declined from annual levels in excess of 20,000 in the previous decade to less than 5,000 in 2001. The base outlook for customer additions sees a recovery in residential and commercial sectors through 2003, followed by a period of relatively stable growth in residential account additions with slightly declining growth in commercial account additions.

Although weak economic conditions in British Columbia and slow population growth drove very low numbers for housing starts through 2001, mortgage rate reductions combined with pent-up demand is resulting in some recovery in 2002, which BC Gas expects to continue through 2003 before easing off.

For 2002 BC Gas currently forecasts 7,100 residential additions. Commercial account additions were essentially non-existent in 2001, but are expected to number about 350 in 2002, peaking at less than 500 in 2003. The total number of BC Gas customers is expected to be 769,700 in 2002 and 813,000 by 2007. The table below provides a summary of the customer additions for the last 2 years, a projection for 2002 and the 2003-2007 forecast customer additions. The table also shows the year to year changes in housing starts and population growth.

Total Customer Additions - Rates 1, 2, and 3/23

All Regions	1999 Actuals	2000 Actuals	2001 Actuals	2002 Projected	2003 Forecast	2004 Forecast	2005 Forecast	2006 Forecast	2007 Forecast
Residential Addi	10,009	6,317	4,835	7,100	8,800	8,000	8,100	8,500	8,500
Commercial Add	1,128	823	19	400	500	500	400	300	300
Total Customers	750,229	757,369	762,223	769,700	779,000	787,500	796,000	804,800	813,600
Housing Starts[2]	16,309	14,418	17,234	18,400	20,000	n/a	n/a	n/a	n/a
Population Grow	0.8	0.9	0.8	1.1	1.4	1.4	1.4	1.4	1.5

Notes

1. Year ending customers.
2. CMHC Housing Starts from the February 2002 Housing Now BC Edition.
3. 2001 BC Stats Provincial Population Forecast - Ministry of Finance & Corporate Relations.

4. RESIDENTIAL AND COMMERCIAL USE PER CUSTOMER FORECAST

The energy use per customer forecast for residential and commercial rate classes is derived from actual customer consumption history by rate class. Annual actual usage is normalized for temperature volatility over the most recent 10-year period, and adjustments are calculated for advances in gas appliance and construction technology. Price elasticity and customer choices in housing and building space are also modeled for each year of the forecast period. These adjustment values are then applied to the normalized use rates.

Separate use per account projections are developed for each service area and rate class by considering the following factors:

- the most recent historical normalized use per account;
- customer migration between rates;
- forecast use for new customer additions;
- appliance conversion or replacement effects where applicable; and
- the estimated impact of demand side management programs over the forecast period.

As suggested above, housing choice is one of the factors affecting the use rate per residential account. The historical share of new multiple to single housing units is displayed in the table immediately below.

BC Housing Starts[1]

Year	Multiple Starts	Single Starts	Total BC Housing Starts	% Multiple
1986	7,721	12,966	20,687	37%
1987	12,591	16,353	28,944	44%
1988	12,726	17,761	30,487	42%
1989	17,282	21,612	38,894	44%
1990	18,242	18,478	36,720	50%
1991	13,540	18,335	31,875	42%
1992	19,149	21,472	40,621	47%
1993	25,020	17,787	42,807	58%
1994	22,817	16,591	39,408	58%
1995	15,476	11,581	27,057	57%
1996	15,194	12,447	27,641	55%
1997	16,440	12,911	29,351	56%
1998	11,240	8,691	19,931	56%
1999	7,578	8,731	16,309	46%
2000	6,970	7,448	14,418	48%
2001	9,372	7,862	17,234	54%

Notes

1. Source: CMHC

With the exception of a departure from the trend in 1999-2000, the proportion of multiple to single-family housing has been steadily increasing. This trend is expected to continue over the forecast period in response to changes in lifestyle and shifts in the provincial demographic profile.

It is assumed that customer responses to high gas prices such as lowering thermostat settings and reducing fireplace use will not be as strong in 2002 and 2003 resulting in a marginal recovery in residential and commercial use rates. But over the remaining forecast horizon, the installation of energy-saving equipment like high-efficiency furnaces, advances in construction technology, set back thermostats and improved insulation will place downward pressure on use rates. A change in the overall perception of energy costs will also drive improvements in energy efficiency as well as commodity substitution for some commercial and residential customers.

In this environment, customer demand side response will be significant. BC Gas' DSM programs have been successful. Over 27,000 customers have participated in the Furnace Tune-Up Promotion which is directed towards improving the energy efficiency of the existing stock of furnaces. In addition, almost 1500 customers have taken advantage of BC Gas' High Efficiency Heating System Upgrade Promotion. This program provides incentives for customers to upgrade to high-efficiency furnaces or boilers. The effect of programs such as these will be to permanently reduce the participating customers' use.

A price effect is therefore factored into the forecast use per customer for 2002 and beyond. It is based on an analysis of our weather normalized customer usage over the recent past and of gas industry experience under conditions of price volatility.

Annual use rates for all sectors have shown measurable declines over the past few years. BC Gas expects that the downward trend for use rates will continue, particularly in the face of higher energy cost expectations and continued commodity price increases for natural gas over the forecast period. However, the evidence for the first quarter of 2002 suggests that short-term price effects have peaked, and that some rebound in use rates is likely prior to a return to declining rates through higher efficiency equipment installation.

Notwithstanding the BC Gas expectation that use per customer will trend downward over the forecast period, there is sufficient uncertainty to warrant an upward adjustment in the base year 2003 use-rate and avoid a potentially unnecessary rate impact. Given the magnitude of the price shock in 2000/01, it is as difficult now to accurately predict the use per customer impacts in 2003 as it was in 2001 and 2002. The adjusted use rate assumed by BC Gas is at the high end of the statistically determined probable range, but is still less than that which would result should a user readopt recent historic consumption behaviors. Should BC Gas price and efficiency effects prove accurate, the variance between actual and the forecast use per customer for Rates 1, 2 and 3/23 will be captured in the Revenue Stabilization Account Mechanism (RSAM) and recovered as the account is amortized over the forecast period.

A summary of historic normalized customer usage rates and the forecast use per customer values are shown below. The table also shows the use rate assumptions used to determine rates for 2002, and the adjusted use rates BC Gas has adopted for 2003 through 2007.

Use Rate Forecast 1, 2, 3, 5, & 23

	1997 Normal	**1998** Normal	**1999** Normal	**2000** Normal	**2001** Normal	**2002** Current Rates	**2002** Forecast	**2003-07** Adjusted Forecast	**2003** Forecast	**2004** Forecast	**2005** Forecast	**2006** Forecast	**2007** Forecast
Rate 1	117.3	116.7	116.7	111.7	100.5	112.8	105.0	108.0	104.4	103.8	102.8	101.8	100.7
Rate 2	344.7	339.4	343.7	324.6	305.4	325.7	325.8	324.9	324.4	322.9	319.7	316.5	313.4
Rate 3	4,659.2	3,981.5	4,025.4	3,659.5	3,332.1	3,904.8	3,591.7	3,715.5	3,573.2	3,554.7	3,518.1	3,482.0	3,446.1
Rate 5	19,421.5	17,337.9	17,431.6	15,848.7	13,862.5	12,308.9	12,308.9	Various	12,217.4	12,245.3	12,294.1	12,345.2	12,368.0
Rate 23	6,117.2	6,945.2	6,817.0	6,446.8	5,802.4	7,424.7	5,970.9	6,579.7	5,941.9	5,912.9	5,853.6	5,796.0	5,737.8

5. INDUSTRIAL RATE GROUP FORECAST

The relatively small number of industrial customers favours the use of a survey methodology in order to produce the most reliable forecast for this group. In preparing the industrial energy forecast, BC Gas consulted with customers and analyzed economic data using the September 2001 Industrial Customer Survey results as a base. The survey was updated through a telephone survey of a cross section of customers in February of 2002.

a. Customer Survey

Customer predicted consumption is a key driver for the Industrial Energy Forecast and provides a basic foundation for understanding the industrial energy forecast. Individual customer's plans and actions can have a significant impact on the overall industrial forecast and therefore BC Gas must rely on information obtained from individual industrial customers.

Industrial customers in rates 7, 22, 22A, 22B, 22 Bypass, 25, 25 Bypass and 27 were surveyed for their predicted consumption in the fourth quarter of 2001 asking for a prediction of their consumption for 2002 - 2006. For these customers, their 2007 volumes were set at 2006 levels, which is consistent with customer feedback. An additional telephone survey of 100 customers was conducted in the first quarter of 2002 to address the new economic and political realities. All survey results were analyzed and any uncharacteristic results were investigated. For those customers who did not return a survey, actual consumptions for 2001 were used. Rate 5 customer forecasts were assessed using their normalized 2001 volumes.

The following tables show the results of the two surveys and the combined results. It also summarizes the Industrial Energy Forecast and highlights the contribution the survey information had on the overall forecast.

Industrial Customers Survey Results

	Number of Responses	Response Rate	Total Net Volume (GJs) 2003	2007
2001 Q4 Survey	167.0	30%	36,319,924	35,552,621
2002 Q1 Telephone Survey	77.0	77%	27,138,433	27,369,931
Combined Survey Results	189.0	34%	41,968,426	42,319,903

Eighteen percent of our industrial customers were surveyed representing about 65% of total industrial throughput over the five-year period.

Industrial Customers Survey Results

	Number of Customers	Total Net Volume (GJs) 2003	2007
Industrial Forecast Results (less Burrard)	1,072	64,387,824	66,562,445
Survey as % of Forecast (less Burrard)	18%	65%	64%

b. Sector Analysis

Industry and economic trends were used in the sectoral analysis to assist in forecasting industrial energy. BC Gas' major industrial sectors are: Pulp & Paper, Wood Products, Greenhouses, and Mining. The table below identifies the energy and the percentage each industry represents out of the total industrial forecast. The "Other" category comprises smaller industries such as education, chemicals, commercial buildings, hotels and

Top 4 Energy Consuming Industries

	PJs	%
Pulp & Paper	18.8	29%
Wood Products	8.2	13%
Greenhouses	5.2	8%
Mining	3.4	5%
Other	28.8	45%
Total	**64.4**	**100%**

recreation centres.

Trends in these industries are compared to the surveyed predicted customer consumption. A high, low and base case forecast of overall consumption was determined for each of the major industries, with the total Industrial Energy Forecast being the total of all customers in all industries. Although the Application reflects the base case forecast, the high and low cases are summarized here to provide some background on the sensitivity to the forecast of different, but still reasonable, and arguably just as probable assumptions. In other words, the high and low cases do not represent the extreme best and worst cases.

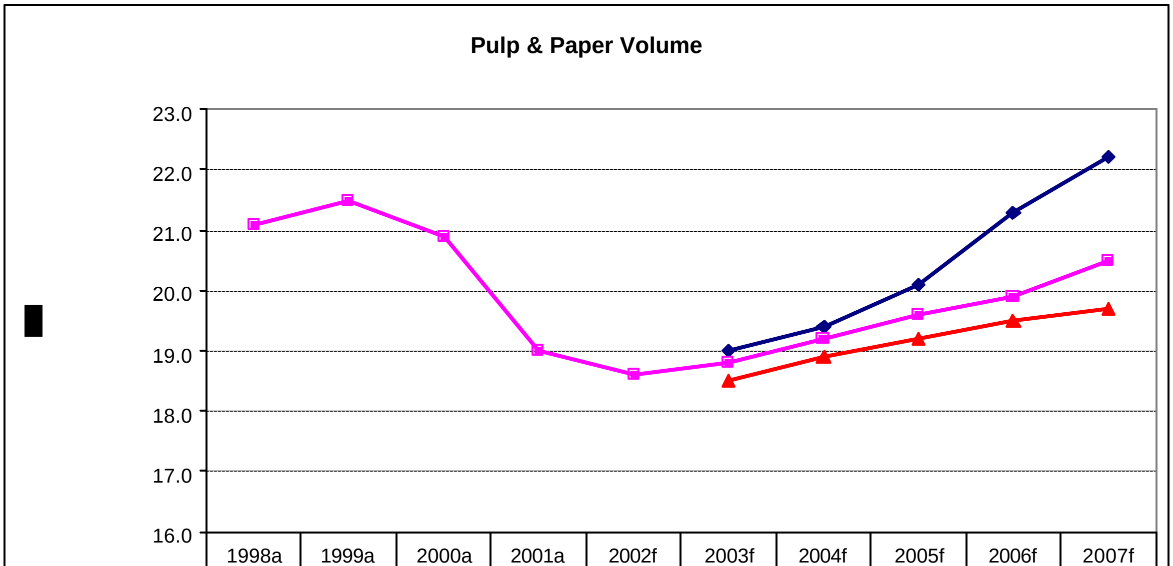
While customer survey information is still the best tool available for to determining future requirements, there was a need to modify survey results to reflect changes in industry expectations since the survey was conducted. For example, the expected impacts of trade issues such as the anti-dumping duty that could have affected hothouse tomato growers and the countervailing and anti-dumping duty that will affect the softwood lumber industry continue to evolve.

i) Pulp and Paper

With only nine customers, Pulp & Paper is still the single largest industrial sector, representing nearly 30% of total industrial volume (excluding Burrard Thermal). The industry has been hard hit in recent years by international market surpluses and resulting low commodity prices for its production. Based on advice provided by industry representatives, the forecast assumes a bottoming out of the downward trend in gas volume, followed by a period of slow stable growth. Overall natural gas volume is expected to grow by about 10% over the forecast period.

The High Case assumes a stronger recovery by the sector, resulting in gas volume increases of about 19% over the forecast period. The Low Case assumes a delay in the recovery of the sector and additional declines in gas use through 2003. The Low Case still results in a 6% increase in gas volume by the sector over the forecast period.

The chart and corresponding table outlines our volumes since 1998 and forecasts through 2007 for the Pulp & Paper industry.



	1998a	1999a	2000a	2001a	2002f	2003f	2004f	2005f	2006f	2007f
High Case						19.0	19.4	20.1	21.3	22.2
Base Case	21.1	21.5	20.9	19.0	18.6	18.8	19.2	19.6	19.9	20.5
Low Case						18.5	18.9	19.2	19.5	19.7

ii) Wood Products

The Wood Products sector represents almost 13% of total industrial volume in BC Gas' franchise regions (excluding Burrard Thermal) with 88 customers. The most significant factor affecting the forecast for the Wood Products sector is the duties imposed by the US government. There will be an average 27.22% duty imposed on Canadian softwood imports into the US, which is comprised of a countervailing and anti-dumping duty.

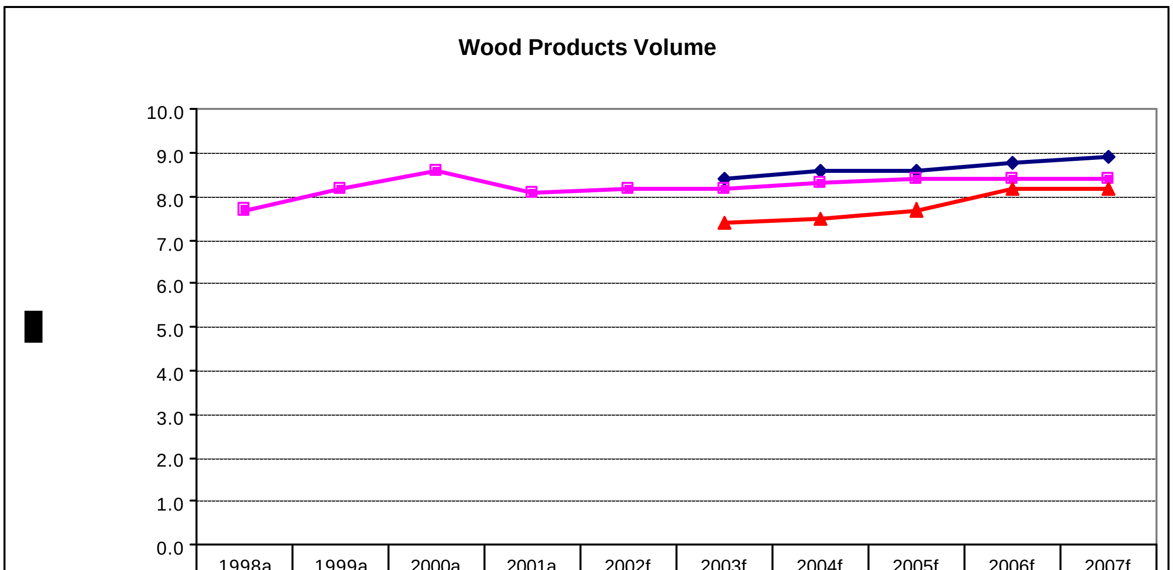
Industry experts agree that the duty will have negative consequences to the lumber industry in British Columbia and Canada. However, it is not known at this time if this will represent a 10% reduction, a 30% reduction or even possibly a 60% reduction to natural gas demand from this industry. It may take more than 6 months after the implementation of this duty before the full effects on natural gas demand deterioration materialize.

The Base Case forecast assumes that a solution to the problem will be found before the end of 2002 and that demand will be relatively flat in 2003 before recovering slowly over the rest of the forecast period. This results in a nearly 2.5% growth in demand by this sector over the entire forecast period.

A High Case was derived assuming that a resolution is reached quickly and that in combination with economic recovery in the U.S., it leads to more demand for wood products and a recovery in the sector. In this case, demand for natural gas by the Wood Products sector could increase nearly 9% over the forecast period.

The Low Case assumes that further demand erosion and industry consolidation is likely and that the dispute with the U.S. is not resolved quickly, leading to further declines in gas volume in 2003, followed by a slow recovery that sees natural gas volumes below 2002 levels even in 2007. However, it is worth noting again that the low case is not a worst case, and for wood products the case has assumed less than a 14% reduction in natural gas demand, relative to the 60% reduction that some industry analysts consider possible.

The following chart and corresponding table outlines our volumes since 1998 and forecasts through 2007 for the Wood Products industry.



	1998a	1999a	2000a	2001a	2002f	2003f	2004f	2005f	2006f	2007f
High Case						8.4	8.6	8.6	8.8	8.9
Base Case	7.7	8.2	8.6	8.1	8.2	8.2	8.3	8.4	8.4	8.4
Low Case						7.4	7.5	7.7	8.2	8.2

iii) Greenhouses

The Greenhouse industry represents about 8% of total industrial volume (excluding Burrard Thermal) with 85 customers.

This industry has grown dramatically over the past 5 years, with a 114% increase in area under glass. In discussions with industry experts, we can expect the greenhouse industry to continue growing, but at a slower pace over the next 5 years. However, within this timeframe it is also expected that greenhouses will implement new technologies and modify existing planting and harvesting techniques that would reduce the industries consumption of natural gas. Some of these strategies include replacing their current boilers with new, more energy efficient boilers, installing heat buffer tanks, using energy screens, using alternative fuels such as wood and landfill gas (methane), adding alternative lighting and more. These energy efficiency measures could result in a reduction of gas use by 10-20% annually.

Although the sector is expecting productivity growth over the forecast period, that growth is not expected to translate into incremental gas demand. In fact, it is forecast that the incorporation of higher efficiency practices and capital will result in declining natural gas requirements for this sector over the forecast period. These plans are attributable in large part to the rapid run up of natural gas commodity prices and volatility in 2000/2001.

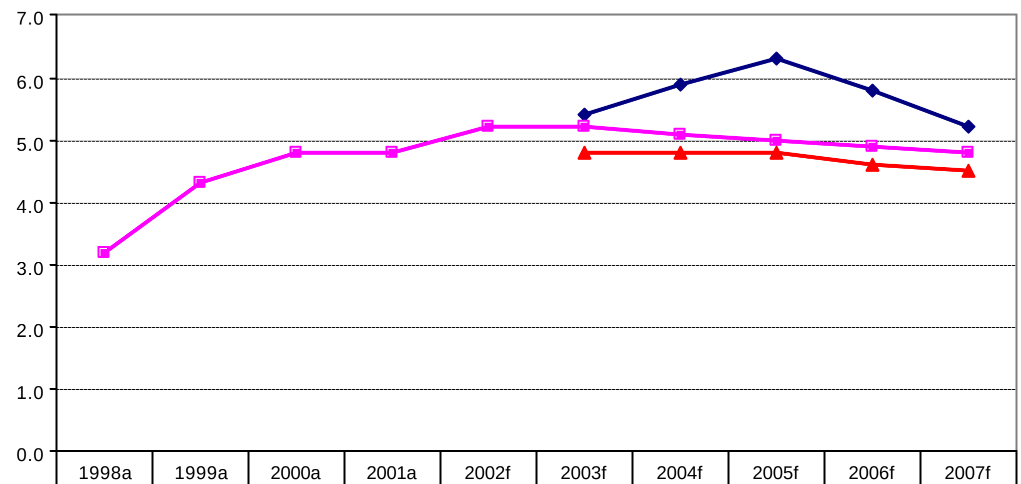
Greenhouses will also see increased competition for exports to US markets. Currently, about 75% of B.C.'s tomatoes, 60% of the peppers and 50% of B.C.'s cucumbers are exported to the US. The main competitor of B.C. greenhouses in the US market is Mexico, where production costs are significantly lower than for B.C. producers. As such, the base case forecast shows a total decrease in volumes of 8% in the forecast period for this sector.

For the High Case it was assumed that the reduced natural gas commodity prices delay efficiency efforts, but that declines due to efficiency then happen quickly in the last two years of the forecast period. It is anticipated that in the event of another natural gas commodity price shock, capital investment and efficiency plans will be implemented quickly, resulting in a rapid and permanent decline in natural gas use by this sector, and by 2007, it is assumed that the consumption levels will be at the same level as the forecast 2002 level.

The Low Case assumes lower productivity, higher natural gas prices and decreased demand for products from the Greenhouse sector. This case also assumes that the implementation of such efficiency measures shall reduce throughput and results in about a 13.5% decrease during the forecast period.

The following chart and corresponding table outlines our volumes since 1998 and forecasts through 2007 for the Greenhouse industry.

Greenhouse Volume



	1998a	1999a	2000a	2001a	2002f	2003f	2004f	2005f	2006f	2007f
High Case						5.4	5.9	6.3	5.8	5.2
Base Case	3.2	4.3	4.8	4.8	5.2	5.2	5.1	5.0	4.9	4.8
Low Case						4.8	4.8	4.8	4.6	4.5

iv) Mining

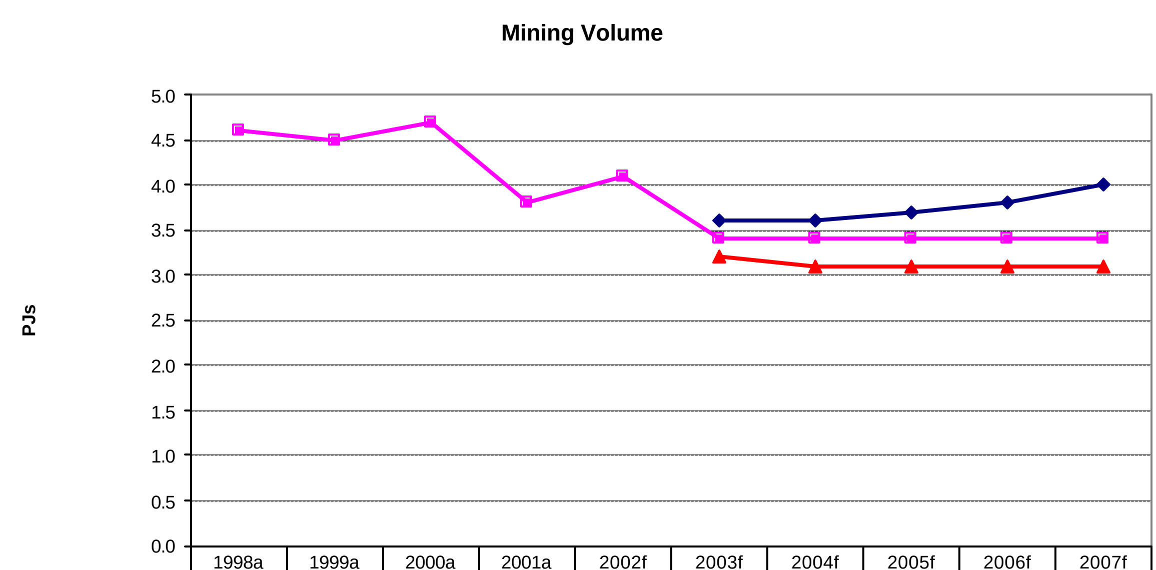
Mining represents about 5% of the overall industrial forecast (excluding Burrard Thermal) with 8 customers, and is the fourth largest industry in terms of energy use.

Although the mining sector has been experiencing a steady decline in British Columbia since 1961, BC Gas' forecast assumes that this decline will bottom out in 2003, followed by an extended period of fairly flat demand for natural gas. A single customer being removed from the system causes the drop from 2002 in 2003.

The High Case assumes some recovery of the mining sector and a resulting increase in natural gas demand. This recovery could happen if the provincial government provides more certainty over access rights to Crown lands. Under this scenario, natural gas demand could recover back to 2002 levels by the end of the forecast period after declining in 2003.

The Low Case assumes further declines for the sector, with even deeper drops in gas volume in 2003 and 2004 before stabilization begins. Over the forecast period, demand for natural gas in this case is forecast to decline 24% between 2002 and 2007.

The following chart and corresponding table outlines volumes since 1998 and forecasts



	1998a	1999a	2000a	2001a	2002f	2003f	2004f	2005f	2006f	2007f
High Case						3.6	3.6	3.7	3.8	4.0
Base Case	4.6	4.5	4.70	3.8	4.1	3.4	3.4	3.4	3.4	3.4
Low Case						3.2	3.1	3.1	3.1	3.1

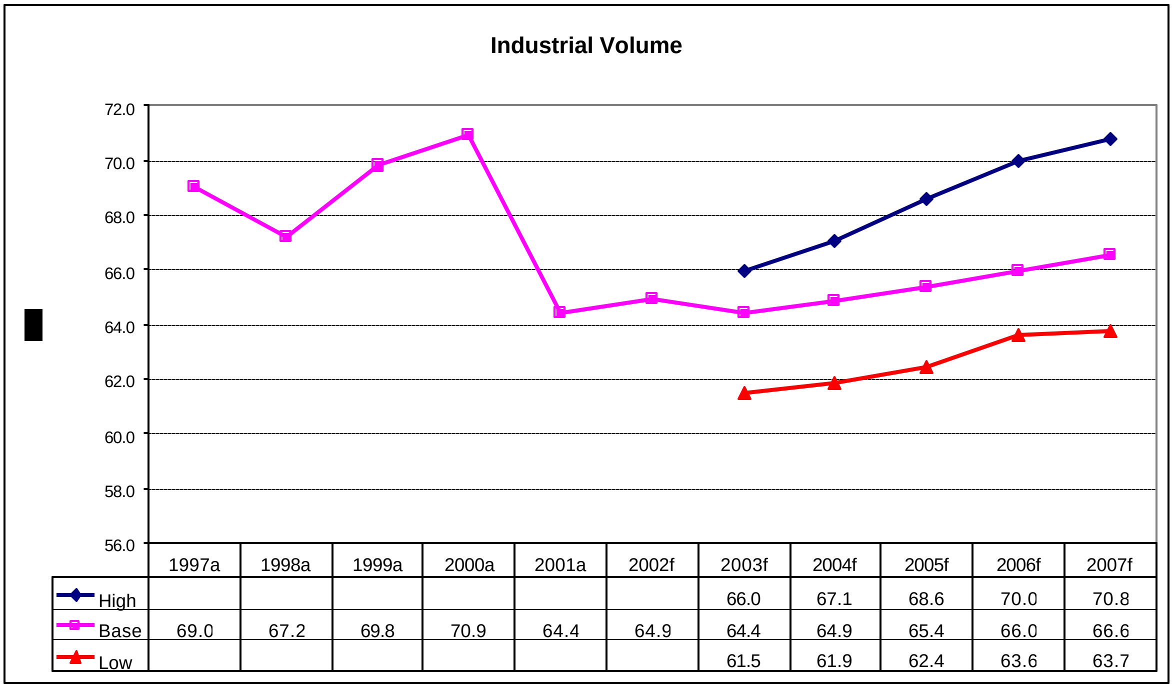
through 2007 for the Mining industry.

v) Industrial Energy Forecast

Over the forecast period, natural gas consumption is forecast to grow by about 2% in the base case. This growth is due to an overall economic recovery, and the factors outlined in the sectoral analysis.

While natural gas usage may increase as energy prices moderate (high case scenario), there is also a reasonable probability that natural gas use may actually decrease (low case scenario).

The chart and corresponding table below outlines industrial volumes (excluding Burrard Thermal) since 1997 and annual forecasts through 2007.



6. ENERGY FORECAST FOR ALL CUSTOMER RATE CLASSES

The following table summarizes the total energy forecast for all customer rate classes using the methodology stated previously and broken down in the following categories: Residential (Rate 1), Commercial (Rate 2 and 3/23), Firm Sales (Rate 4, 5 and 6) and Industrial (Rate 7, 22, 22A, 22B, 25 and 27). The residential and commercial energy forecast is calculated by multiplying the estimated use-rate by the total number of customers including customer additions. A similar methodology is also applied to Rate 5 (Firm Industrial) customers. The industrial forecast was based on the customer survey and the sectoral analysis

The table shows that 2002 consumption is expected to increase slightly from 2001, with slow to moderate growth over the remaining forecast period.

Energy Forecast Summary (PJs)

	1999 Normal	**2000** Normal	**2001** Normal	**2002** Adjusted	**2002** Forecast	**2003** Forecast	**2004** Forecast	**2005** Forecast	**2006** Forecast	**2007** Forecast
Residential	77.8	75.4	68.4	77.5	72.1	75.0	76.0	76.8	77.7	78.6
Commercial	51.5	47.3	43.9	49.0	46.5	47.7	48.0	48.2	48.4	48.6
Firm	9.6	10.9	8.9	6.9	6.9	7.0	7.0	7.1	7.2	7.3
Industrial[1]	61.2	58.9	55.6	58.5	58.5	58.1	58.6	59.1	59.6	60.2
Total	**200.1**	**192.5**	**176.8**	**191.9**	**184.0**	**187.8**	**189.6**	**191.2**	**192.9**	**194.7**

Notes

1. Excludes Burrard Thermal and Centra.

7. REVENUE FORECAST

Revenue forecasts for each customer class were developed from the total energy forecasts and the applicable rates. The revenue forecast does not include amounts for Centra and B.C. Hydro for Burrard Thermal. These revenues are included in the tables of the Application and reflect the existing agreements. The revenue from other by-pass customers is included and is not subject to the downward pressure on usage that is affecting other customers.

The table below summarizes the 2002-2007 revenue forecasts by market segment and provides data from 1999-2001 for comparison purposes. The table also compares the revenue assumptions used to derive 2002 rates with the current forecast for 2002. The table breaks out forecast revenue by Residential (Rate 1), Commercial (Rates 2 and 3/23), and Firm (Rates 4, 5 and 6), Industrial (Rates 7, 22, 22A, 22B, 25 and 27). Burrard and PCEC revenues and margin are not summarized in this section but are shown in Tab 7.

Revenue Forecast Summary ($ millions)

	1999 Normal	**2000** Normal	**2001** Normal	**2002** Adjusted	**2002** Forecast	**2003** Forecast	**2004** Forecast	**2005** Forecast	**2006** Forecast	**2007** Forecast
Residential	493.5	611.0	780.3	744.2	698.5	724.4	733.1	741.5	750.2	759.1
Commercial	268.3	324.7	429.4	392.1	377.7	384.9	387.1	389.0	390.7	392.3
Firm	38.2	60.8	79.8	51.9	51.9	52.2	52.4	53.1	53.7	54.5
Industrial	37.3	37.0	41.5	42.8	42.8	42.3	42.3	42.5	42.7	42.8
Total	**837.3**	**1,033.5**	**1,331.0**	**1,231.0**	**1,170.9**	**1,203.8**	**1,214.9**	**1,226.1**	**1,237.3**	**1,248.7**

8. MARGIN FORECAST

The table below reports the forecast margin information for Residential, Commercial, Firm Sales and Industrial Customer classes, and for comparison provides similar historical information as was provided for revenues above.

Margin Forecast Summary ($ millions)

	1999 Normal	**2000** Normal	**2001** Normal	**2002** Adjusted	**2002** Forecast	**2003** Forecast	**2004** Forecast	**2005** Forecast	**2006** Forecast	**2007** Forecast
Residential	234.8	237.1	250.8	276.3	263.0	271.2	274.5	277.6	280.9	284.2
Commercial	109.0	106.2	112.2	122.2	117.7	120.0	120.6	121.2	121.7	122.2
Firm	13.4	15.7	14.1	12.8	12.7	12.9	13.0	13.2	13.3	13.5
Industrial	33.1	32.5	38.3	41.5	41.5	41.0	41.0	41.2	41.4	41.6
Total	**390.3**	**391.5**	**415.4**	**452.8**	**434.9**	**445.1**	**449.1**	**453.2**	**457.3**	**461.5**

9. OTHER REVENUE

In addition to the residential, commercial and industrial forecasts, BC Gas forecasts Burrard Thermal, Centra Gas and SCP revenues separately.

a. Burrard Thermal

Various Burrard Thermal agreements generate nearly $9.9 million in revenues annually. The transportation charge is fixed and independent of energy consumption. This contract runs through to October 31, 2010.

b. Centra Gas

The Centra Gas transportation agreement generates $3.9 million in revenues annually. This transportation agreement is for a fixed amount and is independent of energy consumption.

c. SCP

SCP Revenue Margin is forecast at $1.3 million for 2002 and then $1 million each year for the remainder of the forecast period. This forecast is based on an assessment of potential mitigation revenues conducted in March 2002, and based on indications from the forward price curves at that time.

During the first year of operation of the SCP, while gas prices and basis differentials were at unprecedented high levels, BC Gas was able to garner $13.2 million in revenue margin by flowing gas on the Duke Energy system (Westcoast) between Station 2 and Huntingdon utilizing capacity that was not being used by SCP shippers. Gas prices and basis differentials have since declined and as a result much lower mitigation potential exists for 2002 and 2003.

In addition BC Gas has negotiated a new transport arrangement on the Duke Energy system starting in the winter of 2003/04 that replaces the SCP related Station 2 to Huntingdon capacity with capacity from Kingsvale to Huntingdon. As a result of the new transport arrangement, the cost of the proposed Duke Energy expansion will be reduced by approximately $70 million and the amount of firm service held by BC Gas will be reduced. These changes result in ongoing annual savings of $5.5 million in firm service tolls. However BC Gas will no longer have the ability to mitigate as much SCP costs by utilizing Station 2 to Huntingdon capacity. There may be some potential to capture mitigation revenue when the

SCP capacity is not being utilized and the basis differentials between Kingsgate and Sumas allow for more than the recovery of variable costs.

Since the conditions that will result in the potential for mitigation revenues are not within the control of the Company, BC Gas proposes that the SCP third party revenue deferral account be continued, such that any future mitigation revenue that is gained via the SCP will flow to BC Gas' customers.

C. CAPITAL REQUIREMENTS

This section discusses the capital expenditures of BC Gas including both regular capital expenditures and projects approved pursuant to Certificates of Public Convenience and Necessity.

Under the provisions of the *Utilities Commission Act* BC Gas has an obligation to serve the requirements of its existing customers and to provide service to new customers within its service area. Continuation of safe and reliable service to BC Gas' customer base of more than 765,000 customers, and providing service to new customers, requires ongoing capital expenditures. While BC Gas takes every effort to minimize the costs of those expenditures, the maintenance and expansion of the Company's facilities requires that substantial new plant be placed in service each year.

The costs associated with the investment in plant and facilities are a significant portion of the revenue requirement of BC Gas. The increase in rates required for 2003 is affected not just by capital expenditures in 2003 but also from capital expenditures that went into service in 2002 and earlier years. Plant going into service in 2003 will affect rates by the cost of capital and income tax associated with the plant being in service for only part of the year. Plant that went into service in 2002 will have the cost of capital and associated taxes based on the plant being in service for the full year 2003 together with depreciation expense for the year. In other words, plant that went into service in 2002 will have a greater impact on the rates paid by customers in 2003 than will plant put into service in 2003. Since there was no adjustment to the delivery margin paid by customers between 2001 and 2002, the revenue requirement set out in this Application is also influenced by the plant that first came into service in 2001. Approximately two-thirds of the Company's revenue requirement (excluding cost of gas) relates to cost associated with capital investments

Capital expenditures of the Company from 1998 to 2001 were made pursuant the Performance Based Rate Plan approved by the Commission under Order G-85-97 which included formulas that set a benchmark for capital spending. For capital expenditures within Categories A and C (as described below) a capital efficiency mechanism was included as part of the 1998 - 2001 PBR Plan. The capital efficiency mechanism rewarded BC Gas if the annual capital expenditures within each of Categories A and C were less than the benchmark, and penalized BC Gas by reducing its earnings if the capital expenditures exceeded the benchmark. In this fashion, discipline was provided to BC Gas to manage capital expenditures in a manner that minimized the amount spent. In November 2001 the Company withdrew its Application to revise rates for 2002. As a consequence rates in 2002 could not change from 2001 levels to reflect costs associated with additional capital projects and financial discipline continued to be provided to BC Gas to minimize its capital expenditures. This Application relates to rates for 2003 (and provides information to be used as a basis for a multi-year PBR) and does not include a capital efficiency mechanism (except as discussed in relation to a multi-year comprehensive rate setting mechanism).

BC Gas has established a Capital Management Office to co-ordinate and evaluate requests for capital funding. Requests are balanced against safety and reliability requirements, and also against the current year's budget, and future years' projections. Projects are prioritized to ensure that capital is put to its best use and the impact on customers rates arising from capital expenditures is minimized.

Capital expenditures during the four years of the 1998 - 2001 PBR Plan act as a guide to the level of ongoing capital requirements of BC Gas. The existence of the capital efficiency mechanism, and scrutiny of the BC Gas capital projects by Commission Staff and interested parties during the Annual Reviews held during the PBR period, acted as a test to ensure that the capital expenditures made were required to maintain and support the existing infrastructure and upgrade that infrastructure as necessary. The capital expenditures during 2002, with the financial discipline on expenditures resulting from delivery rates remaining constant from 2001 to 2002, provides further evidence of the appropriate level of the Company's capital expenditures. The capital expenditures that are forecast to be incurred by BC Gas in 2003 are reasonable and appropriate and consistent with the level of expenditures in prior years. Information regarding the Company's capital expenditures during the 1997 - 2002 period is presented in this section to provide baseline information against which the 2003 capital expenditures can be compared. Information relating to capital expenditures is also in the financial schedules, commencing at page 3, tab 3, section H.

The forecast capital expenditures for 2003 are the appropriate level of expenditure in 2003. Information on the forecast capital expenditures beyond 2003 is also presented in this section as background information for the multi-year PBR discussion. The capital expenditures forecast for the 2004 - 2007 period are a reasonable and conservative estimate of the capital required by BC Gas in that period to provide safe, reliable and efficient service to customers and to meet its obligations under the *Utilities Commission Act*.

1. RECENT AND FORECAST MAJOR PROJECTS

The major projects described below, most of which have been approved by the Commission pursuant to Certificates of Public Convenience and Necessity, have been, or will be, undertaken to provide safe, reliable and efficient service to customers. Those that will be, in part or in whole, in service in 2003 have an effect on the costs of the Company and consequently contribute to the revenue requirement being sought from customers in 2003. Other major projects discussed below will not contribute to the rate increase in 2003 since they will not be in service until later years, but under traditional rate making methodologies would contribute to increases in customers' rates in the future.

a. Transmission Pipeline Integrity Plan (Orders C-15-01 And C-3-02)

A major project included in the Company's capital expenditures is the Transmission Integrity Management Plan ("TPIP") that is currently in progress and planned to run through 2007. The TPIP is part of an overall transmission system integrity management program that the Company developed to protect the public and environment by ensuring that its higher-pressure transmission pipelines provide continued safe and reliable service. The transmission system integrity management program recognizes the ageing components of the BC Gas system (see the tables at page 10 of Section D) and responds to the increased awareness of the public, regulators and BC Gas resulting from a number of pipeline incidents across North America in the past decade.

The major components of the TPIP are retrofits of the existing pipeline systems to allow the passage of In-Line Inspection ("ILI") tools; performing inspections by running ILI tools capable of detecting corrosion, dents and other anomalies; and repair and rehabilitation programs. The program also includes the capital costs associated with developing a corrosion growth model and strategy that drives the inspection and remediation.

The first ILI tools were run in the Interior Transmission System in 1988 and tool runs and/or repair programs have been undertaken each year since that time. During the period from 1988 to 1997 the program was funded through amounts approved in CPCN applications or through the Company's regular capital program. During the period 1998 to 2000, TPIP programs were funded through the Category B capital budget.

The Coastal pipeline system contains restrictive valves and piping which prevent the effective use of ILI tools. In 2000 a decision was made to undertake the work necessary for the efficient use of ILI tools which would then allow a more comprehensive and cost effective means of ensuring the integrity of the Coastal pipeline facilities. Following discussions with BCUC Staff, the Company decided it was appropriate to seek the increased funding requirement through the CPCN process. CPCN applications have been submitted and approved in 2001 and 2002 and similar CPCN applications will be submitted in future years. Each CPCN application covers general program and rehabilitation costs in the year of application and retrofit and tool run costs for the subsequent year.

The table below provides the anticipated TPIP expenditures. Costs for the plan will continue beyond 2007.

Transmission Pipeline Integrity Plan (TPIP) actual and forecast

Annual Capital Expenditures ($ million)

	2001 Actuals	**2002** Projected	**2003** Forecast	**2004** Forecast	**2005** Forecast	**2006** Forecast	**2007** Forecast
Direct Costs	9.2	9.2	9.4	9.1	10.1	4.5	4.5
AFUDC	0.2	0.3	0.3	0.3	0.3	0.2	0.2
Total	**9.4**	**9.5**	**9.7**	**9.4**	**10.4**	**4.7**	**4.7**
Total Real	**9.6**	**9.5**	**9.5**	**9.1**	**9.9**	**4.3**	**4.3**

Note: Real totals in 2002 values.

Expenditures of $9.2 million occurred in 2001 and that amount, plus AFUDC, was included in rate base in 2002. Expenditures of $9.2 million are projected for 2002 and, together with AFUDC, will be included in rate base in 2003.

Forecast expenditures on the TPIP decline in 2006 and 2007 due to the expectation that the majority of piping changes required to allow the passage of ILI tools will be completed. Also, rehabilitation costs will begin to decline towards the end of the forecast period.

The costs for TPIP presented in this Application are on the basis that the TPIP expenditures are treated as capital expenditures (and not treated as operating and maintenance expenses). The TPIP expenditures relate to a comprehensive program to extend the useful life of the transmission system and as such should be recovered over the life of the assets to ensure no intergenerational inequities arise. The TPIP costs include costs of valve replacement and those associated with changing the configuration of portions of the pipeline system. Also included are the replacements of sections of the pipeline that are damaged or suffer from corrosion. It is appropriate to consider these expenditures as capital. If portions of the TPIP costs were treated as operating and maintenance expenses then the revenue requirements of the Company in the 2003 to 2007 period would increase and the rate increase sought for 2003 would be greater.

b. Interior Capacity Expansion And Reinforcement Projects

In the last 10 years BC Gas met the load growth on its transmission system through the addition of the Surrey/Langley pipeline, the Interior Pipeline Reinforcement project which included the SONG pipeline and the Kitchener and Midway compressor stations, the Southern Crossing Pipeline and the Langley Compressor Station. However, the pipeline system is forecast to require additional firm capacity in certain areas in the future.

Major capital projects of a CPCN nature in 2002 and during the period 2003-2007 include three capacity upgrades. Customer growth in the Okanagan has slowed down recently, and BC Gas has found ways to reduce load and increase capacity from existing facilities. The Company forecasts that capacity expansion will be required before the winter of 2006/07.

c. Armstrong Compressor Station Project (Order C-6-02)

Growth on the Salmon Arm lateral and Interior Transmission System is the driver for the Armstrong Compressor Station Project.

Approval of expansion of this part of the Interior Transmission System was originally applied for in 1998 and since that time it has been the subject of a number of studies. As a result, and to defer the project BC Gas undertook the Heatsaver targeted DSM program, as well as modifications to design parameters of the existing system. A small compressor is now required.

An 800 HP reciprocating compressor unit in the Armstrong area is required for winter 2002/03 and costs of $4.2 million (before AFUDC) have been allowed under a recently issued CPCN. BC Gas is in the process of constructing the compression facilities that will be capable of local, manual operation when required during the winter of 2002/3. The balance of construction, allowing automated remote operation, will be completed in the spring of 2003.

d. Okanagan Reinforcement (Naramata Loop And Kitchener Compressor Station Projects)

Growth within the Thompson-Okanagan area will necessitate reinforcement of the transmission facilities serving the region. Examination of the requirements and alternatives for reinforcement of the Interior Transmission System formed part of both the 1998 and 1999 SCP hearings.

BC Gas has undertaken a resource review and concludes that the best resource addition is a program of phased looping of the pipeline between Penticton and Kelowna. Since the SCP hearings the need for reinforcement has been delayed due to lower than expected customer load growth and the optimization of existing facilities in combination with the SCP. The current forecast indicates that the reinforcement will be required prior to winter 2006/07.

The first phase of this program consists of a 24 km, 20 inch, 1035 psig loop from the north end of the SONG pipeline at Ellis Creek Station to north of Naramata. The loop is projected to be built and placed in service in 2006, at a cost of $33 million. This project will be the subject of a CPCN application.

In addition to the loop, increased compression power will also be required at the Kitchener B compressor station. This will be accomplished through the addition of a third compressor unit at this station at a cost of $19.9 million, also planned for 2006. It is expected to be the subject of a CPCN application and has not been included in the Company's forecast of Category B capital expenditures.

e. Southern Crossing Pipeline Project (Order C-11-99)

The Southern Crossing Pipeline ("SCP") project is 24 inch high pressure transmission pipeline and associated facilities looping the existing BC Gas transmission pipelines from the TransCanada (B.C.) system near Yahk to a point on the BC Gas transmission system near Oliver. The project also includes compression facilities at the existing Kitchener Compressor Station near Yahk and a new compressor station near Hedley. The SCP went into service in November 2000 and restoration and right of way rehabilitation expenditures continued in 2001 and 2002. The addition to 2001 rate base related to SCP was $356.6 million, including AFUDC, and the addition to rate base associated with SCP for 2002 is $31.4 million, including AFUDC. An additional $8.1 million is forecast to be spent in 2002, which will be included in 2003 rate base, representing a saving of $12.9 million from the approved project spending cap of $409 million.

f. Fraser Valley Compressor Station Project (Order C-14-99)

This Langley facility consists of two 7,000 horsepower compressors to meet the peak day requirements of customers in the Lower Mainland including the B.C. Hydro operations at the Burrard Thermal plant. This project was budgeted at $31.7 million. The 2001 addition to rate base was $22.8 million, including AFUDC. The addition to rate base for 2002 is forecast to be $1.9 million and further expenditures of $4.0 million are expected in 2002 that will impact 2003 rate base; in aggregate these expenditures represent a positive variance of $3.0 million from budget.

g. Work Management Systems/Preventive Maintenance (Order C-6-00)

WMS/PM is a system that manages maintenance and installation work. The Preventive Maintenance (PM) component of the system reduces ongoing maintenance costs, enables a risk-based approach to preventative maintenance, and provides a standardized system to collect historical maintenance data for gas plant. The Work Management System (WMS) component of this project is a replacement of the current technically obsolete system used by installation groups in completing construction work. This project had expenditures from 1999 to 2001, and continuing in 2002. Its total cost, including AFUDC, is forecast to be $11.7 million, with $5.0 million added to rate base in 2002 and the balance in 2003. Benefits arising from this project are reflected in Distribution costs for 2003 and beyond.

h. Integrated Resource Management (“IRM”) (Order C-15-99)

IRM is a work assignment, dispatch and field monitoring system that was implemented in 2001. It provides automated scheduling and dispatch capability for the management of resources (people, equipment and materials). The preparation and dispatch of all routine customer service fieldwork requests have been centralized at the Surrey Operations Centre. Work is transmitted to the field using mobile data dispatch technology and in-truck terminals. This project was completed in 2001 at a cost of $5.7 million, including AFUDC, with that amount being in rate base as of 2002. The benefits from this project are taken into account in the costs contained in this Application.

i. Automated Mapping/Facilities Maintenance (“AM/FM”) (Order C-7-97)

AM/FM is a geographic information system and database that Distribution has adopted to automate the manual and paper-based methods used for mapping and facility record keeping of gas distribution system information. This system replaces critical gas distribution graphical records that were kept in paper form. Many of the paper records were old, fragile and in danger of being lost. This IT project was funded through Category C capital over the past five years as directed by BCUC Order No. C-7-97. The project was implemented in phases from 2000 to 2002 at a total cost of $14.4 million. AM/FM provides value by improving record keeping, accessibility to gas system data, emergency handling and customer response. The project proceeded on the basis that future operating and capital benefits would be realized. These benefits are being realized and have reduced the overall Distribution costs.

The AM/FM system is a key online information source for BC Gas to respond to the BC OneCall system, of which BC Gas is a member. OneCall services such as the one in British Columbia are a critical tool in reducing third party damage to pipeline systems, as well as to other utility infrastructure. The AM/FM project will also enable the exchange of data in digital form so that BC Gas can participate in data sharing with other utilities, municipalities and government agencies.

j. Systems For Transmission Records

It is necessary for BC Gas to manage and maintain complete and accurate records of its transmission plant in order to comply with operating codes.

BC Gas presently stores and accesses its transmission system facility records through a number of different processes, in a mixture of hard-copy and electronic formats, and in several locations. Examination of these processes during the Transmission Operations System Review (“TOSR”) resulted in the identification of a number of deficiencies that require timely correction to meet the CSA Z662 operating code on an ongoing, consistent and cost-effective basis. Several options are being considered, one option being an electronic system that involves digitizing all transmission-related documents and implementing a search/retrieval system. This project is the solution that has been tentatively selected, and is planned for 2003 and 2004 at an estimated cost of $2.5 million. Its costs have been included in the Category C capital forecast discussed below.

The AM/FM GIS system for transmission records project involves placing all transmission-related facility information into the AM/FM system, software licenses and training employees on system use. BC Gas is presently using the AM/FM system for its distribution and intermediate pressure pipeline systems with success and this project will extend benefits to the higher-pressure pipelines.

The BC Gas Transmission system was not included in the scope of the original AM/FM project, which commenced in 1997. The processes and technology in place at the time were viewed as sufficient given the relatively small linear size of the transmission system and small number of customers directly attached to it. With BC Gas joining the BC OneCall system for utility locate information, improvements in the functionality of AM/FM systems, and the Company acquiring experience in utilizing and maintaining the AM/FM system, the migration to AM/FM for transmission-related facilities makes business sense.

There are a number of manual processes and growing number of manual work-arounds necessary to provide outside agencies or persons with transmission system information through the BC OneCall network. Additionally, BC Gas is finding that a growing number of outside agencies and municipalities require electronic exchange of landbase and transmission piping location information. Including the transmission system in the AM/FM system will streamline the back office processes that allow the public to obtain information on all BC Gas facilities from a single source, minimize the chance for miscommunications or mistakes, and improve the effectiveness of damage prevention programs.

The AM/FM GIS system for transmission records project is planned for 2005 and is estimated to cost $2 million. Its costs have been included in the Category C capital forecast discussed below.

k. Program Mercury (Order C-7-99)

Program Mercury was commenced as a BC Gas project to provide a new customer information solution, which consists of new systems (specifically a new Customer Information System and advanced call handling technologies), repatriation of BC Gas' customers from B.C. Hydro, and significant business process restructuring.

In December 2001, BC Gas applied for Commission approval of the disposition of the Program Mercury assets and approval of customer care arrangements between BC Gas and CustomerWorks LP. By Order G-29-02 the Commission approved the disposition and the arrangements with CustomerWorks. The assets associated with Program Mercury have been sold by BC Gas and have been removed from the rate base of the Company.

Part of Program Mercury is the movement of customers in the Lower Mainland from the billing systems of B.C. Hydro and the introduction of monthly billing of the BC Gas customers in the Lower Mainland. The monthly billing of those customers will reduce the working capital requirements of the Company, and rate base is reduced accordingly. In this Application the rate base for 2003 has been reduced to reflect the monthly billing of customers in the Lower Mainland.

I. Other Transmission Related Expansion Projects

Nichol/Coquitlam loop - The decision by B.C. Hydro to increase its contract demand under the Burrard Bypass Agreement drives the need to accelerate the timing of looping between Nichol and Coquitlam Stations in the Lower Mainland. This circumstance was contemplated in the discussions regarding the Bypass Agreement and Langley Compressor Station approvals. Increased capacity requirements of Burrard Thermal and of Centra Gas BC will require pipeline expansion, but the long-term implications surrounding the Georgia Strait Crossing project create uncertainty regarding the actual amount of capacity required. Further complicating the picture is the uncertain prospect for independent power generation at greenhouse operations in Delta and general growth in the greenhouse industry. While immediate implications of greenhouse growth only affect the distribution system in the Ladner area, long-term implications may influence the need and timing of the Nichol-Coquitlam loop. This project is currently forecast to be built during 2005 and 2006 at a cost of $23.9 million (including AFUDC). It is expected to be the subject of a CPCN application and has not been included in the Company’s forecast of Category B capital expenditures.

Tilbury LNG Tank Upgrade Project - Compliance with applicable codes relating to the consequence of a seismic event is the major driver of the Tilbury LNG Tank Upgrade project. Long-standing issues with regard to the inner tank hold down system also need to be addressed. BC Gas has chosen a course of action it believes will have the least impact on tank availability and cost, but which addresses the critical needs. The overall project is estimated at a total cost of $6.6 million and the work is being undertaken in two phases. This course of action has been adopted to minimize the risk of unforeseen technical challenges delaying completion of work and placement of the storage tank back into service in time to allow filling with LNG for winter 2002/03.

Phase I, currently underway, involves emptying and warming the tank; inspecting the overall condition of the inner tank, inner tank hold down strap sites and the liquid withdrawal line; installing an internal shutoff valve; installing a liquid density gauge and, if necessary, repairing identified defects. This work should be complete by mid-July to allow the tank to be refilled for the upcoming heating season. In progress and continuing past July is the formulation of a plan for Phase II based on analysis of the inspection results.

Phase II will involve further work at inner tank hold down strap sites and full leak repair based on Phase I findings. Phase II is presently planned for 2004. The timing will depend on the availability of future alternative gas peaking supply alternatives in the form of transportation infrastructure capacity. This precaution will be taken to mitigate the risk of unforeseen project schedule delays once Phase II work commences.

Phases I & II have been budgeted under the Company's Category B capital expenditures discussed below. The estimated cost for Phase I is $3 million. Phase II has been budgeted at $3.6 million.

2. REGULAR CAPITAL ADDITIONS

The rate base for BC Gas for 2003, and rates paid by customers, will also be affected by the regular capital additions during 2002 and 2003. Regular capital expenditures involve small and large projects of many types, and include the maintenance and expansion of pipe in the ground, together with the other facilities and systems required to provide service to the large and diverse number of BC Gas customers. Ongoing capital expenditures are required to maintain the integrity of the distribution and transmission facilities of the Company in the face of increasing regulatory and public expectations. They are necessary to provide safe and reliable service, to enable the Company to provide service to new customers, to replace the piping and other infrastructure as required, to respond to the information needs and inquiries of customers, and to provide the information and support systems necessary for the many aspects of BC Gas' business.

As part of the 1998 – 2001 Performance Based Rate Plan the regular capital expenditures of BC Gas were divided into three categories: Category A - Mains, Services and Meters; Category B - Transmission and Distribution System Integrity and Reliability; and Category C - All Other Plant. Projects approved by Certificates of Public Convenience and Necessity were Category D. The annual capital expenditures in Categories A, B and C were determined by a series of formulas that included base costs, cost drivers, inflation escalators and productivity offsets. The expenditures in Category A were unit cost based while the expenditures in Categories B and C were more aggregate in nature. Capital expenditures for 2002 do not come within the Performance Based Rate Plan but, as noted previously, financial discipline remains in place since 2002 rates were not increased to reflect additional capital expenditures.

The regular capital additions for 2003 are discussed below in terms of Categories A, B and C since persons participating in BC Gas revenue requirement proceedings are familiar with the terms, but it should be noted that the regular capital expenditure forecasts have not been developed using the formulas applicable to the 1998 - 2001 PBR Plan.

a. Category A - Mains, Services And Meters

The capital expenditures that were contained within Category A are those associated with the installation of new mains, services and meters. These expenditures are necessary to attach new customers to the gas distribution system. A portion of the Category A expenditures are to purchase or remanufacture gas meters utilized for meter exchange activities, as required to maintain accurate gas measurement for the existing customer base.

The number of new services is the primary driver for the Category A type of expenditures. New services, in turn, are driven by customer additions, new housing activity and household formation. A secondary driver for Category A expenditures is the number of meter exchanges scheduled each year. These are driven by the total number of customers connected to the gas distribution system and the Measurement Canada Standards.

Current new customer activity levels are relatively low. A slowdown in the provincial economy, relatively low housing starts, and commodity price increases of the recent past, have all contributed to this decline in customer additions. For 2002 and 2003 the customer additions are expected to recover somewhat from the low levels experienced over the last few years, to be approximately 7,500 and 9,300 respectively.

Challenges faced by BC Gas in containing the costs of Category A type of capital include the declining level of capital work and unavoidable losses in economies of scale, increasing customer and general public expectations for enhanced levels of service and safety, and inflationary increases in wages and materials. Further, reductions in the BC Gas workforce have made it challenging for BC Gas to continue to meet emergency response targets and the level of service and safety the public has come to know.

Since 1997, new services unit costs increased 28% or approximately 5% per year. The number of new services is the primary driver of Category A service expenditures and new service activity is at historically low levels. From 1997 to 2001, the number of new services declined from 15,141 to 7,210, which represents a decrease of 52%. Net customer additions fell from 16,468 to 4,874, a decrease of 70% over the same period. This in turn drove losses in economies of scale for field personnel and resulted in less efficient customer attachment processes and higher unit costs.

For example, an install crew headquartered in Vernon previously drove to Lumby once a month and was able to install three services if uninterrupted by an emergency. Today, the crew drives to Lumby once a month with only one service to install and because of the lower number of crews, may be responsible for responding to an emergency elsewhere in the service territory. Travel time and fuel costs are allocated against only one service, versus the three services that would have received a portion of the costs in high activity years. If interrupted by an emergency, set up, take down and travel time will require duplication, which results in a further upward pressure on unit costs.

New mains unit costs have also increased. This is, in part, also the result of significantly reduced activity levels due to lower new services and customer additions. Activity levels for mains declined 64% from 1997 to 2001, which resulted in economy of scale losses. For example, in 1997 BC Gas regularly used contract installers for new mains work in the Interior. The contractors were not interrupted by emergency response activities and their work focussed mostly on lengthy sections of new main. Today, BC Gas crews complete the majority of this work and the sections of new main are shorter. BC Gas install crews are also emergency response crews. They may be interrupted in installation work by having to respond to an emergency elsewhere. Not until the emergency is resolved are they able to travel back to and continue with the installation of the new main. The additional travel, take down, and set-up time results in higher unit installation costs.

There are other factors that have caused BC Gas' crews to be less cost efficient in the installation of mains and services. The gas main installation jobs that BC Gas has undertaken have changed as well. In the early to mid-1990s there were a number of gas extension projects to service rural areas. These jobs tended to have high production rates and low unit costs. This tended to reduce the average unit cost for mains installation. These jobs are no longer occurring, resulting in larger numbers of smaller and shorter duration jobs, again resulting in lower production rates, higher travel costs and higher overall unit costs. Costs have also increased in terms of labour rates, services, materials and fuel due to inflation.

Some of the existing external challenges will continue to place pressure on BC Gas. Increases in natural gas commodity prices and commodity cost uncertainty in the long term have become factors in terms of new customer capture rates and new customer additions. Electric and gas space heating costs converged to a significant extent over the past two years. Developers and homebuilders may choose other energy sources for new construction. As this happens, it reduces capital activity, which will continue to adversely impact unit costs.

BC Gas has taken a number of steps to reduce the impact of productivity losses and economy of scale losses attributable to declining capital activity levels. First, as activity levels declined, contract installers were removed. Second, BC Gas install and emergency response crews were reduced through attrition, re-assignment and layoff.

Indirect costs, such as salaries, benefits and vehicles for drafters, planners, managers and engineers were reduced. For example, indirect costs in 1997 totalled $5.5 million and represented 26% of the new services and new mains expenditures. The remaining costs were largely variable crew, equipment, material and services costs. In 2001, comparative costs totalled $2.8 million, which represents a reduction of 49% over five years. The current level of indirect expenditure represents 21% of the new services and new mains expenditures. Variable costs tied to activity are now a larger percentage of the total cost. The majority of these overhead reductions were made in conjunction with Interior office closures, process standardization, facilities centralization, and information technology implementations, particularly AM/FM. Direct costs were somewhat more difficult to reduce than routine variable crew costs and generally came as step decreases as opposed to gradual reductions. Employee knowledge and experience is difficult to replace and BC Gas has had to be certain that the activity level cycles can be accommodated with the remaining workforce. BC Gas continues to look at ways to further variabilize these costs with activity levels and seeks a multi-year comprehensive PBR arrangement in order to cultivate efficiencies through short and long-term economic cycles.

BC Gas also decreased the size and cost of its vehicle fleet to reduce the impact of a lower amount of capital work. Under-utilized backhoes, haul trucks and crew trucks were removed from the fleet. The vehicle fleet is currently at a level that allows BC Gas to respond to emergencies and complete current levels of capital work within a reasonable timeframe. Interior vehicles were sold to B.C. Hydro and leased back at prevailing rates. The change in the fleet ownership made adjustments to fleet size easier and helped BC Gas to further variabilize vehicle costs.

BC Gas has also introduced smaller, alternate crew compositions who utilize mini-excavators and other types of excavating equipment to achieve a better match between job requirements and resources assigned which in turn reduces installation field costs.

Crew compositions have also been changed. Historically, a standard crew size dispatched to an installation job site was three individuals; crew leader (welder), distribution mechanic (labourer) and equipment operator plus crew truck, trailer and backhoe. BC Gas initiated discussions with the IBEW in 1999, resulting in new collective agreement language that allows crew size to vary based on job requirements while maintaining employee and public safety. BC Gas now dispatches crews of two individuals where appropriate to job sites; one operates the excavating equipment and performs the distribution mechanic work (manual ditch work) when not operating the excavating equipment. BC Gas trained a significant number of its field personnel to operate mini-excavators, and reduced the requirement for higher cost dependent backhoes and operators in the Lower Mainland.

BC Gas also adjusted the size of its workforce to keep capital unit costs as low as possible in this lower activity level environment. Seasonal layoff notices were issued in 2001 to field workers in both the Interior and Lower Mainland. These staffing adjustments match the numbers of qualified personnel to levels of available work while maintaining adequate emergency response capabilities. Many of these layoffs are now permanent.

In late 2001 BC Gas negotiated a five-year labour contract with the IBEW, its field workforce. The long-term contract provides BC Gas with certainty on field rates as well as flexibility in hours and skillset utilization. Also in late 2001, BC Gas further reduced its field workforce with an early retirement incentive package. Vehicles were further reduced concurrent with these workforce reductions.

Looking into the future, the age of the distribution system will be an increasing challenge. For example, meters installed during high activity periods of the early 1990s will begin to be due for recall within the 2003 - 2007 period. Meter recalls average approximately 47,000 per year from 2002 - 2007 compared to 42,000 per year from 1995 - 2001, a reflection of the growing base and the business cycle 14 years ago.

Another future business challenge that BC Gas faces is the tension between the need for workforce flexibility and employee requirements. BC Gas' need for further workforce flexibility and generic multi-skilled workers, coupled with the need to contain cost increases are at odds with union demands for job security and wage and benefit enhancements.

Five-year labour agreements between BC Gas and its two labour unions, the IBEW and the OPEIU, were recently ratified by union members. The five-year agreements provide some stability in which union and management can work to resolve work assignments and employee roles as new technologies and redesigned business processes continue to evolve. The agreements create a reasonable balance between the need to change the number of employees and their roles to achieve efficiencies and the need to keep employees motivated to provide safe reliable service for customers. In exchange for workforce flexibility, labour rates were negotiated that will provide for real wage increases to employees over the life of the agreements. It should be noted that a large percentage of operations employees will be reaching retirement age within five to eight years.

BC Gas is responding to the challenge by working toward a model of a more generic, multi-skilled worker, with specialists only where job requirements dictate. Flexibility and interchange ability through cross-training are two attributes that the Company will continue to enhance in the field and support workforces. This gives BC Gas a greater range of choices in responding to emergencies and other work, reducing travel time and visits to the same site by multiple BC Gas employees. These evolving measures are reflected in historical and forecast costs in both operating and maintenance expenses and capital.

Processes and procedures are being built that will make it possible to more effectively vary our staffing levels according to activity levels. The goal is to keep unit costs as low as possible, irrespective of housing starts and commodity prices, factors both beyond the control of the Company. As workload increases, contractors will be used in new ways for workload peaking purposes, while continuing to maintain a robust core of utility emergency and operate/maintain field personnel. The Company's goal is to offset cost pressures due to real wage increases with the measures discussed above and to maintain unit costs in real terms as has been reflected in the forecasts in the Application.

These kinds of changes take time. The culture and behaviour of the workforce must be moulded to new business realities, which requires a tremendous amount of management and employee effort to achieve. It is not uncommon for new initiatives to face stiff opposition, particularly if job loss or significant change is required. Companies that undergo these types of changes require many years for the improvements to be fully realized and sustained. BC Gas can best respond to these challenges in an environment of a long-term PBR that will provide sufficient time for the Company to obtain an economic payback on efforts taken to achieve these difficult changes.

The forecast of new Category A activity levels starts with the forecast of customer additions.

The customer additions forecast is converted into a forecast of new service activity levels based on an historical relationship. From 1991 to 1997 the ratio of new services for each customer addition was approximately 0.95:1, although more recently this ratio increased. Using ten-year historical ratios and removing the high and low anomalies, the remaining eight years arithmetic average is 0.98:1. Based on the most recent five-year historical ratios, and without adjusting for anomalies, the ratio is 1.08 new services for each net new customer (the ratio being above one reflects the loss of customers due to conversion to other fuels or the demolition of existing premises). BC Gas has selected 1.0 as the ratio used in the forward projection for 2003 and also for the period going out to 2007.

New mains installation activity levels have a historical relationship with new service activity levels that are also driven by new customer additions. Based on ten-year historical ratios and removing the high and low anomalies, the remaining eight-year arithmetic average is 18 metres of new main per new service. Using the most recent three-year historical ratio, and without adjusting for anomalies, the ratio is 14 metres per service. In 2001, the ratio decreased to 12 metres primarily because of lower housing activity; both the addition of infill customers and a higher capture rate on multi-family residential customers (as opposed to single family sub-divisions) contributed to the decline in the ratio. The new mains forecast for 2003 and beyond has used the 1999 – 2001 three year historical average of 14 metres per service as it is the most representative of the current environment.

The number of gas meters to be purchased or remanufactured is the forecast number of customer additions plus the number of meter exchanges (recalls) scheduled to be performed in a given year plus an allowance for scrapped meters.

Meter exchange is the activity of removing in-service gas meters and replacing them with new or remanufactured meters to maintain accurate measurement, as required by the *Electricity and Gas Inspection Act.* The purchase of new or remanufactured meters is a capital expenditure while the exchange of the gas meters is an Operating & Maintenance expense. Residential and some small commercial meter exchanges require a brief interruption of gas service to a customer's premise, and the relighting of gas appliances by a BC Gas service technician or qualified contractor once the meter exchange has been completed.

Residential gas meters are expected to maintain their accuracy for about 14 years before replacement. BC Gas exchanges or renews approximately 1/14th of its residential meter population annually. In addition, approximately 3,000 commercial and industrial meters are also recalled each year as well as 6,000 residential sample meters which serve as a representative sample of the entire in-service fleet.

A summary of projected and forecast Category A activity levels and expenditure is outlined in the following tables.

FORECAST Capital - Category A: Mains, Services, Meters

Activity levels

	2002 Projected	**2003** Forecast	**2004** Forecast	**2005** Forecast	**2006** Forecast	**2007** Forecast
Customer additions	7,476	9,265	8,464	8,521	8,793	8,864
New Services	7,476	9,265	8,464	8,521	8,793	8,864
New Mains (Metres)	92,431	129,724	118,496	120,918	121,478	124,096
Meters - New	7,476	9,265	8,464	8,521	8,793	8,864
Meters - Exchanges	46,716	46,304	46,823	47,373	47,971	48,500
Meters - Total	54,192	55,569	55,287	55,894	56,764	57,364

FORECAST Capital - Category A: Mains, Services, Meters

Annual Capital Expenditures ($ millions)

	2002 Projected	2003 Forecast	2004 Forecast	2005 Forecast	2006 Forecast	2007 Forecast
New Services	8.4	10.6	9.9	10.4	10.7	11.1
New Mains	4.7	6.0	5.8	5.9	6.1	6.4
Meters	14.2	16.9	17.1	17.5	18.0	18.4
Total Nominal	**27.3**	**33.5**	**32.8**	**33.8**	**34.8**	**35.9**
Total Real	**27.3**	**32.9**	**31.7**	**32.0**	**32.3**	**32.6**

Note: Real totals in 2002 values.

The primary reasons for the $6.2 million increase in total Category A expenditures from 2002 to 2003 are increased activities and higher unit costs for meters. The forecast for activities is summarized in the preceding table and the development of the meter unit cost is discussed below.

The history of Category A activities and expenditures is outlined in the following tables:

HISTORICAL Capital - Category A: Mains, Services, Meters

Activity levels

	1997 Actuals	1998 Actuals	1999 Actuals	2000 Actuals	2001 Actuals	2002 Projected
Customer additions	16,468	10,447	11,293	7,262	4,874	7,476
New Services	15,141	10,857	9,590	8,305	7,210	7,476
New Mains (Metres)	238,794	185,592	155,003	118,689	79,207	92,431
Meters - New	16,468	10,447	11,293	7,262	4,874	7,476
Meters - Exchanges	42,046	41,872	42,446	39,043	46,550	46,716
Meters - Total	58,514	52,319	53,739	46,305	51,424	54,192

HISTORICAL Capital - Category A: Mains, Services, Meters

Annual Capital Expenditures ($ millions)

	1997 Actuals	1998 Actuals	1999 Actuals	2000 Actuals	2001 Actuals	2002 Projected
New Services	13.9	11.2	10.4	9.3	8.4	8.4
New Mains	7.4	5.7	5.7	5.9	4.6	4.7
Meters	16.2	13.7	15.5	14.7	13.7	14.2
Total Nominal	**37.5**	**30.6**	**31.6**	**29.9**	**26.7**	**27.3**
Total Real	**39.9**	**32.6**	**33.3**	**30.8**	**27.1**	**27.3**

Note: Real totals in 2002 values.

A summary of the projected and forecast unit costs for Category A expenditures is in the table below.

FORECAST Capital - Category A: Mains, Services, Meters

Unit Costs

calculated in nominal $'s	2002 Projected	2003 Forecast	2004 Forecast	2005 Forecast	2006 Forecast	2007 Forecast
New Services (per Service)	$ 1,130	$ 1,142	$ 1,174	$ 1,215	$ 1,213	$ 1,252
New Mains (per Metre)	$ 51	$ 46	$ 49	$ 49	$ 51	$ 51
Meters - New/Exchanges	$ 261	$ 304	$ 309	$ 314	$ 317	$ 322

Forecast unit costs for mains and services were established using three-year historical averages from 1999 to 2001. A fixed or base budget was established for both mains and services and a variable component driven by activity was also estimated. The variable component was forecast using three-year historical variable costs. The fixed component was also forecast using three-year historical fixed costs. The amounts shown in both the historical and forecast unit cost are a blend of fixed and variable costs.

The table below summarizes historical unit costs for services and mains.

HISTORICAL Capital - Category A: Mains, Services, Meters

Unit Costs

calculated in nominal $'s	1997 Actuals	1998 Actuals	1999 Actuals	2000 Actuals	2001 Actuals	2002 Projected
New Services (per Service)	$ 921	$ 1,035	$ 1,089	$ 1,123	$ 1,169	$ 1,130
New Mains (per Metre)	$ 31	$ 31	$ 37	$ 50	$ 58	$ 51
Meters - New/Exchanges	$ 276	$ 262	$ 288	$ 316	$ 266	$ 261

Unit costs for meters were also developed from the three year 1999 -2001 historical average. A blended unit cost of all customer types was used for meter exchanges and installs. Meter costs include the purchase or remanufacture of residential, commercial and industrial meters and regulators; the testing and handling of new and remanufactured meters and regulators; prefabrication of meter set assemblies; installation of new meter sets and regulators; meter set renewals and upgrades and the purchase of demand metering devices; and electronic volume correction equipment.

Average meter unit costs have increased from 1997 to 2001 due, in part, to inflationary cost increases in fabrication and materials. Meter unit costs also fluctuate due to variations in the mix of meter set types – some of the larger, more complex commercial and industrial sets are significantly more costly due to higher material and manufacturing costs. Additionally, the number and mixture of commercial and industrial meters are by their nature difficult to forecast accurately. Unit costs also faced upward pressure because of unexpected code changes.

A replacement program for gas regulators also impacts the forecast of unit costs for meters. An amount of $700,000 per year has been added over and above forecasts based on historical costs to provide for a replacement program for gas regulators. This is a new program initiated in 2002 to renew gas regulators on a nominal 30-year cycle. Regulators have a finite life expectancy but no formal program has previously existed for residential and small commercial class pressure regulators. Under the BC Gas program regulator exchange will occur on every second meter change at a premise. The replacement program costs have been factored into the meters capital funding in 2003 by an increase over the three-year average historical unit cost of $12 per unit.

A portion of the costs of Category A activities is paid directly by new customers. Contributions in Aid of Construction (“CIAC”) are funds received from customers and developers to offset Category A expenditures when the main extension fails BC Gas’ economic test or when the estimated service line installation cost is greater than the Service Line Cost Allowance. Also, a service line installation fee of $215 is charged to all customers for new service lines. This fee is treated as a CIAC. Contributions in Aid of Construction are not included in the Category A, B and C capital forecasts but are accounted for separately as CIAC’s. Net CIAC additions for 2003 is forecast at $10.9 million. The detailed forecast CIAC for 2003 –2007 can be found in Section H, Tab 3, Pages 4.1/4.2.

The Category A capital costs forecast for 2003 and forward to 2007 represent the level of this type of capital required to provide safe, reliable and efficient service to the existing customers of BC Gas and to new customers to be added to the BC Gas system.

b. Category B - Transmission And Distribution Systems Integrity and Reliability

The capital expenditures within Category B include gas system improvements to add capacity to meet customer growth and expenditures related to safety and reliability of the approximately 20,000-km distribution and transmission system. Projects of a special nature, generally those with project budgets greater than $5 million, have typically been reviewed by the Commission through a separate CPCN process.

The key drivers for Category B expenditures are safety, reliability and growth. Capital additions to the transmission and distribution plant are required to maintain a high degree of system availability while protecting the public, landowners, customers and employees through assurance of pipeline and facility integrity. Those additions have to be completed in a cost-effective manner while recognizing the pressures associated with ageing of the transmission and distribution infrastructure, increasing urbanization around rights-of-way and facilities, and increasing expectations by the public and government with regard to public safety, particularly after several publicized pipeline failures. The other key driver is customer additions that will inevitably require system expansion and reinforcement to meet peak day demands.

Part of the Category B expenditures are facilities required to meet customer growth and maintain reliability of the system. The key tool used to determine the capital requirements necessary for these facilities is the Company’s five-year infrastructure plan. This plan is developed using a detailed network analysis process that incorporated the needs of each community with different weather patterns, growth rates, geographic location, and specific customer attributes. The planning cycle starts with the gathering pressure information from hundreds of points throughout the system, which is adjusted for weather differences. Computer programs are used to analyze the flows on gas distribution grids and the transmission system to model growth and to develop a plan that minimizes the long-term costs of meeting customer needs while meeting appropriate codes and standards. After flow requirements are understood, the other components of the system (such as gate stations, odourant facilities, metering, etc.) are analyzed to ensure everything meets the design conditions. Once the network analysis of the transmission and distribution systems is complete, specific projects to meet the load growth are determined, evaluated and prioritized. The evaluation is centred on ensuring that undue risk is not taken with regard to meeting peak day obligations or compromising system integrity. Where possible, alternate procedures such as manual control are examined to assist in project deferral. The final output of the review is the five-year integrity infrastructure plan which is then used to create the five-year budget for Category B expenditures.

Other Category B capital investments are related to the safety and integrity of the system and the increasing attention of regulators and the public related to safety concerns. As urban development increases, encroachments over transmission system rights of way occur. As the population density around segments of the distribution and transmission systems increases, changes in location classifications are required which drives upgrade expenditures; thicker wall pipe or looping may be required when greater population density in the vicinity of a line requires pressure in the line to be decreased. Inspection and upgrades, and relocations of pipelines in roadbeds result from changes to the road systems. Environmental protection of watercourses and other areas, upgrading to meet seismic standards and replacement of obsolete components also drive the need for specific projects.

BC Gas, like other businesses, faces environmental requirements that are becoming more stringent. In many cases the environmental requirements result in additional expenditures to attain compliance. The activities relating to maintenance and management of rights of way have been particularly impacted. Any work around bodies of water now requires an environmental work plan with mandatory follow-up reports. While BC Gas agrees that protection of the environment is important, the costs of the Company are impacted.

Under the 1998 - 2001 Performance Based Rate Plan the annual target for Category B capital expenditures was based on an initial amount of spending on system integrity and reliability, adjusted for system throughput and number of new customers. The actual level of capital spending in Category B has exceeded the target amounts in the last two years. Factors requiring a number of major public safety projects arose during the 1998 - 2001 Performance Based Rate Plan and were incremental to the levels of spending within the Category B targets set at the beginning of the PBR Plan.

Examples of such incremental requirements are the replacement of distribution piping in Quesnel, rehabilitation of pipelines in Burns Bog stemming from landfill activities, addition of secondary containment around odourant vessels and line heaters and installation of safety snowsheds to protect meters prone to snow damage.

Looking forward, the forecast Category B capital expenditures are

FORECAST Capital - Category B: System Integrity and Reliability

Annual Capital Expenditures ($ millions)

	2002 Projected	**2003** Forecast	**2004** Forecast	**2005** Forecast	**2006** Forecast	**2007** Forecast
Transmission Plant	11.4	8.2	11.6	5.8	4.9	5.8
Distribution Plant	9.0	17.2	13.4	11.5	17.0	9.2
Total Nominal	**20.4**	**25.4**	**25.0**	**17.3**	**21.9**	**15.0**
Total Real	**20.4**	**25.0**	**24.1**	**16.4**	**20.3**	**13.7**

Note: Real totals in 2002 values.

The Category B capital expenditures since 1997, and projected for 2002, are set out in the following table.

HISTORICAL Capital - Category B: System Integrity and Reliability

Annual Capital Expenditures ($ millions)

	1997 Actuals	**1998** Actuals	**1999** Actuals	**2000** Actuals	**2001** Actuals	**2002** Projected
Transmission Plant	11.2	8.4	10.6	9.2	8.6	11.4
Distribution Plant	6.1	3.3	12.8	19.0	8.9	9.0
Total Nominal	**17.3**	**11.7**	**23.4**	**28.2**	**17.5**	**20.4**
Total Real	**18.4**	**12.4**	**24.6**	**29.1**	**17.7**	**20.4**

Note: Real totals in 2002 values.

For 2003, and into the near future, Category B capital expenditure requirements relate to the replacement of ageing infrastructure, updating facilities to meet changes to applicable codes and lesser amounts associated with capacity additions to meet customer growth. The transfer of transmission integrity expenditures (discussed above in the Major Projects section) to a separate CPCN application process reduces the future transmission related expenditures that would have been within the Category B type of capital expenditures. The average total Category B expenditure for the past three years is approximately $23 million; the total average amount forecast from 2003 to 2007 is $20 million in real 2002 dollars. The forecast expenditures are discussed below as Distribution and Transmission expenditures.

The proposed level of Category B expenditures is prudent and reasonable, particularly when considered in terms of the nature of the BC Gas system and its age. BC Gas services a large and diverse customer base with approximately 20,000-km of distribution and transmission pipeline system, hundreds of gate stations, eight compressor stations and a LNG facility. Much of the infrastructure is over 40 years old and requires a significantly higher level of expenditures when compared to new facilities to ensure that the Company meets its commitment to public safety, and its obligation to provide reliable service.

i) Distribution Category B Capital Expenditures

Investments in Category B Capital are required for the distribution system to maintain a high degree of system availability while protecting the public, customers and employees. Category B type of expenditures mitigate the risk of loss from system outages and business interruptions. Safety, reliability and growth expenditures are becoming increasingly important as insurance deductibles have escalated substantially for system outages and business interruption.

Distribution Category B capital expenditures for risk mitigation include upgrades to the gas distribution system to meet seismic standards, enhancements to the system in land slippage areas, and expenditures to ensure environmental protection of water courses.

The table below summarizes the forecast of Distribution Category B from 2002 through 2007.

FORECAST Capital - Category B: Distribution Plant details

Annual Capital Expenditures ($ millions)

	2002 Projected	2003 Forecast	2004 Forecast	2005 Forecast	2006 Forecast	2007 Forecast
Distribution Plant System Improvements	8.5	12.9	10.0	8.4	14.0	6.0
Distribution Risk Mitigation - Secondary Containment	0.5	2.6	2.2	1.8	1.7	1.8
Distribution Risk Mitigation - Seismic		1.4	1.0	1.1	1.1	1.1
Distribution Risk Mitigation - Land Slippage		0.3	0.3	0.3	0.3	0.3
Distribution Risk Mitigation - Meter Protection						
Total Nominal	**9.0**	**17.2**	**13.5**	**11.6**	**17.1**	**9.2**
Total Real	**9.0**	**16.9**	**13.0**	**11.0**	**15.9**	**8.4**

Note: Real totals in 2002 values.

The table below summarizes the history of Distribution Category B from 1997 - 2002.

HISTORICAL Capital - Category B: Distribution Plant details

Annual Capital Expenditures ($ millions)

	1997 Actuals	1998 Actuals	1999 Actuals	2000 Actuals	2001 Actuals	2002 Projected
Distribution Plant System Improvements	6.1	3.3	10.8	13.2	8.7	8.5
Distribution Risk Mitigation - Secondary Containment				0.7	0.1	0.5
Distribution Risk Mitigation - Seismic						
Distribution Risk Mitigation - Land Slippage				2.0		
Distribution Risk Mitigation - Meter Protection			2.0	3.1	0.1	
Total Nominal	**6.1**	**3.3**	**12.8**	**19.0**	**8.9**	**9.0**
Total Real	**6.5**	**3.5**	**13.5**	**19.6**	**9.0**	**9.0**

Note: Real totals in 2002 values.

In 2001 BC Gas commenced a Distribution Risk Assessment (“DRA”) program that reviews the health of the overall distribution system in detail. The program evaluates the distribution system to identify and evaluate specific risks. Due to the age and increasing size of the distribution system it is prudent to undertake such a formal risk assessment program. This program complements the annual planning cycle and is likely to identify that a higher level of upgrades or replacements is necessary.

Incremental funding associated with DRA has been identified primarily in Category C Capital budgets as well as Distribution Operating and Maintenance budgets. Specific Category B funding for DRA is also found in the risk mitigation section of the Category B forecast.

The distribution-related Category B expenditures are primarily one time projects which vary in size, complexity and duration. System improvements, required by customer growth, usually represent the bulk of these Category B expenditures. Growth-driven system improvements are forecast to be relatively low in 2002 at $3.2 million. However, large system improvements are planned for the Lower Mainland in 2003 (the next phase of Kootenay loop) and 2006 (the Fraser loop project), raising the total system improvements costs in these years to $12.9 and $14.0 million, respectively.

The Distribution Category B expenditures are driven mainly by the need to update and replace facilities to meet changes in code and to enable BC Gas to meet its customer requirements. The Distribution-related Category B expenditures for the past three years were approximately $13.6 million per year and over the 2003 to 2007 period average approximately $13.7 million ($13 million expressed in real 2002 dollars). The average of $13.7 million per year over the period 2003 – 2007 represents a prudent level, particularly when considered in terms of customer growth forecasts, the age of the system, provincial geography, recent high profile incidents, public and consumer expectations for safety and reliability, environmental and legislative impacts.

ii) Transmission Category B Capital Expenditures

The transmission-related capital expenditures within Category B include system capacity improvements to meet core customer growth, and expenditures related to ensuring safety and reliability of the transmission system.

A driver of Category B capital expenditures is the urbanization and the resulting increased activity around transmission rights of way. Work relating to the right of way in the Burns Bog area of Delta is an example. The right of way in the vicinity of Burns Bog carries two transmission pipelines that transport the majority of natural gas supply to Vancouver, Richmond and Burnaby. Landfilling activities on private properties adjacent to the right of way have caused unacceptable amounts of pipe movement and stress in a number of areas. The remedial actions required when these movements occurred have been very costly. In the period commencing in 1994, when the first serious damage to the Burns Bog area pipelines was detected, through December 2003, when required works on the affected pipelines are scheduled to be completed, approximately $9 million will have been expended to assess, monitor, and repair the affected pipelines. Approximately $2.0 million has been recovered through insurance. Future amounts may also be recovered through current legal proceedings although the outcome and amount that will be ultimately collected are uncertain. After extensive study by geotechnical engineering consultants, BC Gas has designed and is undertaking a program to prevent further damage to pipelines due to landfilling activities by acquiring additional right of way width in targeted locations of high risk. This effectively creates a buffer zone between landfilling operations and these critical pipelines to minimise the risk of further movement.

Capital expenditure to enhance the ability of critical BC Gas infrastructure to withstand seismic events has also been necessary. The risk of seismic activity over a significant portion in the Lower Mainland of British Columbia has become better understood during the past decade. BC Gas found it prudent to increase its investment in the upgrading of infrastructure to ensure minimal disruption of service and ensure public safety. Geotechnical hazards have become better understood and have required significant expenditures in a number of cases.

Included in the transmission-related Category B expenditures are upgrades to compressor stations and transmission pipelines, bridge and river crossings, and cathodic protection. The major projects included for 2003 expenditure are the $1.7 million Huntingdon No. 2 Station Capacity Upgrade project and the acquisition of additional rights of way around pipelines traversing the Burns Bog area at $1.2 million. The balance of the Category B projects cover a whole range of projects with values less than $1 million each.

The proposed level of expenditures is considered prudent, particularly when viewed in terms of the nature of the BC Gas system and its age. Much of the BC Gas infrastructure is over 40 years old and requires a significantly higher level of expenditures when compared to new facilities, in order to ensure that the Company’s commitments to public safety, environmental performance and its obligation to provide reliable service are met. BC Gas expects that ongoing Category B type of expenditures will remain relatively constant into the future. These expenditures are anticipated to be driven mainly by the need to update and replace facilities in order to meet changes to applicable codes and to enable BC Gas to meet its customers' requirements.

c. Category C - All Other Plant

Capital expenditures that were contained within Category C are those incurred in two major groups of activities, Information Technology ("IT") and Non-IT. Non-IT expenditures include costs associated with plant, labour, and equipment required for the alteration and replacement of gas mains, gas services, and pressure regulator stations; the acquisition or leasing of land; facilities including station buildings, facilities equipment; telecommunications infrastructure; specialized tools and equipment; and radio system upgrades. IT expenditures include costs associated with information technology hardware, infrastructure, and software requirements.

The designation of capital expenditures within Category A, B, C or D was useful during the 1998 - 2001 PBR period, but in the future these categories have less meaning since under a more comprehensive long-term PBR of the type discussed in this Application, the overall level of capital expenditures, and not the categorization of the expenditures, will be of greater consequence. In the past BC Gas has sought CPCN treatment for some IT projects, but does not intend to do so during a multi-year PBR of the type discussed under Tab G. The result is that the differentiation between IT projects that were in Category C, or were considered CPCNs, becomes blurred.

Some of the expenditures of the type that were included in Category C are one time projects, while other expenditures, such as main renewals, are ongoing based on historical levels. Expenditures within this Category are somewhat sensitive to general economic cycles, particularly load growth driven by customer additions and provincial energy economies. However, the majority of non-IT Category C expenditures is based on the overall size and age of the system and is not subject to major variation. Several drivers impact expenditures in Category C. Customer additions and load growth trigger new station work. Safety and reliability considerations result in service and main alterations and renewals. Planned activities of outside agencies such as municipalities, utilities, and developers result in lowering, moving and diverting the gas distribution system. Often, various authorities fund these expenditures with the credit accounted for in the CIAC account. Leak history and age of the gas distribution system also drives work characterized as Category C. Technological improvements also drive changes in tools, equipment, radios and furniture.

For IT projects, business needs and potential benefits arising from implementation of IT solutions are the prime determinants of IT capital expenditures.

For 2003 BC Gas forecasts Capital C expenditures of $30.0 million. Of the $30.0 million in total expenditures, 40% ($12.1 million) will be incurred in maintaining the integrity of the distribution infrastructure, acquiring real property and supporting facilities, upgrading communications and telemetry systems, and providing tools and equipment. The remaining capital, 60% ($17.9 million), will be incurred in the replacement, acquisition, and implementation of IT hardware, software, and related infrastructure. The expenditures are discussed further below.

The table below summarizes the forecast Category C spending for 2002-2007.

FORECAST Capital - Category C: All other plant

Annual Capital Expenditures ($ millions)

	2002 Projected	**2003** Forecast	**2004** Forecast	**2005** Forecast	**2006** Forecast	**2007** Forecast
IT Projects	17.0	17.9	18.0	19.3	20.6	21.1
Non-IT Projects	10.0	12.1	12.2	12.4	12.7	12.9
Total Nominal	**27.0**	**30.0**	**30.2**	**31.7**	**33.3**	**34.0**
Total Real	**27.0**	**29.5**	**29.2**	**30.1**	**30.9**	**31.0**

Note: Real totals in 2002 values.

The table below summarizes the historical annual Category C spending from 1997 to 2002; it does not include CPCN expenditures.

HISTORICAL Capital - Category C: All other plant

Annual Capital Expenditures ($ millions)

	1997 Actuals	**1998** Actuals	**1999** Actuals	**2000** Actuals	**2001** Actuals	**2002** Projected
IT Projects	11.4	16.3	17.5	17.8	18.6	17.0
Non-IT Projects	15.6	14.5	10.0	12.6	9.3	10.0
Total Nominal	**27.0**	**30.8**	**27.5**	**30.4**	**27.9**	**27.0**
Total Real	**28.7**	**32.8**	**28.9**	**31.3**	**28.3**	**27.0**

Note: Real totals in 2002 values.

i) Non-It Category C Capital Expenditures

The 2002 projected expenditure is $10 million for Non-IT projects. The forecast for 2003 is $12.1 million. This compares to an average of $12.4 million for years 1997 through 2001.

The Non-IT forecast is developed from historical expenditure levels and current requirements together with an allocation of funds for specifically identified projects and equipment. The forecast is developed in conjunction with Category C IT requests, such that projects are managed over a multi-year period to level out the total Category C expenditures.

The table below summarizes the Non-IT Category C forecast expenditures 2002-2007 on a per customer basis.

FORECAST - Category C: Non-IT Expenditures

Annual Capital Expenditures ($ millions)

	2002 Projected	2003 Forecast	2004 Forecast	2005 Forecast	2006 Forecast	2007 Forecast
Mains & Services Renewals/Alterations	5.4	6.5	6.5	6.5	6.5	6.5
Other Non-IT	4.6	5.6	5.7	5.9	6.2	6.4
Total Non-IT Projects	10.0	12.1	12.2	12.4	12.7	12.9
Customers (mid-year)	766,889	775,141	784,004	792,523	801,206	810,114
Total Nominal $/Customer	**13**	**16**	**16**	**16**	**16**	**16**
Total Real $/Customer	**13**	**15**	**15**	**15**	**15**	**14**

Note: Real totals in 2002 values.

The historical expenditure per customer for Non-IT Category C expenditures is summarized in the following table:

HISTORICAL - Category C: Non-IT Expenditures

Annual Capital Expenditures ($ millions)

	1997 Actuals	1998 Actuals	1999 Actuals	2000 Actuals	2001 Actuals	2002 Projected
Mains & Services Renewals/Alterations	4.8	5.9	6.4	3.7	3.4	5.4
Other Non-IT	10.8	8.6	3.6	8.9	5.9	4.6
Total Non-IT Projects	15.6	14.5	10.0	12.6	9.3	10.0
Customers (mid-year)	720,462	734,150	745,232	755,077	760,234	766,889
Total Nominal $/Customer	**22**	**20**	**13**	**17**	**12**	**13**
Total Real $/Customer	**23**	**21**	**14**	**17**	**12**	**13**

Note: Real totals in 2002 values.

The information in the tables above shows that BC Gas has reduced its per customer Non-IT capital costs and is forecasting lower per customer expenditures than they have averaged in the past.

The Non-IT forecast expenditures for 2003 consist primarily of mains and services replacements, together with smaller amounts for tools and equipment, new stations, telemetry and facilities expenditures such as telecommunications, structures, office furniture and equipment.

The forecast requirement for mains and services replacement for 2003 is $6.5 million. That level in nominal dollars is also forecast for the period through to 2007. From 1997 to 2001 the expenditures have ranged from $3.4 to $6.4 million ($3.8 to $6.7 million expressed on a real 2002 dollar basis). The forecast is based on average historical expenditure levels adjusted for anticipated remedial work identified through the Distribution Risk Assessment program. The DRA is expected to identify problem areas in the distribution system that will necessitate higher level of maintenance as well as replacements. Further ageing of the system, and the need to ensure adequate performance during seismic events, may result in increased costs beyond the current forecast. The alternative from a safety, reliability and cost perspective is to repair the leaks, rather than replace the main, which increases O&M costs.

The results of the annual leak survey and the documented history of leak occurrence drive the determination of the appropriate level of expenditure for mains and services replacement on any particular section of the distribution system.

Tools and equipment expenditures are another part of Category C. The forecast expenditures of $2.1 million for 2003 and beyond are associated with replacing and upgrading existing equipment, together with additions to provide for technological and methodology changes. Increased regulation and evolving work methods have led to additions in the area of accident prevention e.g. breathing apparatus. Maintaining the emergency response Service Quality Indicator and the effectiveness of that response and downsizing of the workforce has led BC Gas to outfitting more employees with broader tool sets, including pipe locators and temporary repair tools (squeeze-offs). In the Distribution area, changes in station components, such as gauges and telemetry, have driven the need to acquire up-to-date tools to measure and assess station flow indicators.

Included in the tools and equipment category are tool and equipment expenditures in the Measurement area related to design, purchase and installation of additions and enhancements to the existing Meter Proving Systems, Data Acquisition, and Meter Record Systems. These enhancements are necessary to ensure ongoing compliance with the *Electricity and Gas Inspection Act*.

Also included in the Non-IT costs are telecom expenditures that are forecast to be $0.5 million for 2003 and beyond. This expenditure level represents the ongoing additions, upgrades and replacements to standardize telecommunications in the Interior and Lower Mainland facilities. Expenditures in the area of radio systems are primarily for new repeater stations and equipment to support the BC Gas mobile radio system. There are still areas of the province with no mobile radio coverage. Compliance with new Industry Canada requirements for narrow band radio systems in the Interior has also driven expenditure forecast levels. Radio system upgrades are forecast to be $0.4 million per year for 2003 and beyond.

BC Gas operates and maintains a number of muster stations and field operating centres province-wide. Expenditures on these facilities have been within Category C. Periodically, these facilities require enhancements and upgrades. For example, BC Gas experienced several break-ins and thefts of property in recent years, and coupled with potential terrorist concerns, needed to re-evaluate and upgrade facilities security. Furniture and equipment requirements are driven by process, technology and organizational changes and are necessary to maintain operational efficiencies and meet industry standards. Forecast capital expenditures for facilities-related costs are $1 million per year for 2003 and beyond.

Expenditures for new regulator stations and telemetry are another part of Category C. They are associated with accommodating load growth, reallocation of existing load, system design changes, and providing adequate gas flow information to the gas control centre. These facilities play an essential role in maintaining correct system pressure and delivering an adequate and reliable supply of natural gas to the customer. Annual station/telemetry expenditures are forecast to be $1 million for 2003 and beyond.

BC Gas is taking a number of steps to manage, mitigate, and avoid Non-IT Category C costs. The mains and services replacement expenditures consume a significant portion of the Category C budget. BC Gas is experimenting with various alternative excavating techniques and trenchless technologies, as well as various alternative approaches to crew structure and job logistics. These endeavours are targeted at minimizing unit costs while maintaining high standards of system reliability.

As the Distribution system ages and grows, expenditures in Category C will increase. The pace of technological change continues to trigger expenditures to respond to and keep pace with industry and public expectations. Furthermore, the inflationary pressures from labour, materials and services continue.

ii) IT Capital Expenditures

IT spending is the second major classification of capital expenditures within Category C. Generally these expenditures have been made on new business applications using extensive information technology. Although some projects received approval through a CPCN process, many have been funded through the Category C capital budget.

IT expenditures can be categorized into four areas: new implementations for business units; technology sustainment and upgrading; application communication; and security.

A key driver of IT expenditures is that of changing business process needs. The business units of BC Gas seek to identify more efficient or effective processes as well as to permit the Company to preserve efficiencies that have been attained. If proposed new processes meet business case assessment requirements then BC Gas invests in information technology to automate these new processes. IT capital expenditures must also be made to allow the business units to comply with changing regulations and external requirements that demand compliance. The business applications are where many of the IT expenditures are made.

A second requirement for IT expenditures is the need to sustain and upgrade hardware and software. Keeping up with evolving technologies is a struggle for all companies. New infrastructure and new application versions have become common place throughout the IT industry. At times the turnaround from new to discontinued application versions can be as short as 18 months. Larger application vendors (e.g. GE Smallworld and SAP) have scheduled version updates that incorporate new changes and additional functionality to the application, incorporate correction patches into the core system and take advantage of improvements in infrastructure. Many software and hardware vendors are now abandoning older versions and withdrawing support as their new version becomes available. Consequently, continuous sustainment investments must be made to replace these older applications and technologies. This sustainment cycle also requires the upgrading and replacement of desktop computer technologies in order to operate more advanced versions of the software applications.

Communication between applications is essential to meet the increase in customer information demands. Software in this category, commonly known as Middleware, enables different applications to share data and present it on a single screen that will speed responses to customer requests and enable Company personnel to be efficient. Capital IT expenditures are regularly required to install and keep operational communications between applications.

The focus on IT security has increased steadily over the last three to four years. A dramatic shift in security threats began early in 2001. This is primarily due to the increased use of Internet e-mail functionality and the escalating threat of external hackers. The events of September 11th have increased the focus on those threats even more. The increased use of the Internet to support business processes requires additional investment in the protection of those processes and associated data. IT security must now be implemented with a depth model that uses many layers of differing protection but still offers the capability to support business requirements. Additionally, recent events have also caused all companies in North America to evaluate their Disaster Recovery Plan (DRP). Historically the Company did not have a DRP because operating information was paper based or intellectual capital of the workforce. Investing in enabling technology such as AM/FM, Integrated Resource Management and Predictive Maintenance increased the Company's efficiencies. These enablers allowed the Company to maintain the customer service levels and the integrity of the gas distribution system. Now that all key operating information is supported by an IT application a proper and evolving DRP is required.

The table below lists IT expenditures from 1997 to 2002. It is the Company's expectation that under a multi-year comprehensive PBR Plan the IT capital expenditures of the type that had been separately identified as CPCN expenditures in the 1998 - 2001 PBR Plan would be treated in the same manner as the IT capital expenditures that were part of Category C. To enable appropriate comparison, the information on both the Category C and CPCN capital expenditures is presented in this section.

Pathfinder and Program Mercury are excluded from the tables below because these projects formed part of the asset transfer from BC Gas to CustomerWorks. This exclusion normalizes expenditures and allows for a meaningful comparison over time.

HISTORICAL Capital - Category C / CPCNs : Information Technology

Annual Capital Expenditures ($ millions)

	1997 Actuals	1998 Actuals	1999 Actuals	2000 Actuals	2001 Actuals	2002 Projected
Category C	11.4	16.3	17.5	17.8	18.6	17.0
CPCNs *	4.9	17.6	0.7	6.4	3.6	6.7
Total Cat C/CPCNs*	16.3	33.9	18.2	24.2	22.2	23.7
Pathfinder		3.6				
Mercury			9.5	11.9	13.4	
Grand Total Nominal	**16.3**	**37.5**	**27.7**	**36.1**	**35.6**	**23.7**
Grand Total Real	**17.3**	**39.8**	**29.1**	**37.2**	**36.1**	**23.7**

* Excludes Pathfinder and Mercury

Note: Real totals in 2002 values.

In 2002 the Category C – IT expenditures are projected to be $17.0 million, which represents a reduction of $1.6 million from the previous year. When including the CPCN project (WMS/PM; discussed above under Major Projects), 2002 total expenditures are projected to be $23.7 million which is $11.9 million less than the prior year and the lowest level since 1997.

Looking forward, forecast IT expenditures for 2002 - 2007 are summarized in the following table.

FORECAST Capital - Category C / CPCNs : Information Technology

Annual Capital Expenditures ($ millions)

	2002 Projected	2003 Forecast	2004 Forecast	2005 Forecast	2006 Forecast	2007 Forecast
Category C	17.0	17.9	18.0	19.3	20.7	21.1
CPCNs	6.7					
Total Nominal	**23.7**	**17.9**	**18.0**	**19.3**	**20.7**	**21.1**
Total Real	**23.7**	**17.6**	**17.4**	**18.3**	**19.2**	**19.2**

Note: Real totals in 2002 values.

The $17.9 million of IT capital expenditures that BC Gas forecasts for 2003 is broken down as follows: $4.2 million is attributable to new implementations for business units, $5.0 million is for technology sustainment and upgrading, $4.9 million is for application communication and $3.8 million is related to security.

The $3.2 million increase in IT capital expenditures from 2003 to 2007 is primarily driven, other than inflation, by two significant requirements. The first is data security and integrity requirements that have recently seen significant cost increases with continued significant upward pressure forecast for the future. The second is the growth in cost to provide licensing fees for newly implemented applications and additional licensing fees for existing applications as they are rolled out to additional users.

Historical and forecast IT capital expenditures on a per customer basis are presented in the following tables.

HISTORICAL Capital - Category C / CPCNs : Information Technology - per customer

Annual Capital Expenditures ($ millions)

	1997 Actuals	1998 Actuals	1999 Actuals	2000 Actuals	2001 Actuals	2002 Projected
Total IT Projects - Cat C/CPCNs*	16.3	33.9	18.2	24.2	22.2	23.7
Customers (mid-year)	720,462	734,150	745,232	755,077	760,234	766,889
Total Nominal $/Customer	**23**	**46**	**24**	**32**	**29**	**31**
Total Real $/Customer	**24**	**49**	**26**	**33**	**30**	**31**

* Excludes Pathfinder and Mercury
Note: Real totals in 2002 values.

FORECAST Capital - Category C / CPCNs : Information Technology - per customer

Annual Capital Expenditures ($ millions)

	2002 Projected	2003 Forecast	2004 Forecast	2005 Forecast	2006 Forecast	2007 Forecast
Total IT Projects - Cat C/CPCNs	23.7	17.9	18.0	19.3	20.6	21.1
Customers (mid-year)	766,889	775,141	784,004	792,523	801,206	810,114
Total Nominal $/Customer	**31**	**23**	**23**	**24**	**26**	**26**
Total Real $/Customer	**31**	**23**	**22**	**23**	**24**	**24**

Note: Real totals in 2002 values.

The above tables show that BC Gas is forecasting an average IT capital expenditure for 2003 - 2007 of $23 per customer (expressed in real 2002 dollars) which is considerably lower than the average historical capital expenditure for 1997 - 2001 at $32 per customer (expressed in real 2002 dollars). This demonstrates the reasonableness of the BC Gas IT capital forecast.

While many of the basic applications required by BC Gas were installed or replaced during the past five years, providing a relatively modern set of business applications and supporting infrastructure, the Company must be in a position to develop new applications as significant changes emerge in its business. Under the Major Projects heading above two transmission-related applications are identified. Other parts of the Company are regularly identifying applications to meet legislative and regulatory requirements, and to enable the Company to provide safe, reliable and efficient service to customers.

Existing applications such as AM/FM and newer applications such as the replacement of the legacy WMS system with SAP have improved customer response, emergency handling, record keeping, and accessibility to gas system data. These applications will also enable the exchange of data in digital form so that the Company can participate in data sharing with other utilities, municipalities and government agencies. Upgrades to these systems, and the installation of new systems will be required as the Company moves into the future. As more customers and agencies are requesting and sending electronic data, future applications and infrastructure upgrades will be required to ensure data security and integrity. Also as business partners and customers change their business processes, other applications will allow customers greater convenience in gas nominations, trading and portfolio optimization.

The Company is assuming risks in its forecast of IT capital expenditures over the next five years. The forecast expenditures are at a lower level than overall IT capital expenditures in the past. The risks being assumed by the Company include:

- the potential change in regulation by the Oil and Gas Commission that is considering additional regulation to demonstrate the safety level of pipeline operations in response to recent pipeline incidents. This will require enabling technology such as electronic records for the Transmission business unit;
- a number of vendors (e.g. Microsoft) are restructuring their licensing model that will put upward pressure on expenditures;
- unknown changes in IT requirements over a multi-year PBR period as more business is conducted over the Internet. Greater internet connectivity will require more links with customers, marketers and other participants in the natural gas industry, greater exchange of information in electronic format, and greater security concerns.

The costs associated with the additional risks that the Company is taking in a long term forecast of IT expenditures cannot be predicted accurately. BC Gas is absorbing the risks while forecasting IT capital expenditures over the next five years at a level lower than in the past five years.

3. RATE BASE ADJUSTMENTS

The Program Mercury-related assets have been transferred to CustomerWorks pursuant to Commission Order G-29-02. In the Application materials the rate base for 2003 has been reduced by $32 million to reflect the transfer of assets. The rate base has also been reduced by $32.7 million to reflect increased cash flow resulting from the monthly billing of customers in the Lower Mainland (see Section H, Tab 5, page 1).

The rate base impact of the penalty arising from the 1998 - 2001 capital efficiency mechanism reached a maximum of over $10 million in 2001, and while being phased out pursuant to the mechanism, is forecast to result in $1.4 million of capital expenditures that were prudently incurred but upon which a return will not be earned in 2003. That decrease in rate base is taken into account in this Application (see section H, Tab 3, page 3.3).

In 2001 BC Gas entered into a Lease In, Lease Out (“LILO”) arrangement with the City of Kelowna. That arrangement was approved by Commission Order G-108-01. The Company expects to enter into similar arrangements with Vernon, Nelson, Prince George and a limited number of other municipalities. The rate base for 2003 has been reduced by $ 2.3 million to take into account the benefits that customers will receive from those transactions.

4. CONCLUSION

BC Gas has an obligation to serve current and future customers in a safe, reliable and efficient manner. For BC Gas to meet its obligations significant capital expenditures must be made each year. BC Gas has presented its forecast for 2003 capital expenditures and has also presented forecast capital expenditures for 2004 to 2007. The level of capital expenditures in the forecasts is reasonable and appropriate; and the forecasts should be accepted as a basis for 2003 rates and as a basis for a multi-year comprehensive PBR Plan.

D. OPERATING AND MAINTENANCE REQUIREMENTS

This section of the Application discusses the 2003 operating and maintenance ("O&M") expenses of BC Gas. O&M forecasts for 2004 – 2007 are provided as supporting information for the development of the multi-year PBR mechanism discussed in Section G. Historical actual (or projected) O&M expense information is also included in this section for each major business unit in the Company for 1997 - 2002. Additional schedules providing O&M information are included in Section H, Tab 9.

1. 2003 TOTAL O&M

O&M represents approximately 32% of the Company's total 2003 annual revenue requirement (excluding gas supply costs). BC Gas' O&M requirements are determined through a detailed business unit and departmental budgeting process. The total gross O&M requirements for 2003 are $183.6 million. This amount is net of any cross charges from BC Gas Utility for non-utility operations and to other BC Gas Inc. subsidiaries. The table below shows that the Company's total O&M requirements for 2003 are $192.9 million before adjustments for cross charges to BC Gas Inc. and continuing services provided to NRBs. These adjustments are described in further detail in Section E.

BC GAS UTILITY LTD.
RECONCILIATION OF 2003 TOTAL O&M TO UTILITY GROSS O&M
($000)

Line No.	Particulars	Total Utility
	(1)	(2)
1	Total Utility Business Unit O&M before Recoveries	
2	& Continuing Service charges	$192,930
3		
4	BC Gas Inc. - net 30% charge	(398)
5	BC Gas Inc. - non-utility	(633)
6	Centra	(96)
7	All other NRB's	(1,155)
8	Total Continuing Service Charges	(2,282)
9		
10	CustomerWorks Shared Services	(4,800)
11	Centra - Other Shared Services	(200)
12	Other Recoveries	(2,042)
13	Total Recoveries	(7,042)
14		
15	TOTAL GROSS O&M (Section H, Tab 9, Page 2.1, Line 39, Col. 3)	$183,606

The table shows that an adjustment to the gross O&M costs is also made for the recovery of costs for services provided by BC Gas to Centra. As a result of the acquisition of the Centra Gas companies by BC Gas Inc., Centra Gas and BC Gas are positioned to realize a number of operating synergies. Centra obtained certain corporate and other services from Westcoast Energy and its affiliates prior to the acquisition. Corporate services included various corporate governance activities in the areas of Human Resources, Finance, Treasury, Environmental Health and Safety, Investor Relations, Information Technology and Legal. In addition, a number of operating functions were performed by Westcoast such as gas supply management, gas control and SCADA .

BC Gas and BC Gas Inc. will have fully assumed the provision of these services by the end of 2002. BC Gas Inc. is in the process of finalizing contractual arrangements with Centra Gas and will utilize BC Gas resources based on the Company's Transfer Pricing Policy. BC Gas and its customers will benefit from the sharing of the costs associated with the provision of these services to Centra. In addition, BC Gas Inc. will recover a portion of its corporate costs from Centra that were formerly charged back to BC Gas Utility through a reduction in the corporate charge back to 70% from 80% in the past (this is discussed further in Section E).

O&M benefits that have been reflected in this application for cost recovery include:

- Gas control and SCADA - approximately $0.2 million annually; and
- Corporate services provided by Company employees - approximately $0.1 million annually.

In addition, Centra currently incurs gas supply core market administration costs in excess of $0.8 million per year. BC Gas anticipates that following the expiry of Centra's current outsourcing arrangement later this year, BC Gas can assume the majority of these functions and activities. Approximately $0.1 million will be recovered from Centra that will result in lower commodity costs to BC Gas customers. This amount is based on a proration of BC Gas costs. Centra will realize substantially larger savings from their current arrangements.

Additional synergies may be available in the longer term but would require further operational integration between the two utilities. To achieve this would require common technology platforms, process changes and other investments. For example, Centra may migrate from their Enlogix customer billing system to the CustomerWorks customer care environment ensuring all gas customers in British Columbia have similar customer care service. However, there are contractual impediments to acting on this in the near term and significant process changes would be required at Centra, BC Gas and CustomerWorks Inc. This Application reflects only those synergies available under the current operating environment.

The O&M level for 2003 applied for in this Application is lower than the sum of the individual budgets by $3.3 million. This amount represents the efforts of the Company to constrain its rates and maintain quality service. This lower total O&M also results in maintaining the operating costs below the O&M benchmark level extended to 2003 under the 1998 - 2001 PBR O&M formula. BC Gas believes that the internal O&M budget level represents a prudent and reasonable level of expenditure. BC Gas believes such an adjustment is responsive to concerns expressed by stakeholders and facilitates moving forward with negotiations on a multi-year regulatory settlement for 2003 - 2007.

The table below sets out the 2003 O&M requirements by business unit. For the larger business units, the O&M costs are broken out by the departments within the business unit in order to provide greater detail. The Company ensures that O&M funding is put to its best use and that the impact on customers' rates is minimized. The O&M expenditures that are forecast to be incurred by BC Gas in 2003, are reasonable, appropriate, and consistent with the trend of expenditures in prior years.

BC GAS UTILITY
OPERATING & MAINTENANCE EXPENSE
FOR THE YEARS 2002 TO 2007
SUMMARY BY BUSINESS UNIT
($000)

Line No.	Particulars	Projected 2002	Forecast 2003	Forecast 2004	Forecast 2005	Forecast 2006	Forecast 2007
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Distribution Operating & Maintenance	$21,010	$22,000	$23,334	$24,394	$24,972	$25,670
2	Emergency Management	5,582	5,792	5,948	6,122	6,301	6,486
3	Account Services / Fieldwork	5,735	6,315	6,501	6,708	10,083	12,406
4	Distribution Support	2,074	2,131	2,189	2,254	2,322	2,391
5	**Total Distribution**	**34,401**	**36,238**	**37,972**	**39,478**	**43,678**	**46,953**
6							
7	Operations Support	1,053	1,082	1,111	1,145	1,179	1,214
8	Engineering	4,961	5,326	5,462	5,614	5,770	5,931
9	Community, Developer and Aboriginal Relations	2,666	2,635	2,685	2,760	2,839	2,919
10	Measurement	3,111	3,488	3,628	3,781	3,937	4,100
11	**Total Network Development & Operations Support**	**11,791**	**12,531**	**12,886**	**13,300**	**13,725**	**14,164**
12							
13	Transmission	10,581	12,093	12,444	12,822	13,207	13,623
14	Gas Supply (excluding Core Market Admin Costs)	1,841	1,953	2,008	2,067	2,129	2,192
15	**Total Gas Supply & Transmission**	**12,422**	**14,046**	**14,452**	**14,889**	**15,336**	**15,815**
16							
17	Customer Care	42,101	47,777	48,661	49,815	50,742	52,160
18	Marketing & Others	10,080	10,118	10,367	10,647	10,934	11,229
19	**Total Marketing & Customer Care**	**52,181**	**57,895**	**59,028**	**60,462**	**61,676**	**63,389**
20							
21	Regulatory	3,584	3,670	3,761	3,862	3,965	4,072
22	Environment, Health & Safety	1,906	1,954	2,003	2,058	2,115	2,173
23	Supply Chain & Logistics	4,036	4,151	4,270	4,402	4,539	4,680
24	Facilities	5,882	5,999	6,231	5,961	6,136	6,315
25	Land Services	451	601	652	670	689	708
26	Legal & Risk Management	3,923	4,967	7,168	7,899	8,644	9,404
27	**Total RESSCL and Legal / Risk Management**	**19,782**	**21,342**	**24,085**	**24,852**	**26,088**	**27,352**
28							
29	CFO & Treasurer	8,585	9,703	9,979	10,286	10,604	10,931
30	Operations Finance	2,519	2,592	2,668	2,752	2,839	2,928
31	**Total Finance**	**11,104**	**12,295**	**12,647**	**13,038**	**13,443**	**13,859**
32							
33	**Information Technology Services**	**13,536**	**14,564**	**15,228**	**15,849**	**16,245**	**16,650**
34							
35	**CEO & President**	**9,316**	**9,380**	**9,552**	**9,846**	**10,045**	**10,251**
36							
37	**Human Resources**	**5,119**	**5,315**	**5,470**	**5,643**	**5,821**	**6,005**
38							
39	**TOTAL GROSS O&M**	**$169,652**	**$183,606**	**$191,320**	**$197,357**	**$206,057**	**$214,438**
40							
41	O&M Reduction		(3,300)	(3,300)	(3,300)	(3,300)	(3,300)
42							
43	**TOTAL GROSS O&M IN RATES**	**$169,652**	**$180,306**	**$188,020**	**$194,057**	**$202,757**	**$211,138**
44							
45	Less:						
46	Capitalized Overhead (Page 2.2)	(25,162)	(25,879)	(27,071)	(17,917)	(18,437)	(19,001)
47	Vehicle Lease	(1,779)	(1,833)	(1,888)	(1,945)	(2,003)	(2,063)
48	Fort Nelson	(571)	(581)	(591)	(603)	(615)	(627)
49							
50	**NET APPLIED-FOR UTILITY O&M**	**$142,140**	**$152,013**	**$158,470**	**$173,592**	**$181,702**	**$189,447**

2. 1998 – 2001 PBR O&M FORMULA

As a result of the withdrawal of its 2002 Revenue Requirements Application, BC Gas did not have a rate adjustment in 2002 to reflect increases in its O&M costs. For the three previous revenue requirement settlements covering 1994-1995, 1996-1997 and 1998-2000 (extended to 2001) the Commission approved the determination of gross and net O&M costs by a formula. While minor changes were introduced in successive periods the formula was generally as follows:

> O&M Expense = [Base cost x (1 + growth in customers - productivity) x (1 + inflation)] + Cost of Defined Required Incremental Activities ("DRIA")

By Order No. G-85-97 the Commission approved a three-year PBR Plan for the period 1998 to 2000. Subsequently Order G-48-00 approved a one-year extension to the Plan covering 2001. The Consolidated Settlement Document approved as part of the PBR Plan by the Commission states that:

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

When BC Gas filed its 2002 Application it provided both the budget driven O&M requirements and the O&M that would have been determined through the PBR O&M formula. Although Order No. G-85-97 does not apply to the current filing, for the purposes of continuity, it may be helpful to stakeholders to review the differences between the 2003 budget driven O&M requirements and the O&M that would have been determined using the former PBR formula.

The formula-based O&M costs used in the revenue requirement calculation include adjustments for exogenous factors. In establishing the Base Costs, the costs of the services provided under the B.C. Hydro Service Agreements were treated separately from other O&M costs. BC Gas has recognized the incremental costs associated with the repatriation of customer care function from B.C. Hydro in the formula-driven O&Ms.

The capital-related portion of the CustomerWorks charges has been added to the O&M formula reflecting the fact that these charges were formerly in BC Gas' cost of service as rate base return, depreciation expense and taxes.

The table below provides the calculations associated with carrying the O&M formula forward to 2003. The table indicates that the Company's 2003 O&M request is $4.2 million below the corresponding 2003 formula-based O&M. This comparison against the former O&M formula provides additional support for the reasonableness of the Company's 2003 O&M request. Customers benefit on an ongoing basis from the productivity embedded in the past PBR Plan and will also benefit on an ongoing basis from this additional $4.2 million decrease below the projected formula line.

BC GAS UTILITY LTD.

OPERATING & MAINTENANCE EXPENSE
O&M FORMULA FROM 1998 - 2001 PLAN ADJUSTED FOR CUSTOMERWORKS EXTRACTION
($000)

Line No.	Particulars	Test Year 2001	Formula-Based Cost 2002	Formula-Based Cost 2003
	(1)	(2)	(3)	(4)
1	Cost Drivers / Escalators			
2	Average No. of Customers			
3	Forecast	764,812	766,891	775,143
4	Projected	760,957		
5	Growth % (Based on 2001 Projected)		0.78%	
6	less adjustment to 2001 Forecast Growth		-0.51%	
7	Growth %		0.27%	1.08%
8				
9				
10	Productivity Improvement			
11	Factor (PIF)		0.00%	0.00%
12	Inflation (CPI)		1.90%	1.70%
13				
14	O&M Gross			
15	O&M Base Cost	$138,199	$141,208	$145,160
16	BC Hydro Service Agreements	10,898		
17	BC Hydro / Repatriated Customer Care		11,135	11,447
18	Total	149,097	152,343	156,607
19				
20	Additional Formula-Based O&M			
21	- DRIA's DSM / IRP	1,624	1,624	1,624
22	- OPEB (Net of Cash Payment)	4,075	4,621	5,467
23	- Incremental O&M - SCP & FV Compressor	2,000	2,000	2,285
24	- Repatriation of BC Hydro LM Customers Incremental Costs			
25	- Customer Care		3,159	3,514
26	- Bad Debt Experience Rate		1,254	891
27	- Monthly Billing		1,123	1,946
28	- Capital-related Portion of CustomerWorks Charges		3,793	8,980
29	Additional O&M - Total Increment	7,699	17,574	24,707
30				
31	Total Gross O&M	156,796	169,917	181,314
32				
33				
34	O'H Capitalized		16%	16%
35	O&M Capitalized (line 18 x line 34)		24,375	25,057
36	Total O'H Capitalized		24,375	25,057
37				
38	Total O&M Expense		$145,542	$156,257
39				
40	2003 O&M Request in this Application			$152,013
41				
42	Difference			$4,244

3. COMPANY-WIDE O&M COST DRIVERS

As with any operating company, BC Gas' O&M costs are subject to upward pressure over time. BC Gas has realized substantial efficiencies within its O&M cost structure over the last five years. These efficiencies have been achieved during a period of considerable change within the industry. BC Gas has managed its O&M costs in the face of unprecedented gas commodity cost increases, increasing customer expectations and technological change. BC Gas expects these cost pressures to continue and become more pronounced in their effect on BC Gas' resource requirements.

One of the most significant factors influencing BC Gas' O&M costs is inflation related to human resource costs. Human resource requirements are a key cost driver representing approximately 45% of BC Gas' total O&M costs. Changes in demographics will make attracting, training and retaining skilled workers increasingly more difficult and costly and will put pressure on the Company's benefits costs. Human resource costs are also under pressure due to legislative and regulatory changes relating to employee health and safety, environmental management and trades training.

BC Gas' O&M costs are also affected by non-labour related cost pressures. For example, a growing awareness of the environmental impact of greenhouse gas emissions, national voluntary compliance commitments and the potential ratification of the Kyoto Accord will also present increasing cost challenges to BC Gas. These are economy-wide factors that generally have an impact on all businesses operating in British Columbia.

In addition to these economy-wide factors, there are other drivers more specific to the natural gas utility industry and BC Gas' transmission and distribution system. One of the main drivers of O&M costs for BC Gas is the total number of customers and the size and the age of the gas distribution system. More operating and maintenance activities have to be performed as the size of the transmission and distribution system increases. Laws, code requirements, and accepted industry operating practices are also major drivers of the Company's O&M costs. BC Gas' standards and procedures incorporate the applicable Canadian Standards Association code and establish a balance between maintenance activity levels and acceptable risk levels.

These broad O&M cost drivers are discussed in the Overview to this section and where applicable there is an expanded discussion in the detailed business unit reviews that follow.

a. Customer Growth

O&M costs are incurred as a result of serving the existing base of customers as well as new customer additions. More operating and maintenance activities have to be performed as the system expands. These include administrative and operations activities such as customer care, customer communication, service line and meter inspection, leak survey, and credit management. These activities and the costs associated with providing these services generally increase proportionately with number of customers.

b. Codes, Regulations & Standards

Laws, code requirements, and accepted industry operating practices are major drivers of the Company's O&M costs. BC Gas' standards and procedures incorporate the applicable Canadian Standards Association code and establish a balance between maintenance activity levels and acceptable risk levels. The Company's standards are periodically reassessed and rewritten as required to ensure that the Company's natural gas transmission and distribution system is maintained to a high level. It should be noted that most codes and regulations set out only the minimum standards that should be met. Codes, regulations and standards are modified and upgraded on an on-going basis making it difficult to accurately predict the impact of possible future changes on O&M costs.

Regulations, codes and standards are in part a reflection of the public's expectations of an industry's minimum level of performance. These expectations change with time as new information or technologies become available. Potential changes to the *Gas Safety Act* could result in changes to line locate requirements, gas service inspections and work performed downstream of the meter set. These types of legislative revisions create risk to BC Gas in that the operating environment of the gas utility business may undergo some major changes. The impact of codes, standards and legislation on BC Gas' O&M costs are difficult to predict. Based on experience and current trends in this area, BC Gas expects that requirements of this type will only become more stringent and costly to manage over time.

c. System Age

The age of a utility's natural gas system is an important determinant of O&M costs. As a gas system ages, issues develop that require changes in operating practices in order to ensure that the system remains in a safe, reliable and efficient operating condition. The portion of the natural gas system now approaching the end of its estimated useful service life is likely to drive changes in BC Gas operating practices.

The Company through its predecessors dates back to the mid-1950s in the Interior and as early as 1860 in the Lower Mainland. While there is no pipe left in service from the 1800s, there are relatively large quantities of low-pressure piping left from the 1930s operating in Vancouver.

The tables below provide an age profile of BC Gas' transmission pipe and distribution mains. The age of the distribution service pipe shares a similar profile with distribution mains.

Transmission Pipe Profile

Age in Years	Total KMs
> 39	857
30 - 39	648
20 -29	322
10 - 19	180
< 10	407
Total	2,413

Distribution Main Profile

Age in Years	KMs PE	KMs Steel	Total KMs
> 50	0	2,284	2,284
41 - 50	0	2,021	2,021
31 - 40	4	2,599	2,603
21 - 30	13	3,357	3,370
10 - 20	2,058	1,685	3,743
< 10	4,053	354	4,407
Total	**6,128**	**12,300**	**18,428**

The level of expenditure required to operate and maintain these older segments to the required standard of safety and reliability has increased because of the need for selective pipe replacement or repair.

Utilities, regulatory authorities and the pipeline industry have become more aware of the need for improved management of the integrity of pipeline infrastructure as a result of a number of serious pipeline failures around North America in recent years. These high-profile incidents have raised the level of public concern and awareness of the potential ramifications of pipeline failures. System safety is a priority for BC Gas.

BC Gas had been focusing its system integrity resources primarily on the Interior Transmission System over the past few years as it was believed that there is a greater likelihood of integrity problems with that system. The Coastal Transmission System is now also benefiting from significant integrity-related work. Continued work is required throughout BC Gas' service area for both the distribution and transmission systems.

d. Human Resource Costs

Human resource costs represent the most significant portion of the Company's O&M. For 2003, total Company-wide human resource costs are forecast to be 45% of total gross O&M. These costs include direct labour and all benefits.

Factors that influence the level of human resource costs include:

- i) the number of employees;
- ii) regulatory requirements for trades training;
- iii) workforce demographics and competition for talent;
- iv) compensation; and
- v) employee benefits costs.

These major labour related cost drivers are reviewed in detail in the corresponding sections below.

i) Numbers of Employees 1997 – 2003

Between 1997 – 2003, the number of FTEs in the Company was reduced by 363, or by 21.4%. This reduction includes the transfer of 125 FTEs to CustomerWorks effective January 1, 2002.

The total workforce is forecast to be over 20% smaller in 2003 than it was in 1997. These reductions occurred as a result of the streamlining work processes, the implementation of technology, the consolidation of the customer care function, and the reduction and elimination of a variety of administrative support functions. Additionally, some reductions in the workforce are due to reduced work levels (associated with declining customer additions). These reductions are significant because they were achieved in a time of increased regulation in work practices, in addition to increased and more complex safety and health requirements.

Since 1997, the Company has reduced the number of executives from 12 to 10. This reduction was made in the interest of ensuring that the Company's senior management is streamlined and effective. In late 2001, the management structure of BC Gas was also reorganized to create a more efficient and customer focused utility.

Notwithstanding the reduced workforce, BC Gas has continued to meet its service quality indicator targets. The Company will continue to look for improvements in work processes to provide to customers safe, reliable, environmentally responsible and cost-effective service.

ii) Regulatory Requirements for Employee Training

Over the last five years a number of legislative and regulatory changes affected the Company's need to increase employee training. In the area of environmental management, the Company has been required to ensure employees are trained in such areas as spills response, environmental construction practices, and working in and around water. Requirements for increases in training for employee safety, include safety audits and inspections, Safety Committee training, the safe use of lifting devices and mini-excavators, and the prevention of violence in the workplace.

In view of recent increases in training expectations in the area of employee health and safety, BC Gas believes that the Workers Compensation Board will continue to expect additional mandatory training for safety committee members and for individuals who must use updated or new equipment in their work.

Other regulatory initiatives will also impact O&M expenditures as a result of potential changes in the mandate of the Safety Engineering Services ("SES") branch of the provincial government and the anticipated dissolution of the Industry Training and Apprenticeship Commission (ITAC). Safety Engineering Services currently qualifies welders and gas fitters.

Indications from the provincial government's Core Review of SES are that companies such as BC Gas may be required to provide increased competency assessment and training of gas workers to ensure provincial qualifying standards are met. The dissolution of ITAC affects the Company because it may be necessary to formally qualify all trades workers to a new government standard.

iii) Workforce Demographics and the Competition for Talent

According to the Business Council of BC, the demographics of the workforce (the ageing of "baby boomers" in particular), coupled with fewer people entering the labour market in B.C. and throughout Canada will put pressure on the ability to attract and retain people. Predictions made by the Business Council of B.C. of a severe shortage of trades skills in North America will impact BC Gas as members of the International Brother of Electric Workers ("IBEW") start to retire. In addition to trades, Statistics Canada has also identified looming shortages in the labour market for Engineers, IT professionals, and technicians.

The following aspects of the Company's current demographics are significant:

- 52% of employees are age 41 – 54;
- 15% are age 55 or more;
- 42% of the Company's IBEW workforce is eligible for early (reduced) retirement now; and
- within five years ~ 25% of the Company's IBEW may retire with unreduced pension.

The oldest employees are in technical areas – both in the IBEW and ("OPEIU"). For example approximately 47% of the IBEW workforce in Distribution and approximately 36% of the IBEW workforce in Transmission is over age 50.

Certain job categories where maintaining the safety, integrity and reliability of the gas distribution system is the prime requirement, face the highest risk. Currently, 65% of technicians and 34% of mechanics are over age 50.

Given the shortage of young people in the labour market that are entering trades and shops-related programs, it will be increasingly more difficult to recruit from this limited supply of talent. It is essential that the Company increase the time and resources dedicated to transferring knowledge to younger employees within the Company, and that BC Gas establish partnerships with educational institutions to ensure that BC Gas can access key skills as a greater portion of its current workforce begins to retire. In response to this challenge, the Company's operations departments incorporated funding for additional positions. These positions will ensure that essential knowledge is documented and transferred to new employees in the most critical areas.

The change in demographics will also affect the demand for management expertise. While voluntary turnover among employees in all affiliations is still low, voluntary turnover in the management category more than tripled between 1997 and 2000 when it increased from 3% to 9.3% per year. As the economy improves in British Columbia a number of employees in the management group will become even more attractive to other firms competing with BC Gas in the labour market, especially those employees with skills transferable to other industries; compensation for all labour faces pressure above inflation for the demographic reasons described earlier.

iv) Compensation

For the purposes of compensation, BC Gas' work force is separated into three primary groups: unionized employees represented by the IBEW and the OPEIU; and Management & Exempt ("M&E") employees, and Executives. While the details of the individual compensation plans vary between these three groups, the Company's compensation approach applies to all.

In 1998 BC Gas defined a compensation approach of establishing base salaries at the market median, and total compensation (base plus variable pay) targeted at the 75th percentile. In the case of Executives, total cash compensation is targeted at the comparator group median with opportunities for above-median compensation if Company performance warrants. Where performance is achieved or exceeded, total direct compensation (base salary, plus annual incentive, plus estimated annualized long-term incentive) is targeted at the 75th percentile of the comparator group.

For all employee groups, total compensation is benchmarked against a select group of local and national companies.

BC Gas has entered into five-year contracts with both the IBEW (2001-2006) and the OPEIU (2002-2007) that provide for 3% increases in wage scales over the term of the agreements. Consistent with these increases, the forecast used in this Application is based on an annual 3% increase in wage scales over the next five years for all bargaining unit, management and executive employees. The longer term contracts enable the Company to be able to attract and retain productive and skilled employees and are necessary to ensure

BC Gas keeps pace with the median of the market and remains an attractive employer for its skilled workforce.

v) Employee Benefit Costs Due to Changes in Provincial Medical Coverage

Changes in provincial government health care premiums and coverages will directly impact the costs of the Company's employee benefit plan. The recently announced 50% increase in Medical Services Plan (MSP) premium and other benefit cost increases results in an increased O&M cost of $570,000 (annual) to the Company. Changes in coverage in the MSP and Pharmacare programs are anticipated to increase claims by approximately 16% - 20%, or $148,000 to $185,000 annually. The reason for the projected increase in claims is that medical services that were previously provided by provincial government programs will, in several cases, fall on to the Company's Extended Health Care Program.

4. BUSINESS UNIT O&M REQUIREMENTS

The O&M expenses and additional resource requirements are discussed below for the each of BC Gas' operating, administrative and support business units. These include Distribution, Network Development and Operations Support, Gas Supply and Transmission, Marketing and Customer Care, Regulatory, Environmental, Health & Safety, Supply Chain & Logistics, and Legal & Risk Management ("RESSCL"), Finance, Information Technology Service, CEO and President, and Human Resources.

The amounts presented in this section reflect each business units' budget requirement; they have not been reduced to incorporate the $3.3 million reduction in O&M requested in this Application discussed above.

For historic comparisons of business unit costs, it has been necessary in some cases to restate historic O&M costs to reflect organizational changes that have occurred over the last five years. In order to facilitate comparability, the historical data for the Company has been restated to reflect the current organizational structure.

The forecast includes inflation calculated at 3% for labour, and 1.7% - 2.0% for non-labour items from 2002 - 2007. Contracts do not have inflation applied against them. The most notable contract in this regard is the Client Services Agreement with CustomerWorks. Forecast, bad debt expense has not been inflated for the purposes of this Application.

The O&M requirements reflected in this Application reflect the significant productivity savings achieved by BC Gas over the last five years. As discussed in the Application

Overview, BC Gas is one of the highest performers in its peer group of utility companies in terms of O&M efficiency measured by O&M cost per customer. These efficiencies were achieved through a substantive reduction in the Company's workforce as well as strategies such as process re-design and the cost-effective use of technology and IT systems. The business unit discussions below set out the anticipated challenges facing each department over the next five years and the measures being taken to mitigate their exposure to these items. Even with these measures, the Company's ability to drive further O&M efficiencies will be more difficult in view of these challenges and by virtue of the fact that the easiest, least cost and lowest risk opportunities have already been achieved. The five year business unit O&M forecasts provide a reasonable, conservative forecast of O&M requirements assuming annual revenue requirement determinations over that time period.

1. DISTRIBUTION

Distribution is the largest business unit or operating department in the Company in terms of number of personnel, capital and O&M cost structure. Distribution field workforces are distributed throughout the operating territory. Field workforces are trained and equipped with vehicles, appropriate tools and equipment to perform both the installation and the gas system operation and maintenance functions including responses to emergency calls.

Distribution O&M activities are focused on delivering a safe, reliable and cost-effective gas distribution system for residential, commercial and industrial customers. The forecast 2003 O&M cost for Distribution is $36.2 million. The majority of the operation and maintenance work to be done is known in advance and is planned throughout the year so that the utilization of the workforce is optimized. However, the field workforce is also needed to respond to emergency calls.

The operation and maintenance activities within Distribution can be categorized into four main functions or business processes. These four business processes are: Distribution Operations and Maintenance; Emergency Management; Account Services/Field Work; and Distribution Operations Support.

Distribution Operations and Maintenance includes scheduled and unscheduled operating and maintenance activities dedicated to mitigating operating risks and ensuring the safety and reliability of the distribution system. Activities include system damage repair, system inspection, leak survey, and preventative and corrective maintenance of equipment, valves, stations and meter sets. The primary cost drivers in this area are codes (Canadian Standards Association – CSA), regulatory requirements, age, standards and size of the distribution system.

Emergency Management includes the costs to support emergency response management in order to ensure public and employee safety. The costs supporting the Emergency Management function include first response to gas odour, fire and carbon monoxide calls, emergency prevention through public education and the costs associated with maintaining stand-by resources.

Account Services/Fieldwork represents work performed by Distribution staff relating to meter reading, premise calls, meter lock-offs, unlocks and pilot light relights, meter exchanges and other customer inquiries requiring a field workforce response. For example, a high bill complaint may require a visit to the customer's premise.

Distribution Operations Support includes technical services such as drafting and records management and other support related services such as distribution information technology systems.

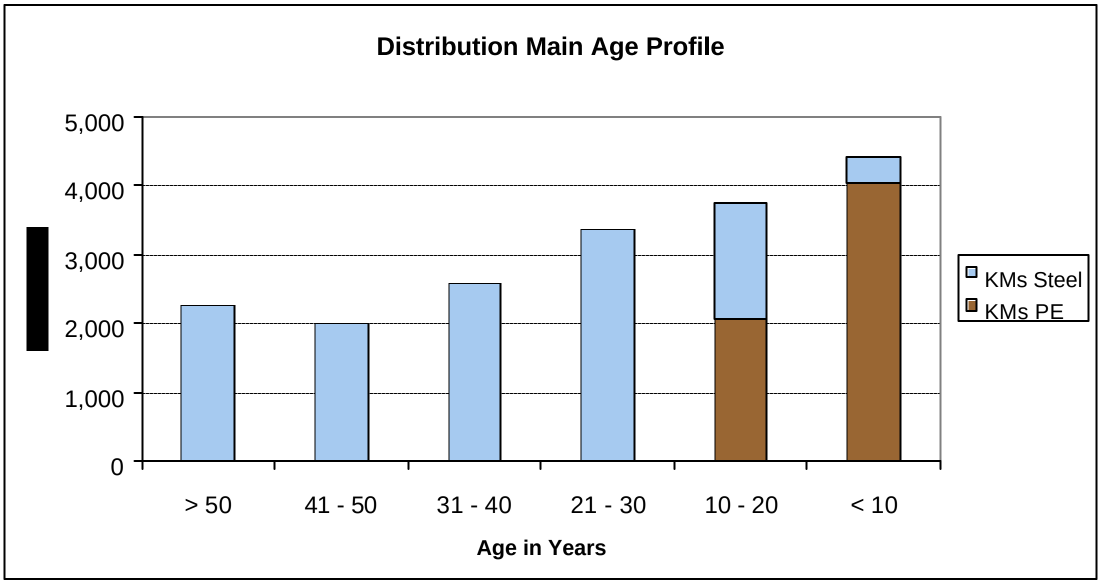
a. Distribution O&M Cost Drivers

As discussed in the introduction to the O&M section, two of the main drivers of O&M costs in Distribution are the total number of customers, and the size and age of the gas distribution system. The larger and older the system, more operating and maintenance activities must be performed. For example, a portion of all residential gas meters have to be changed each year, underground valves have to be maintained, gas regulator stations must be inspected and the underground gas system must be checked for leaks. Also, customers regularly call regarding concerns ranging from gas odour to bill inquiries. Laws, code requirements, and accepted industry operating practices are also major drivers of the Company's O&M costs. An example of the significance of changes in laws, standards and codes are the proposed changes to the *Gas Safety Act* legislation. BC Gas could be obligated under new legislation to provide a line locate service for the public. Currently BC Gas participates in the "One Call" program and provides excavators with location information, but does not provide field location of distribution plant except in rare instances where excavators have, after all reasonable attempts, been unable to locate the gas system.

Gas Safety Act changes could also involve changes in gas service inspections and work performed downstream of the meter set. The revisions are expected to be reviewed by the provincial legislature in late 2003 or 2004 and could drive significant phased-in changes for future operating years. The full extent and financial impact of the revisions will not be known with certainty for some time. An allowance for these potential changes, primarily in the area of line locates, has been made in O&M forecasts commencing in 2006.

In addition to customer additions and changes in codes and standards, the age of a utility's gas system is an important determinant of O&M costs. BC Gas has a program to replace its ageing distribution system, however as more of the distribution system ages, additional resources are required to upgrade the system.

The table below provides an age profile of BC Gas' distribution mains. The table shows that 37% of the distribution system is older than 30 years. The age of the distribution service pipe shares a similar profile with distribution mains.



In 2001, BC Gas initiated a Distribution Risk Assessment (DRA) program as a pro-active and prudent approach to make sure the appropriate steps are being taken to ensure that the gas distribution system remains safe and reliable as it increases in age. Piping system integrity is one of the elements of this review. The need for the DRA is driven in part in response to the increased public awareness of pipeline integrity issues resulting from a number of recent high-profile incidents.

While there have been no significant changes in regulation in Canada that require BC Gas to accelerate the risk assessment process, this could change. Recent regulatory changes being proposed in the United States regarding pipeline integrity could add significant cost if they were also mandated in Canada.

b. Forecast 2003 O&M for Distribution

The Distribution budget is stated in terms of the various resources used to deliver service, and shows the relative proportions of labour, vehicles and materials.

Distribution O&M by Resource ($ millions)

Resource Group	2003
Labour	26.1
Vehicles	3.3
Materials	4.1
Services	4.8
Recoveries	(2.1)
Total O&M	**36.2**

Over 70% of the O&M requirements of Distribution relate to labour costs, the balance being vehicles, materials and services net of recoveries (from third parties for system damages and the meter reading contract with CustomerWorks). The cost pressure faced by BC Gas in 2003 relative to projected 2002 budgets in the Distribution area are both in labour and non-labour costs.

The following table summarizes the total Distribution budget for 2003 broken down by major business processes.

Distribution O&M by Business Process ($ millions)

Business Process	2003
Distribution Operations & Maintenance	22.0
Emergency Management	5.8
Account Services / Field Work	6.3
Distributions Operations Support	2.1
Total O&M	**36.2**

Distribution Operation and Maintenance business processes make up the most significant cost item in the Distribution business unit. The Distribution Operation and Maintenance forecast for 2003 of $22 million consists of scheduled operations work of $12.2 million, scheduled preventative maintenance of $4.6 million and unscheduled corrective maintenance (repair) of $5.2 million. Labour and general inflation represent the largest cost pressure.

Another significant cost pressure results from gas cost changes that affects BC Gas' cost for own-use gas. The Company uses natural gas in its operations for transmission compressors and vapourizers at the LNG plant on the transmission system and line heaters in the distribution system. The line heater fuel gas funding required in Distribution for 2003 is $1.5 million. Due to the high volatility of gas commodity prices in the winter of 2000/01, the Company entered into a number of hedge transactions to secure minimum requirements of gas (i.e. warm winter levels) in the fall of 2001 for 2002. The balance was budgeted for at portfolio pricing levels adjusted for gas acquired under gas supply contracts that were structured on a 70/30 variable/fixed cost basis.

Because the upstream transmission pipeline tolls and 30% wellhead demand charges were fixed under the 70/30 contracts, BC Gas was able to access incremental gas requirements for own use gas at the variable cost (70%). However, these contracts have essentially expired so 2002 is the last year BC Gas can utilize the lower variable cost for own use gas.

The Distribution Risk Assessment (DRA) program undertaken in 2001 and 2002, and included in the Distribution Operations and Maintenance category, identified an increased need for maintenance activities. It is expected that the assessment portion of the DRA project will be substantially completed in 2004, leaving the repair/mitigation portion of DRA as a cost pressure for 2003 and forward.

There are several anticipated reductions to Distribution Operations and Maintenance business processes that offset some of the anticipated increases in costs. First, the DRA funding requirement will decrease by $0.8 million in 2003 as the program moves from the assessment stage to the repair mitigation stage over the next five years. The DRA funding need continues beyond those initial years but at lower levels than the first two years as the assessment phase is completed and the priority repairs/upgrades are addressed.

Second, BC Gas expects a $0.3 million protective coating program for stations, vaults and large commercial/industrial meter sets to be close to completion by the end of 2002. Discretionary activity has been reduced to accommodate significant mandatory non-discretionary O&M cost pressures, such as line heater fuel, Workers' Compensation Board ("WCB") compliance, and customer service work driven by higher commodity costs.

Lastly, BC Gas anticipates being able to use a leak survey contractor in 2003 to lower unit costs. BC Gas has had limited access to the contractor in 2002 in several geographic areas where layoffs occurred as IBEW contractual language prohibits using a contractor where employees are laid off. The savings associated with these items are reflected in the 2003 forecast.

Emergency Management business processes forecasts of $5.8 million in O&M for 2003. This amount consists of $4.0 million for emergency first response, and $1.8 million for emergency standby.

The Account Services/Fieldwork 2003 forecast of $6.3 million consists of scheduled meter exchanges of $4.4 million, bad debt management (lock-offs and unlocks) of $1.5 million and account services/high bill investigation of $0.4 million. The migration of Lower Mainland customer care activities in the latter half of 2002 is predicted to increase customer generated work activities in the Lower Mainland service area because once the bills are separated from B.C. Hydro, BC Gas will be responsible for the performance of gas customer activities. BC Gas currently benefits from the fact that in the Lower Mainland, when B.C. Hydro shuts off the electricity to a customer due to non-payment, gas appliances will generally not operate and therefore gas utility personnel have not been required to physically attend the premise to lock the meter off. Power is restored upon payment of the combined electric and gas bill. BC Gas will lose this benefit and the Company anticipates that this will cause an upward pressure on Distribution costs.

Current assessments indicate that gas meter lock offs in the Lower Mainland will increase over 200% from approximately 1,800 to 5,500 per year after repatriation. The $0.4 million incremental funding requirement is based on approximately 30 minutes per lock off plus 45 minutes for unlock/reactivates plus other customer generated work. Customer generated work activities also include meter re-reads and high bill investigations. The level of activity in this area can be expected to rise if there is any significant increase in customer rates caused by commodity price increase. The significant commodity related rate increases in 2000 and early 2001 caused a dramatic increase in 2001 customer generated work.

Business Support Services 2003 forecast of $2.1 million consists of technical services (drafting, records management) of $1.8 million and IT services (network services) of $0.3 million.

c. Historical O&M Expenditures, 1997 - 2002

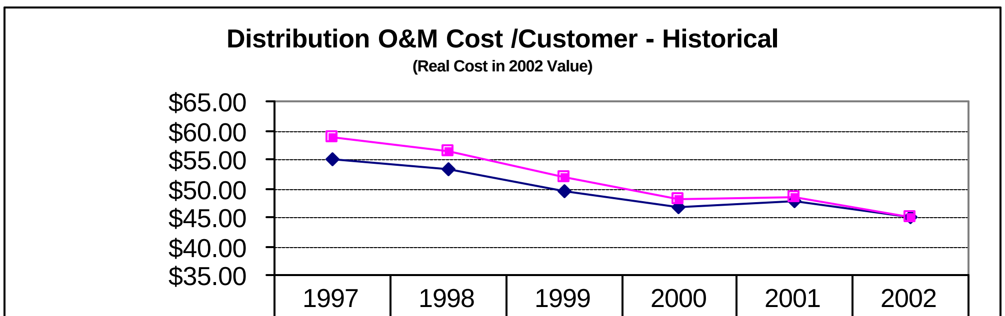
As noted earlier, the forecast $36.2 million O&M requirement for 2003 is $1.8 million higher than that projected for 2002. However, as shown in the table below, BC Gas has been able to reduce its cost of providing Distribution services over the last five years. Notwithstanding the proposed increase in Distribution funding for 2003, total O&M for Distribution will continue to be significantly less than the actual O&M costs incurred in providing the same services in 1997. The following table summarizes Distribution O&M costs in millions of nominal (actual) and real dollars.

Distribution's Annual O&M Expenditures ($ millions)

	1997 Actuals	**1998** Actuals	**1999** Actuals	**2000** Actuals	**2001** Actuals	**2002** Projected
Total Nominal O&M	**39.7**	**39.0**	**36.8**	**35.2**	**36.4**	**34.4**
Total Real O&M	**42.3**	**41.5**	**38.7**	**36.3**	**36.9**	**34.4**

Note: Real totals in 2002 values.

The savings achieved in Distribution are even more pronounced when expressed on a per customer basis. The historical O&M costs per customer dropped almost 24% in real terms as indicated in the chart below:



	1997	1998	1999	2000	2001	2002
Nominal Cost	$55.05	$53.17	$49.41	$46.57	$47.88	$44.86
Real Cost	$58.66	$56.49	$51.92	$48.03	$48.55	$44.86

The proposed 2003 Distribution costs are $47 per customer approximately equal to 2001 levels and substantially less than the 1997 levels. These efficiencies were achieved through the reduction in the number of full-time equivalent (FTEs) for the Distribution group from 861 in 1997 to 586 in 2002. The reduction of 275 positions represents a 32% reduction in the workforce. Throughout 1998 and 1999, staff reductions were made to Interior branch personnel, including office, sales and clerical staff, managers and material/merchandise handlers. The reductions were partially offset by the creation of the Customer Care call centre operation in Kelowna and the transfer of some accounting and administrative positions to the Surrey Operations centre. The benefits of the centralized Call Centre will continue through contracts with CustomerWorks.

In addition, Interior facilities, such as the field offices and operations centres, were closed or downsized. The Interior appliance merchandising program was discontinued together with the support infrastructure including merchandise marketing, sales and warehouse staff.

Further efficiency gains were achieved by eliminating over-the-counter bill payments in favour of encouraging more efficient mail and electronic payment methods. Over-the-counter bill payments were costly services for BC Gas to provide yet they were valued by only a small number of customers. Credit, collections and customer interface activities were also transitioned to the call centre in an effort to provide more consistent customer service and policy application, and longer operating hours. In early 2001, interior dispatch functions and new service application processing were centralized province-wide to the Surrey Operations centre.

A similar centralization and consolidation focus was initiated in the Lower Mainland. Essentially all administrative and operations process support functions have now been relocated to the Surrey Operations Centre. The key to this transition was new technologies and new facilities constructed at the Surrey Operations Centre.

BC Gas continues to rely on process re-engineering and information technology solutions to find further efficiencies. These have helped to reduce costs in Distribution. There are three major IT projects within Distribution, namely Automated Mapping/Facilities Management (AM/FM), Integrated Resource Management (IRM) and Work Management System/Preventive Maintenance (WMS/PM).

These technologies are necessary to support the workforce restructuring and productivity initiatives, and also replace outdated, maintenance-intensive systems that vendors no longer support. These systems are discussed in greater detail in this Application in Section C, Capital.

O&M reductions of approximately $2.0 million were realized in 2002 in Distribution as a result of these IT systems. These reductions were identified in business cases as benefits to be expected and are included in all cost projections. These benefits serve to offset some of the inflationary and upward pressures from rising labour/vehicle rates, commodity cost impacts and system integrity assessments faced by BC Gas in 2003 and beyond.

In order to continue to derive efficiencies BC Gas will further develop the ability to vary staffing levels and costs in proportion to activity levels. Enhancing the capabilities of employees to do more than one job type, and building the infrastructure that allows effective deployment of these employees through business initiatives, will allow BC Gas to decrease staffing in some areas. For example, drafting activities in 1997 were largely performed on a paper based system plotted by 25 drafters located in various regional Interior centres and two Lower Mainland facilities. Today, through a combination of technology, process improvement, facilities consolidation and declining capital, BC Gas' drafting activities are electronic based and maintained by 13 drafters located in the Surrey Operations Centre.

Technology also played a key role in enhancing the productivity of the dispatch activities of BC Gas. In 1997, BC Gas operated several dispatching groups in the Interior and the Lower Mainland. The Company's dispatch function was consolidated into one group (Integrated Resource Management) in 2002 through a combination of technologies and process improvements. These measures resulted in cost efficiencies both within the dispatch group as well as in field management. The IRM centre optimizes the use of field resources, schedules customer driven work, new install and maintenance work, and redeploys resources for emergency response.

The Lower Mainland and Interior field workforces have also been substantially reduced from 1997 to 2002. Technologies, such as Energy and WMS/PM, coupled with productivity gains, changes to operating practices and declining capital activity have contributed to these reductions.

For example, many of the customer service and operations workforce has changed from headquarter mustering to job-site and home mustering, thereby minimizing travel time. Technology changes allowed BC Gas to dispatch work electronically. Procedural changes are in some cases allowing one person to be sent to a job that may have required two persons in the past.

There were several other steps taken by BC Gas over the period that contributed to efficiency gains and risk mitigation. In the Interior, a decades old customer information system (CIS) was replaced with Energy, a new CIS. Implementation was primarily made necessary by Y2K concerns with the old technology and the centralization of several Interior office positions to a call centre environment in Kelowna. The change also impacted the customer service and meter reading activities where improvements in job tracking were made. Customer contact and repair work previously tracked manually and to a lesser extent on the previous CIS is now scheduled and tracked using a combination of Energy and IRM.

BC Gas negotiated a five-year contract in the fall of 2001, with the IBEW that provides both parties with price certainty for the long term, while at the same time significantly increasing the flexibility of the workforce.

An early retirement incentive, taken by 21 employees, was offered in late 2001. The majority of these employees were not replaced as IT benefits are expected to reduce the need for resources particularly in the preventive maintenance areas. The phased implementation of WMS/PM in 2001/2 is a major factor behind labour reductions, avoided costs and IT benefits realisation in 2002. The technology will eventually allow BC Gas to optimize maintenance schedules by re-allocating resources to high-risk preventive activities from low-risk activities. The vehicle costs have also been substantially reduced in step with the workforce reduction.

BC Gas is trying to lower the level of third party damage to the distribution system by being proactive in establishing a damage prevention program which targets municipalities and contractors for presentations on safety, cost to repair and construction practices. Focusing on reducing third party damages, also reduces the unscheduled response to emergencies which is disruptive to scheduled work and may result in missed customer appointments.

There continues to be efficiencies made in the support side of Distribution by standardization and centralization in the areas of clerical support, planning, dispatch, record keeping and administration functions. Through a combination of technologies and process redesigns, BC Gas continues to make progress in productivity gains. In 1997, for example, each Interior and Lower Mainland office had clerical employees responsible for issuing leak survey work to the field. Today, this seven-person group operates from the Surrey Operations Centre using AM/FM and SAP technologies to issue work to the field in a consistent regulated manner.

Many of these workforce reductions and efficiency measures were one-time opportunities made possible by the consolidation of facilities, particularly to the Surrey Operations Centre. It is unlikely that further facility changes will achieve the magnitude of reductions realized over the past PBR period.

Distribution has been able to deliver efficiencies without deteriorating service levels. In fact in many ways quality of service provided by BC Gas has improved. For example, customers receive consistent and rapid response to emergency enquiries/calls via a centralized Call Centre that is open eleven hours per day, five days per week. Currently, all after hour emergencies are handled by a 24-hour, seven-days-a-week, service centre capable of dispatching a first responder in minutes. Plans are underway to have the after hours emergency calls handled by the call centre, eliminating the need for the Service Centre.

d. Forecast O&M Expenditures, 2003 - 2007

Looking beyond 2003, BC Gas is forecasting the costs for Distribution activities to continue to face upward pressure. The forecast for O&M cost for Distribution from 2003 to 2007 is set out below.

Distribution's Annual O&M Expenditures ($ millions)

	2002 Projected	2003 Forecast	2004 Forecast	2005 Forecast	2006 Forecast	2007 Forecast
Total Nominal O&M	**34.4**	**36.2**	**38.0**	**39.5**	**43.7**	**47.0**
Total Real O&M	**34.4**	**35.6**	**36.7**	**37.4**	**40.6**	**42.7**

Note: Real totals in 2002 values.

Labour costs increases, are a significant portion of Distribution’s budget increase over the next five years. Also employee development and training is essential to ensure public safety, customer service and job knowledge. Depending on the nature of their position, office, field and managerial staff are required to take a number of mandatory training programs including emergency response, trade specific (i.e. welding re-certification), work activity specific (odourant handling, meter handling), leadership and environmental courses. Office and some field employees also receive training on multiple technology systems. Environmental legislation has also increased BC Gas’ operating and training costs in past years, and will continue to do so as legislation makes BC Gas’ business processes increasingly complex. The demographics of the BC Gas workforce will require additional training and employee development to replace cumulative years of knowledge and experience as a large portion of the workforce reaches retirement age. The “boomer bulge” is beginning to impact BC Gas, with the affect that critical knowledge and operating experience will be lost through retirement over the next several years. Recruitment and training costs will increase, although the precise level is difficult to predict.

An allowance for the cost associated with developing employees to replace those leaving is reflected in the five-year forecast O&M requirements. Specifically, additional incremental funding of $0.4 million per year, commencing in 2004, provides for six additional full time equivalent employees (FTEs), three in management and three in field positions. A significant portion of BC Gas' management and field workforce is over 50 years of age with substantial working years behind them. The additional FTEs are expected to provide for routine succession planning over the PBR period as well as provide for significant field workforce training, including additional "operator" qualifications, which are starting to become the norm in the North American trades industry.

However, as demonstrated in the table below, even with the addition of these employees, the forecast customer to employee ratio is expected to continue to improve over this time frame. This improvement mitigates some of the cost pressure discussed above.

Distribution Customer to Employee Ratio

	2002	2003	2004	2005	2006	2007
Average Customers	766,889	775,141	784,004	792,523	801,206	810,114
Employees (FTEs)	586	601	607	607	607	607
Customer to FTE Ratio	**1,309**	**1,291**	**1,293**	**1,307**	**1,321**	**1,336**

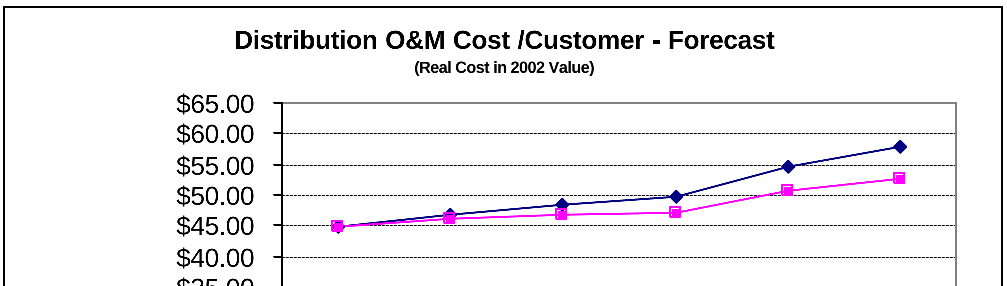
The Distribution system age and reliability will continue to be an increasing issue as more pipe reaches the end of its service life. The Distribution Risk Assessment (DRA) will identify the areas that need attention and the repair work that follows DRA should ensure a secure, reliable and cost-effective distribution system without undue risk.

Sustainment of IT benefits substantially realized in 2001, will be key to BC Gas being cost-effective. Declining capital (mains, services, and meter activity) together with process improvements have, in combination with the IT technologies, allowed BC Gas to achieve substantial operating efficiencies and capital expenditure reductions. The long term effectiveness of the IT technologies will be tested as capital activity rebounds.

Other significant challenges will be the policy changes driven by outside authorities, most importantly, the provincial *Gas Safety Act*, WCB compliance, environmental standards and Canadian Standards Association. With respect to the *Gas Safety Act*, Distribution has included $3.1 and $2.0 million respectively in 2006 and 2007 O&M forecasts, primarily in anticipation of changes in the area of field locates, quality assurance, administration and inspections on gas appliances downstream of the meter set.

Security of distribution facilities has become a high-profile issue since the terrorism activities on North American soil. Distribution Systems are potential targets, and precautions must be taken to mitigate risk for distribution facilities and infrastructures. An increase in O&M cost for Distribution of $0.1 million has been included for operations security.

The forecast O&M levels for Distribution indicate that the real cost per customer over the forecast period will continue to remain below the 1997 level of $59. The table below indicates that notwithstanding the pressures outlined above, BC Gas will be able to maintain its Distribution costs at or below $53 over the forecast period. The values for 2002 – 2007 are summarized in the following table:



	2002	2003	2004	2005	2006	2007
Nominal Cost	$44.86	$46.75	$48.43	$49.81	$54.52	$57.96
Real Cost	$44.86	$45.97	$46.78	$47.17	$50.61	$52.75

2. NETWORK DEVELOPMENT AND OPERATIONS SUPPORT

The Network Development and Operations Support business unit (“ND/OS”) provides services in support of the Company’s operating groups. ND/OS is comprised of four departments: Engineering; Community, Developer and Aboriginal Relations; Measurement; and Operations Support. These departments are described further as follows:

- The Engineering department provides three categories of services: a) engineering governance; b) engineering design, project management and support services; and c) corrosion control, instrument control shop and project planning.
- The Community, Developer and Aboriginal Relations department is responsible for developing and maintaining relationships with key stakeholder groups, including municipalities; builders and developers; and communities and Aboriginal Bands. These stakeholders receive consistent and focussed communication regarding gas transmission and distribution system issues from a single-point of contact within BC Gas.
- The Measurement department is responsible for maintaining the accuracy of metering devices for BC Gas, as well as providing energy consumption data to large commercial and industrial customers. This responsibility is divided into three main areas: a) maintenance of meters installed at customer locations; b) the procurement and certification of new meters; and c) the provision of energy consumption data to large commercial and industrial customers.
- The Operations Support department manages and administers the ND/OS business unit functions, including the management of the municipal franchise agreements. This department is also responsible for overseeing process improvement initiatives. A key process improvement initiative currently being carried out is the Order Fulfillment project, which involves reviewing and redesigning all business processes used to attach new customers to the distribution.

The Order Fulfillment initiative is being undertaken in conjunction with the Work Management System (“WMS”) technology replacement project. This process review and re-design is being applied from the point of initial customer contact through to the final installation of a meter. The goal of this project is to create a process that is significantly more customer friendly and one that ensures efficient, clear and consistent service. BC Gas expects this to improve customer satisfaction by making it easier for customers to do business with BC Gas. The new process will provide a single point of contact for customers within the Company. The BC Gas representative with whom a customer makes contact will have all of the necessary knowledge and access to information required to process a request and move the work to the field as quickly as possible. In addition, this re-designed process will allow the Company to commit to earlier installation promise dates. Another major benefit expected from this initiative is that the cost of adding new customers to the system will be better understood as a result of capturing the full cost of new additions. This benefit will provide the Company with the information needed to optimize opportunities to capture economic new load.

a. Cost Drivers

Several cost drivers affect the level of O&M expenditures within the ND/OS business unit. The main cost drivers are the growth, scale and age of the distribution system. As the number of customer additions increases there is a requirement for more activity to analyze and design new system additions to accommodate increased load and to maintain the hydraulic integrity of the existing system. New customer additions also drive the requirement to purchase and process increasing numbers of meters. As the gas system ages, there is also a need to evaluate system integrity and design system upgrades to meet regulatory requirements and ensure the continued safe and reliable operation of the system. The need to maintain and expand existing rights of way for the transmission and distribution system requires BC Gas to negotiate agreements with landowners, including First Nations and to undertake public consultation activities. On-going communications with community stakeholder groups throughout the lifecycle of major projects is also required.

b. Forecast 2003 O&M Expenditures for ND/OS

The ND/OS business unit forecasts an O&M requirement of $12.5 million for 2003. The $12.5 million O&M requirement for the ND/OS business unit represents a $0.8 million increase over the 2002 level. The following table breaks out this requirement by department.

NDOS' Annual O&M Expenditures by Department ($ millions)

Department	2003
Engineering	5.3
Community, Developer & Aboriginal Relations	2.6
Measurement	3.5
Operations Support	1.1
Total O&M	**12.5**

Engineering

The Engineering department forecasts $5.3 million in O&M expenditures for 2003. These resources are required to provide project management and design solutions which meet all applicable codes and regulations and which ensure safe, reliable operation of the gas distribution system. These expenditures are primarily related to $3.3 million in compensation costs for this department's staff. The remaining $2.0 million of non-labour resources is required for materials such as odourant and services such as contractors and consulting.

In 2000, a dedicated engineering governance function was created within the Engineering department to clarify the roles and responsibilities of Professional Engineers with respect to engineering design, and construction and maintenance activities. This function ensures that all areas of activity within BC Gas comply with the *Provincial Engineers and Geoscientists Act*. Activities include the development and publishing of design and construction standards and guidelines, code interpretations and compliance evaluation, technical audits and participation in regulatory and industry codes and standards development. These activities are necessary to ensure that BC Gas is cost effective when undertaking new designs and construction and that BC Gas meets regulatory safety codes and standards and account for approximately $0.4 million of the department's O&M requirements.

Approximately $1.5 million of forecast O&M relates to the engineering design and project management functions which provide support to other operational areas within the Company. The majority of the support activities focus on existing facilities, including the undertaking of problem and failure investigations, risk analyses, regular delivery station capacity reviews, maintenance and repair support, policy and procedure reviews, vegetation control programs, specialized drafting services, and records management for facility drawings and projects. A portion of the funding is also required for such project management activities as preliminary feasibility / options studies and cost estimates. In some cases Engineering employs consulting or contract engineers in order to meet specific needs. These activities are carried out to ensure the safety and reliability of the system.

The responsibilities for corrosion control, the instrument control shop and project management are also within the Engineering department and account for approximately $3.3 milion of the O&M requirement. Corrosion's prime function is to ensure safe and reliable service to our customers by inspecting and maintaining the integrity of cathodic protection on all of BC Gas' steel transmission and distribution lines. This responsibility includes inspecting and maintaining the integrity of BC Gas’ odourization program, the LNG plant and gate stations instrumentation and controls, and other instruments used by operating personnel.

Community, Developer and Aboriginal Relations

The O&M required in 2003 for implementing the responsibilities of this group totals $2.6 million. The community and aboriginal relations funtion accounts for approximately $2.3 million of the department’s O&M forecast, and is made up of $1.8 million for labour and $0.5 million for non-labour costs. The builder and developer relations activities within the department comprise approximately $0.3 million of the O&M requirement.

Community Relations ensures that customers are consulted, informed, and have an opportunity to provide feedback about BC Gas’ operations in their area. As a result, this group provides value to BC Gas by managing risk through the development and enhancement of relations with customers in communities served by BC Gas.

BC Gas has a legal obligation to consult with all Bands whose lands could be affected by BC Gas’ operations. The aboriginal relations group provides value to BC Gas by managing risk through the building and enhancement of relations with First Nations. This work is completed with Chiefs and their Councils, members of Bands whose lands are crossed by BC Gas pipelines, First Nations governments who have rights and title interests in Crown land crossed by BC Gas pipelines, and Tribal Councils.

The developer relations component is responsible for developing and maintaining key account relationships with architects, engineers, developers and large project builders providing utility, system design and appliance, information, and assistance. As well, contact with residential homebuilders is maintained through seven Canadian Home Builder Association chapters.

Measurement

ND/OS forecasts that the total O&M for Measurement services is $3.5 million, and is comprised of $2.8 million for labour and $0.7 million for non-labour costs.

Measurement is responsible for maintaining the accuracy of metering devices according to the specification issued by Measurement Canada, as well as providing energy consumption data to large commercial and industrial customers. This responsibility is divided into three main areas. The first involves the maintenance of meters installed at customer locations. A portion of these meters is recalled annually for maintenance and verified for measurement accuracy. Those meters that are verified as accurate according to Measurement Canada's specifications are certified and made available for re-installation at customer locations. The second responsibility involves the procurement and certification of new meters to replace those scrapped and those required for customer additions. Finally, Measurement also provides energy consumption data to large commercial and industrial customers who require time interval data to help better manage their energy use requirements.

By virtue of an approved Quality Assurance Program, the Measurement department of BC Gas is accredited by Measurement Canada to provide meterology services to BC Gas. Surveillance audits are regularly performed by Measurement Canada and BC Gas' ISO-9002 registrar to ensure ongoing compliance with standards and quality assurance procedures.

Operations Support

The Operations Support group incorporates the business unit management and administrative functions. Of the total $1.1 million related to this area, $0.9 million is related to compensation costs and includes management salaries, as well as the union and non-union incentive pay for the business unit. The remaining $0.2 million includes non-labour expenses such as travel and administrative expenses.

c. Historical O&M Expenditures, 1997 - 2002

Over the period 1997 through 2002, the O&M expenditures for what is now the ND/OS group have decreased from $15.0 million to $11.8 million in terms of nominal dollars. This change represents a decrease of approximately 21%. In real terms, the decrease is $4.2

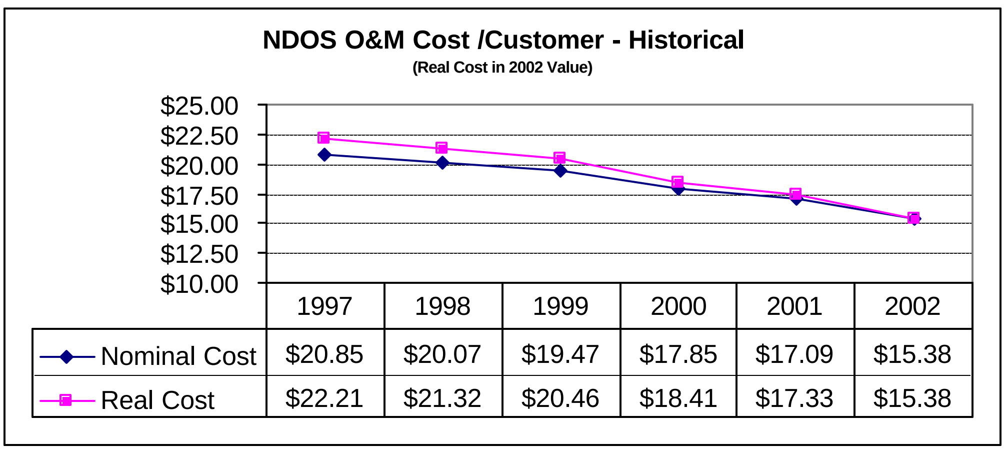
million, or approximately 26%. The table below sets out the O&M for the group for 1997 through 2002.

NDOS' Annual O&M Expenditures ($ millions)

	1997 Actuals	1998 Actuals	1999 Actuals	2000 Actuals	2001 Actuals	2002 Projected
Total Nominal O&M	**15.0**	**14.7**	**14.5**	**13.5**	**12.0**	**11.8**
Total Real O&M	**16.0**	**15.6**	**15.2**	**13.9**	**12.2**	**11.8**

Note: Real totals in 2002 values.

A review of O&M costs per customer provides another view on historical resource demands. The chart below shows that real O&M costs per customer have decreased from $22.21 in 1997 to $15.38 in 2002. This change represents a decline of 31%.



d. Forecast O&M Expenditures, 2003 – 2007

The following table summarizes ND/OS forecast O&M requirements for 2003 – 2007. The projected expenditures for 2002 is provided for comparative purposes.

NDOS' Annual O&M Expenditures ($ millions)

	2002 Projected	2003 Forecast	2004 Forecast	2005 Forecast	2006 Forecast	2007 Forecast
Total Nominal O&M	**11.8**	**12.5**	**12.9**	**13.3**	**13.7**	**14.2**
Total Real O&M	**11.8**	**12.3**	**12.4**	**12.6**	**12.7**	**12.9**

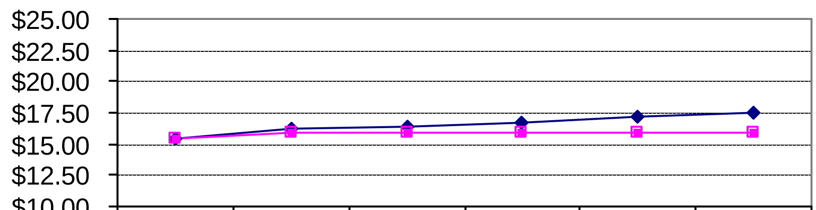
Note: Real totals in 2002 values.

The primary driver of the cost increases over the next five years is the forecast number of customers, which is anticipated to increase by approximately 5% in the same time period. This change is reflected in forecast O&M expenditures, they are expected to increase by a real 5%, or by $0.6 million between 2003 and 2007.

The O&M costs per customer are reflected in the following table that shows O&M per customer, in real terms, is expected to increase only slightly from $15.90 to $15.91.

NDOS O&M Cost /Customer - Forecast

(Real Cost in 2002 Value)



	2002	2003	2004	2005	2006	2007
Nominal Cost	$15.38	$16.17	$16.44	$16.78	$17.13	$17.48
Real Cost	$15.38	$15.90	$15.88	$15.89	$15.90	$15.91

Over the course of the next five years, the major challenges the ND/OS Group will face are as follows:

- changing customer demands fuelled in part by technology development and the major trend towards the use of the Internet to give customers access to retail products and services and instant access to information. This will drive the need to continuously refine the business processes involving external customer transactions;
- changes in the regulation of gas pipelines, distribution systems, gas measurement devices and the activities of engineers working on these systems or devices; and
- changing demands on the part of Aboriginal Bands, municipalities and the expiry of long standing franchise and operating agreements.

In addition to these challenges, it is expected that over the next five years, ND/OS will expand the Order Fulfilment Initiative from new mains and services to all other service requests received from customers. It is anticipated that this will include requests such as high bill inquiries, service alteration requests, and tariff change requests. The objective will be to continue to drive improved levels of customer service.

The risks that ND/OS are expecting to manage over the next five years that have not been included in the above forecast of O&M expenditures include:

- provincial government downloading of regulatory responsibility with respect to the *Pipeline Act* would force ND/OS to significantly increase its O&M spending on Engineering Governance. The Provincial Government has announced its intention to move service delivery currently provided by Gas Safety Branch to the private sector by 2005. This could trigger significant O&M increases for Engineering as was the experience for gas utilities in Ontario when this function was outsourced to the private sector;

- significant changes to the existing Municipal Charters currently being developed by the Provincial Government could trigger increases in O&M spending with respect to the Community, Developer and Aboriginal Relations department if the charter changes grant municipalities broader powers associated with taxation or land use; and

- the installation of major new pipelines will increase O&M costs associated with odourant purchase and conditioning of the new pipeline in addition to the costs of completing corrosion surveys in accordance with regulatory requirements.

In summary, ND/OS ensures that the operating standards and governance programs exist to meet all regulatory requirements and that through the provision of technical support services, the system will continue to operate safely and reliably. ND/OS also adds value to the day to day operations of the system by designing business processes such as Order Fulfilment, which seek to continuously improve customer and stakeholder satisfaction and which allow for profitable and sustainable growth of the system through new customer additions. The provision of these services has been rationalized and centralized within ND/OS to ensure cost effective service delivery. Uncertainties with respect to regulatory changes will, however, create future financial pressures for the ND/OS group.

3. GAS SUPPLY AND TRANSMISSION

Gas Supply and Transmission (GS&T) manages the gas supply and transmission assets. In order to meet its business demands, GS&T is organized into the following main business segments:

- Gas Supply provides the gas supply management function, which encompasses most elements of the gas merchant role. This function ensures that there are reliable and secure supplies of natural gas for the Company's customers at an optimum cost. Costs for this group are funded by utility O&M and Core Market Administration. Core Market Administration costs are not part of the Company's O&M for this Application. The separation of functions performed to funding is explained below.
- Transmission provides the transmission asset management function that ensures that the BC Gas transmission system can deliver gas from interconnecting pipelines or the Tilbury LNG facility to the gate stations operated by Distribution in a safe and reliable manner.

a. Cost Drivers

Cost drivers for Gas Supply have been and will continue to be related to the deregulation and restructuring changes of the North American energy market. In the Pacific Northwest, these challenges are amplified by regional infrastructure constraints. In this environment, gas supply management, to ensure optimum commodity cost for customers, requires additional transactions and increased monitoring of price risk exposure, credit risk exposure and other business risks. Ongoing reviews are made to ensure that the necessary effective and efficient processes are in place and that costs are kept in line with the value delivered.

Cost drivers for Transmission relate largely to the need to maintain an ageing infrastructure in operating condition to ensure safe and reliable gas delivery under increasingly more complex and stringent code requirements. Diligent effort is made to manage these at a reasonable cost while not jeopardising safety and reliability.

b. Forecast 2003 O&M Expenditures for Gas Supply and Transmission

The following table summarizes the components of the 2003 O&M forecast by business segment. Explanations of changes compared to 2002 are detailed by business segment later in this section.

GS&T's O&M by Resource ($ millions)

Department	2003
Gas Supply	
Labour	1.5
Contractors & Services	0.3
Other	0.2
Subtotal	**2.0**
Transmission	
Labour	6.1
Contractors & Services	5.5
Other	0.5
Subtotal	**12.1**
Total O&M	**14.1**

c. Gas Supply

The Gas Supply group is responsible for the acquisition and transport of natural gas for the firm and interruptible customers of BC Gas. The key objectives of the group are to:

- provide natural gas supply to firm and interruptible customers on the BC Gas distribution system;
- provide intra-day balancing supply to stabilize the pressures on the BC Gas distribution system;
- facilitate all gas scheduling and nominations on BC Gas and third party transmission systems and on the BC Gas distribution system;
- optimize the value of the natural gas supply portfolio for the benefit of customers on the BC Gas system; and
- manage relationships with upstream pipeline companies (Duke, TCPL) to the benefit of BC Gas' customers.

As part of the gas supply activity, an Annual Gas Contract Plan is produced and filed with the Commission. This plan outlines BC Gas' strategy to manage its supply portfolio in order to meet the needs of its core customers through contracting for an optimized mix of commodity, storage and transportation. It details a one-year plan for gas procurement activities and as well addresses the longer term (three to five years) to provide an indication of longer term contracting or marketplace changes being anticipated.

At present the supply portfolio includes 13 baseload contracts with 10 suppliers for approximately 173 TJ per day of energy delivered off the Duke pipeline, as well as two baseload contracts totalling 35 TJ per day of Alberta supply utilising the TransCanada PipeLines (B.C.) pipeline. BC Gas purchases summer seasonal supply under five contracts with four suppliers for up 90 TJ per day, winter seasonal supply with various term dates under 40 contracts with eleven suppliers for up to 292 TJ per day and has two 15 day peaking contracts from two suppliers totalling approximately 115 TJ per day. BC Gas also utilizes five storage facilities to provide up to 388 TJ per day of peak day supply. The combined portfolio of baseload and seasonal contracts have expiry dates ranging from one to four years, while peaking and storage contracts range in term from one to 13 years.

The group also performs commodity price and volatility management and credit risk management activities on behalf of the company's customers. An annual commodity price risk management plan is filed with the Commission that lays out guidelines and processes for the management of commodity price volatility. Once approved by the Commission the group implements the plan.

The credit risk management function involves developing a credit risk management plan and tracking the credit exposure to various gas suppliers and marketers and ensuring that credit risk exposure is prudently managed. For example, during the recent Enron meltdown, BC Gas, through this proactive credit management approach was able to ensure that its customers did not experience any losses as a result of the default by the largest counter-party in the natural gas business.

i) Gas Supply Cost Drivers (O&M and Core Market Administration)

Gas Supply is facing cost pressure relating to business changes occurring in the North American Energy Market. Substantial and sustained supply and demand imbalances, particularly in the western portion of the continent, resulted in dramatic price escalation in the markets for electric power and natural gas during 2000/2001. The dramatic swings experienced in gas costs during 2001 have diminished somewhat during 2002 but gas price volatility is expected to continue into the future. Key business changes and pressures include:

- increasing deregulation and restructuring in both the gas and electric power supply chains in Canada and in the United States;
- energy convergence as a result of the increasing use of natural gas for electric power generation;
- increasing pressures on gas delivery infrastructure in western North America due to forecast increases in natural gas demand though the company is optimistic that infrastructure projects (such as Inland Pacific Connector or similar projects developed by other companies) will be initiated during the five-year forecast time-frame to help reduce this risk;
- increased gas price volatility albeit without the extreme swings as experienced in 2001;
- increasing volume of off-system sales transactions to optimize assets within the supply portfolio (GSMIP related issues);
- decreased customer confidence in the energy sector due to the Enron failure and regional crisis like the California situation in 2001 and increased focus on managing counter-party and credit risk;
- increasing use of price risk management instruments to manage price volatility and corresponding increased need to administer credit;
- increasing reliance on information technology to help manage and run the business;
- increasing business risk due to increased business complexity created by above-mentioned trends;
- increasing staff recruitment and retention costs due to higher industry demand for knowledgeable staff and increasing staff turnover rates; and
- increasing gas cost reporting requirements for regulatory and other initiatives.

Planned mitigation strategies and actions for the above pressures include:

- increased portfolio management and optimization activities;
- active investigation and support of various infrastructure expansion initiatives;
- process improvements and use of technology to offset and aid in managing the added complexities; and

- increased focus on business risk management, including operational and credit risks.

Costs for these strategies are reflected in the 2003 Forecast Gas Supply O&M.

ii) Forecast 2003 O&M for Gas Supply

The activities of Gas Supply are funded through both utility O&M and Core Market Administration which is recovered in core market gas supply costs. Activities such as planning, credit management, accounts payable, and compliance & audit checks are funded through Core Market Administration. Financial analysis and reporting are funded through both O&M and Core Market Administration. All aspects of optimize and schedule, which includes nominations, along with overall business risk management are funded through O&M. In addition, O&M funding is used to complete process review, IT management oversight and the activities of the forecasting and upstream strategy group.

The Forecasting group within Gas Supply develops customer energy use and customer additions forecasts, provides analysis and decision support on longer-term supply/demand and pricing issues, performs portfolio modelling and handles relationships with upstream pipelines and federal agencies (NEB, FERC).

The forecasts prepared by this group are used to plan and build an optimal gas supply portfolio, which ensures a reliable source of commodity services to customers. The forecasts also aid transmission and distribution operations in planning their O&M and capital programs, which are major contributors to the Company's overall cost of providing service.

Attention to upstream pipelines ensures that external pipelines and agencies consider the needs of BC Gas' customers. For example, the Forecasting group played the lead role in negotiating a new transport arrangement on the Duke system starting in the winter of 2003/04 that will replace the SCP related Station 2 to Huntingdon capacity with capacity from Kingsvale to Huntingdon. As a result of the negotiation the cost of the proposed Duke expansion will be reduced by some $70 million and the amount of firm service held by BC Gas will be reduced. These changes result in ongoing annual savings to customers of $5.5 million in firm service tolls.

The Company's Gas Scheduling and Nominations services provide a vital service to the regional marketplace. The ability of BC Gas to centrally co-ordinate the flow of gas into the various B.C. market regions on every Duke nomination cycle and adjoining systems, such as TCPL and Williams ensures reliable and cost-effective control of gas volumes for all gas customers in B.C. With these services, BC Gas provides its transport customers with reasonable daily balancing rules, in comparison to the requirements of other pipelines, resulting in significant customer savings and risk avoidance.

The array of risk management services include providing direction and hands-on support for managing legal and credit risks, ensuring compliance with price risk management policies and identifying and preparing business resumption plans to manage other business risks.

The forecast 2003 O&M costs for Gas Supply are $2.0 million. The majority of the O&M costs for this group is labour (internal and consultant). Gas Supply closely manages the trade-offs between Company hires and consultant use. Opportunities for efficiency through business process change and technology use are also a key focus for the future.

iii) Historical O&M Costs, 1997 - 2002

The table that follows sets out historical Gas Supply O&M expenditures.

Gas Supply's Annual O&M Expenditures ($ millions)

	1997 Actuals	1998 Actuals	1999 Actuals	2000 Actuals	2001 Actuals	2002 Projected
Total Nominal O&M	**1.0**	**1.4**	**1.4**	**1.4**	**1.5**	**1.8**
Total Real O&M	**1.1**	**1.5**	**1.5**	**1.4**	**1.5**	**1.8**

Note: Real totals in 2002 values.

O&M costs over the past five years have been driven by upward pressure on labour costs coupled with staff additions.

iv) Forecast O&M Expenditures, 2003 - 2007

Looking beyond 2003, BC Gas is forecasting the costs for Gas Supply activities to face upward pressure but remaining generally stable in real terms. The forecast O&M expenditures for Gas Supply from 2003 to 2007 are set out below.

Gas Supply's Annual O&M Expenditures ($ millions)

	2002 Projected	2003 Forecast	2004 Forecast	2005 Forecast	2006 Forecast	2007 Forecast
Total Nominal O&M	**1.8**	**2.0**	**2.0**	**2.1**	**2.1**	**2.2**
Total Real O&M	**1.8**	**1.9**	**1.9**	**2.0**	**2.0**	**2.0**

Note: Real totals in 2002 values.

Core Market Administration

Core Market Administration costs relate to core market procurement activities, which essentially encompass the gas supply management function. For rate making purposes, the actual cost of gas procured for the core market and these administration costs are added together and recovered as part of the gas cost flow-through process. These are submitted to the BCUC yearly for review as part of the Annual Contract Plan.

Core Market Administration costs are not part of the Company's O&M for this Application. They are presented in this filing to provide background and present a full picture of the role of GS&T within BC Gas. The tables below present the historic and forecast Core Market Administration costs.

GS&T Core Market Administration Annual O&M Expenditures ($ millions)

	1997 Actuals	1998 Actuals	1999 Actuals	2000 Actuals	2001 Actuals	2002 Projected
Total Nominal O&M	**1.1**	**1.3**	**1.5**	**1.5**	**1.6**	**1.7**
Total Real O&M	**1.2**	**1.4**	**1.6**	**1.6**	**1.6**	**1.7**

Note: Real totals in 2002 values.

Cost pressures for Gas Supply (O&M and Core Market Administration) are primarily a result of labour pressures. However, operating costs and headcount for Gas Supply are projected to be stable over the five-year time period as productivity improvements will be implemented to offset future pressures. In addition, synergies between BC Gas and Centra will be realized to the benefit of each customer base.

Centra provides the merchant gas supply role for its core customers similar to BC Gas. Centra is a smaller utility and has out-sourced some of the supply functions. The out-sourcing fees paid by Centra to Engage for gas procurement and risk management are $0.4 million per year. Centra has terminated the Gas Management Services Agreement with Engage effective November 2002.

BC Gas will assume the trading and risk management tasks associated with the Engage contract and Centra is projected to pay BC Gas $100,000 for this service. The $100,000 is based on a pro-rated allocation of BC Gas' costs of providing these services. BC Gas will perform these activities with no increases in headcount or O&M expenses. Therefore, BC Gas will realize an overall decrease in the net Core Market Administration costs due to the revenue received from Centra and Centra will be receiving these services at a rate lower than its current fee.

The table below demonstrates the results of the rapidly changing energy market on Gas Supply (core market administration and O&M). The increased number and complexity of transactions and rapidly rising gas purchase costs result in both increased workloads and higher risk exposure.

Gas Supply Activity Volumes

	1997 Actuals	1998 Actuals	1999 Actuals	2000 Actuals	2001 Actuals
Hedging Transactions	17	40	30	51	127
Off-System Transactions	2,279	2,920	3,513	4,622	4,459
Gas Purchase Costs ($ millions)	534	591	675	1,393	1,441

To handle the increased workload and to manage the risk exposure, a variety of roles have been added. The increase in historical costs (O&M and Core Market Admin) reflects the addition of compliance roles to more closely monitor and mitigate business risk (counter-party failure, credit) related to gas procurement and fixed cost mitigation activities; process improvement roles to optimize overall business performance; third party pipeline relationship management roles and commodity price risk management roles.

A key example of the value this group brings relates to the Enron crisis. Through diligent risk management and credit follow-up BC Gas suffered no revenue loss when Enron declared bankruptcy, while several other companies incurred high losses.

BC Gas has been effective in recovering fixed costs over the years while facing continually increasing numbers of transactions. This was recently confirmed by the 2000/01 GSMIP audit conducted by the Board.

While 2002 has not been as volatile, BC Gas expects that, moving into the future, Gas Supply will operate in an environment of increasing complexity and continuing price volatility. The ability to provide reliable gas supply management capabilities will require investments in people, process and technology. Gas Supply continues to optimize its performance by refining processes and roles so as to minimize cost increases. Long range planning for supply as well as for industry and technology trends is a key focus to ensuring continued customer service.

d. Transmission

Transmission Asset Management (Transmission) is responsible for the safe and reliable operation and maintenance of the Interior Transmission system mainline, Southern Crossing Pipeline, Coastal Transmission system, some transmission pressure lateral pipelines, mainline compressor stations, and the Liquefied Natural Gas (LNG) plant at Tilbury Island.

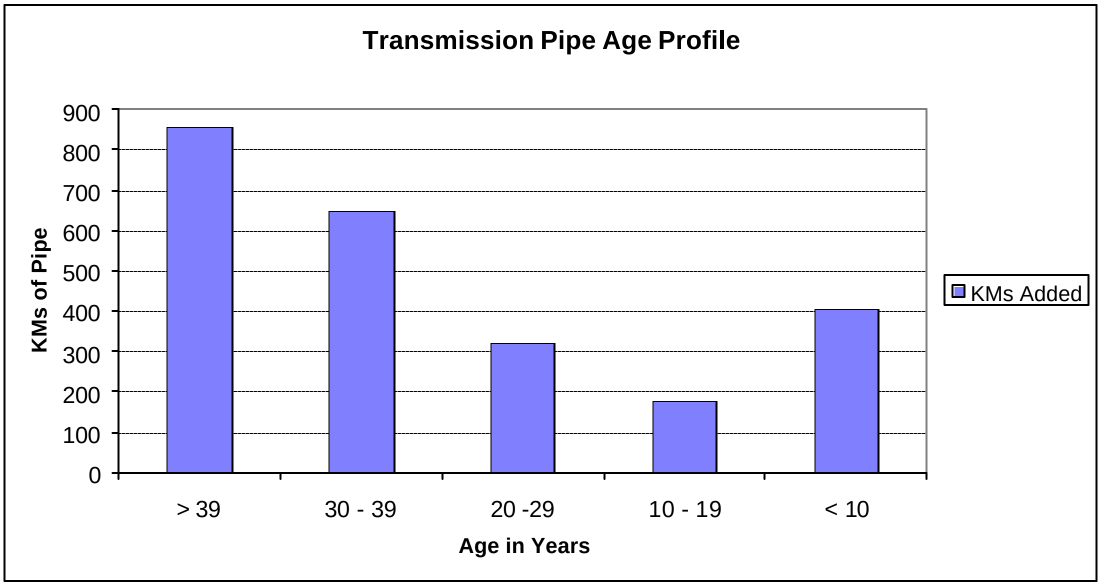
Transmission ensures the high-pressure pipeline system is available to deliver gas from interconnecting pipelines and storage facilities to gate stations operated by BC Gas Distribution, Centra Gas BC, and a number of industrial customers, safely, reliably and cost-effectively.

Transmission is comprised of three groups:

- Transmission Operations is responsible for managing the gas control centre including the SCADA system; managing the programs to ensure the safety and integrity of transmission facilities; managing the day-to-day operations of the transmission pipelines, rights of way, compressors and LNG plant; and providing technical support to the transmission group;
- Project Development is responsible for identifying and reviewing new transmission infrastructure requirements; and
- Project Assessment is responsible for project management of transmission infrastructure projects.

i) Transmission O&M Cost Drivers

Almost one-third of the total mainline transmission pipeline length is now over 40 years old and almost one half is over 30 years old. The level of expenditures required to operate and maintain the older segments to the required standard of safety and reliability has grown due to the need for selective pipe replacement or repair, as identified by regularly scheduled internal inspections and assessments of pipe condition.



Transmission has operated in an environment of increasingly more stringent legislative and regulatory requirements over the past five years. One result has been significant upward cost pressure in meeting codes, regulations and good operating practices. Examples can be found in areas as diverse as environmental, health and safety compliance, pipeline maintenance, record keeping, and transmission system integrity management.

Increased O&M spending in areas or initiatives such as the Transmission Operations System Review ("TOSR"), employee training, and environmental auditing activities have to date been accommodated through efficiency improvements, and deferral of other programs. The TOSR program alone required $1.0 million per year of funding for the past four years which was accommodated within approved funding levels through reductions in other areas.

Costs have been managed by reducing management development training and travel expenditures, deferred hiring, as well as fuel gas savings realized due to warmer than historical winters over several of the past years. Transmission is undertaking measures to prepare for increasing numbers of employee retirements over the next several years and as a result, deferral of recruitment and development of existing employees is no longer considered prudent.

Following September 11, Transmission has invested considerable resources in understanding, planning and taking action to improve the security of its installations. Costs are increasing throughout the BC Gas service territory with respect to managing stakeholder interests, relationships and access permitting. For example, a recent decision by the

Pentiction Indian Band to initiate a suspension of access to the BC Gas transmission pipeline where it passes through the Band's territory until further, unspecified discussions occur, is indicative of the growing challenges facing Transmission.

This lack of access will ultimately delay TOSR and Integrity Work planned for those areas as access to both right of way and the underground piping will be periodically required. No regularly scheduled line patrols, corrosion and leak surveys are possible until the situation is resolved. Within Transmission these additional steps to gain land access have reduced the efficiency of some operating groups, caused delays, and tied up scarce resources that could better be used elsewhere. Time and resources will be required to resolve these issues with the band.

ii) 2003 Forecast Transmission O&M

For 2003, Transmission forecasts on O&M requirement of $12.5 million. A review of these requirements is provided in the following discussion.

Changing environmental requirements and the subsequent O&M cost impacts are a reality. For example, methane emissions are now minimized wherever possible due to growing concerns about impacts of emissions on the ozone layer of the atmosphere. As a result additional time and resources (cost) are required to reduce emissions each time a pipeline is taken out of service for repair or alteration, a relatively common event in the operation and maintenance of the transmission system. A growing awareness of the environmental impact of greenhouse gas emissions has also resulted in the requirement for funds to be spent to evaluate the actual emissions of operating facilities and to undertake programs to upgrade facilities to reduce these emissions in line with national voluntary compliance commitments. An incremental amount of $0.3 million has been allocated in Transmission's 2003 O&M to handle environmental requirements. Pressure for environmental compliance changes will likely increase with ratification of the Kyoto Accord, which may force an acceleration of planned retrofits.

Addressing increased industry, regulatory and public awareness of the consequences of inadequate pipeline maintenance has been a major area of cost pressure for Transmission over the past five years. In 1998, the Transmission Operations System Review (TOSR) identified actual and potential deficiencies with regard to meeting codes, standards, industry practices and regulations and documented the increasing regulatory and public expectations concerning safe operation of the pipeline system. Initial estimates of funding were approximately $1.3 million per year for five years. This initiative allocated $1.0 million per year of incremental O&M funding to remedial activities such as correcting right of way deficiencies, developing and delivering programs for pipeline operator training and certification, and improving the quality and accessibility of mandatory system records.

Damage prevention of transmission pipelines through the management of rights of way has become a high priority in the past five years. Increasing levels of concern by all stakeholders regarding pipeline safety in light of numerous incidents that have attracted media coverage have accelerated BC Gas' efforts to bring rights of way up to a higher standard. Improvements in terms of signage and demarcation to help prevent third-party damage, removing right of way encroachments, and controlling vegetation to maintain visibility of right of way boundaries have been made. The increase in annual funding requirements to manage rights of way to a higher standard has in part been funded through TOSR.

When the TOSR program was developed in 1997/98, the project plan was designed to address the list of known deficiencies over the course of five years, with completion at the end of 2002. As the program has progressed, additional material deficiencies have been found that require correction, and funding. The Company's current projections of the levels of work required indicate that $0.8 to $1.0 million per year of expenditures in this area will be required through 2007. These funds are required for activities such as: ongoing right of way vegetation management, improved record keeping for physical plant and right of way information, increased right of way patrol frequencies due to increased urbanisation, and addressing an increased number of areas where thickness of cover over transmission lines has been found to be insufficient.

Cost pressures are also expected from a program currently underway to identify and upgrade a large number of locations where roads cross BC Gas transmission lines. A high volume of work will be required over the next five years to ensure that heavy truck traffic does not negatively impact transmission piping integrity. This need has arisen in many cases because of changed use by third parties, of what were formerly hunting trails or fire access roads, to logging and timber hauling activities. It is estimated that five to ten of these types of crossing upgrades will be required in 2002 at a cost of $250,000 to $400,000. Similar activity levels are forecast in 2003 and succeeding years

Increasing development in proximity to some areas of pipeline rights of way and near facilities such as the LNG plant and major compressor stations have increased the requirements for general right of way management activities such as landowner relations and damage prevention programs for underground facilities. Unintentional damage by third parties continues to be the leading risk to underground infrastructure.

Over the past five years, incidences of third party damage to BC Gas' pipeline system have increased. As a result, the Company has expanded its program to increase landowner awareness of pipeline location as well as highlighting the need for landowners and contractors to obtain pipeline information prior to beginning any subsurface work. These efforts have tripled the cost of the program from 1999 to 2002. The planned 2003 expenditure level for this program exceeds $125,000.

The Southern Crossing Pipeline went into service in late 2000. Its first winter of service was very mild with statistically low amounts of snowpack and spring runoff. It is anticipated that some localized erosion problems will be encountered over the next several years. These problems have the potential to increase Transmission's operating costs as they will be dealt with after the Southern Crossing Project costs are finalized in 2002. The environmental sensitivity of some areas traversed by the pipeline requires ongoing monitoring and immediate action should a problem arise in order to prevent non-compliances with the *Fisheries Act* and other regulations. The SCP also increased the total length of right of way with corresponding increases in monitoring costs. The planned 2003 expenditure level for right of way patrols is $65,000. The total funding for SCP and the FV compressor station in Transmission's 2003 O&M is $2.3 million.

Over the five-year forecast period, it is estimated that at least 15% of skilled front line employees within Transmission will retire. Action must be taken to address the situation. Allowances for increased levels of employee training and knowledge transfer to begin preparing for replacement of these skilled employees have been included starting in 2003. Funding requirements for 2003 have been projected at $0.2 million.

The Project Planning group assesses the need and plans for new infrastructure resources for the Company. By understanding both regional resource requirements and the requirements of the Company's customers, the group is able to assess the types of infrastructure enhancements required to meet customer needs. Infrastructure solutions may involve the Company building and owning assets or leasing or contracting for the use of other infrastructure.

The group co-ordinates the necessary project development elements for larger capacity related projects such as Okanagan Reinforcement, and Coastal Transmission Upgrades. The goals of this group are to ensure long-term efficient and reliable natural gas transmission pipeline and other infrastructure capacity for residents and businesses of British Columbia.

Transmission O&M costs have also been reduced by revenues to be recovered from Centra for services provided by Transmission. Centra provides the transmission management role for its core customers similar to BC Gas. However, because Centra is a much smaller utility than BC Gas, it is more efficient for Centra to out-source some of these functions. The out-sourcing fees paid by Centra to Westcoast (Duke) for Gas Control and SCADA services are $0.3 million per year.

BC Gas will assume these Centra activities effective September 2002. Centra is projected to pay BC Gas $0.2 million for this service.

BC Gas will perform these activities with no increases in headcount or O&M expenses, thus realising an overall decrease in net O&M costs while Centra will be receiving these services at a rate lower than its current fee.

iii) Historical O&M Expenditures, 1997 - 2002

The table that follows shows historical Transmission O&M costs. It depicts a trend of increasing O&M costs. Explanations are given following the table.

GS&T's Annual O&M Expenditures ($ millions)

	1997 Actuals	1998 Actuals	1999 Actuals	2000 Actuals	2001 Actuals	2002 Projected
Total Nominal O&M	**7.5**	**7.2**	**8.6**	**8.8**	**9.8**	**10.6**
Total Real O&M	**8.0**	**7.6**	**9.0**	**9.1**	**9.9**	**10.6**

Note: Real totals in 2002 values.

TOSR identified deficiencies with regard to meeting codes, standards, and regulations and the increasing expectations regarding system integrity. As discussed above this initiative identified $1.0 million per year of incremental requirements

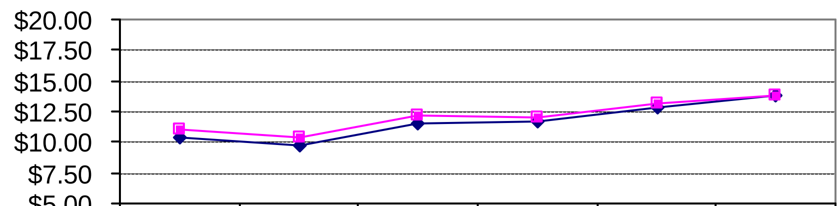
In 2000, the O&M budget was increased to accommodate the incremental operating expenses associated with SCP and the Langley Compressor Station. These costs included additional staff, fuel, right of way monitoring and other activities. The additional O&M costs impact of these two assets was $2.0 million in 2001. This cost increase was offset by productivity improvements that resulted in a savings of $1.0 million.

The projected O&M forecast for 2002 for Transmission reflects increases for fuel costs, replacement of annual funding for right of way maintenance, additional work on maintenance of operating records and operator competency training and certification.

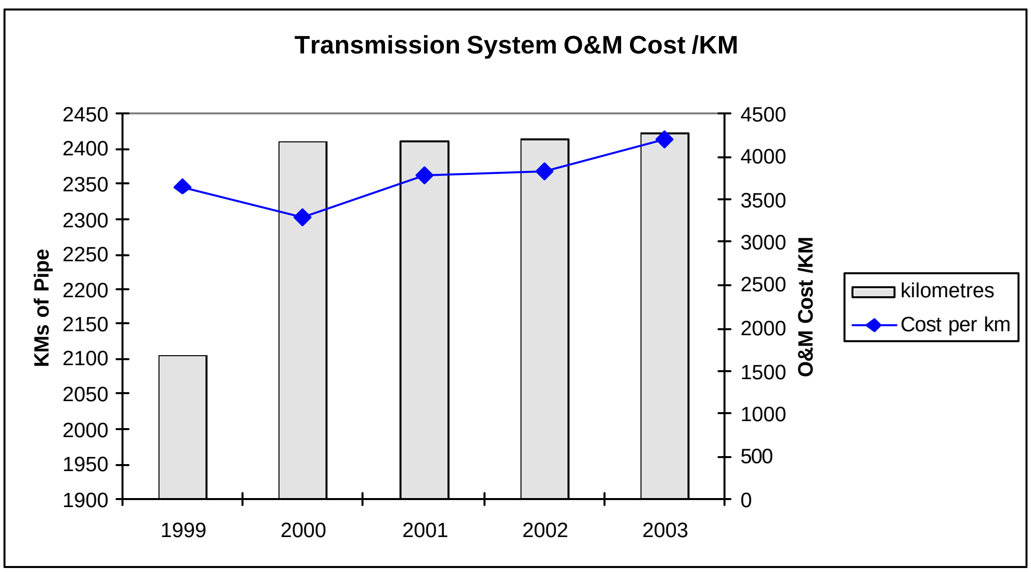
The chart below show Transmission costs per customer and per kilometre of transmission pipe. Costs are increasing at a higher rate than customer growth due to the higher costs associated with the ageing infrastructure.

Transmission's O&M Cost /Customer - Historical

(Real Cost in 2002 Value)



	1997	1998	1999	2000	2001	2002
Nominal Cost	$10.41	$9.81	$11.54	$11.65	$12.89	$13.80
Real Cost	$11.09	$10.42	$12.13	$12.02	$13.07	$13.80



iv) Forecast O&M Expenditures, 2003 - 2007

Looking beyond 2003, BC Gas is forecasting the costs for Transmission activities to face further upward pressure. Increases beyond inflation planned for the five-year forecast period are driven by projected cost increases related to own-use fuel (both price and quantity) and are approximately $50,000 per year. No additional headcount increases are planned for the five-year forecast period. The forecast O&M costs for Transmission 2003 to 2007 are set out below.

Transmission's Annual O&M Expenditures ($ millions)

	2002 Projected	2003 Forecast	2004 Forecast	2005 Forecast	2006 Forecast	2007 Forecast
Total Nominal O&M	**10.6**	**12.1**	**12.4**	**12.8**	**13.2**	**13.6**
Total Real O&M	**10.6**	**11.9**	**12.0**	**12.1**	**12.3**	**12.4**

Note: Real totals in 2002 values.

Transmission has a successful track record of providing customers with safe and reliable gas transmission service. Well-established programs to manage system integrity, pipeline location public awareness and damage prevention have contributed to a history of excellence in operating and maintaining the transmission pipeline system at the lowest reasonable life-cycle cost.

4. MARKETING & CUSTOMER CARE

The primary responsibilities of Marketing and Customer Care are to manage relations with all customer groups and to manage the Company's internal and external communications requirements. Marketing and Customer Care provides an organizational focus for BC Gas in the delivery of these services to residential, commercial, and industrial customers, as well as communications with employees and external stakeholders. A key component of customer relations is the provision of a complete suite of customer care services. The majority of these services are provided through an outsource agreement with CustomerWorks LP, including the provision of call handling, customer billing, payment processing, meter reading, and credit and collections services. Customer care services are provided at competitive prices and at service quality levels reflective of industry standards. A sample of customer care and support documents are found in the jacket under the Appendices Tab.

Other services provided by Marketing and Customer Care include customer education and communications, market research, energy efficiency and conservation (DSM) programs and trade relations. In order to help customers use gas efficiently and safely, customer education and awareness programs will continue to focus on demand side management, a greater understanding of gas rates and options, and customer safety. Additionally, new products and services will be developed and implemented in response to customer demand.

The Marketing and Customer Care business unit is organized into four departments. The largest in terms of annual O&M budget is Customer Care, whose primary function is the provision of customer care services through the management of the CustomerWorks contract. The other departments are Market Development (for residential and small commercial customers), Marketing Services (for industrial and large commercial customers), and Strategic Communications. These four departments are overseen by the Vice President (VP) of Marketing.

Marketing and Customer Care is staffed at a level of 71 FTEs. Of this total, four are in Customer Care, 16 in Market Development, 17 in Marketing Services, and 34 in Strategic Communications.

Through customer research, the Company has determined the most important customer satisfaction attributes as identified by customers. The organizational structure, with all customer relations and communication departments reporting to the VP of Marketing, is designed to support the Company's focus on these attributes. The Marketing and Customer

Care business unit will continue to focus on developing a full understanding of changing customer needs and expectations and developing product and service solutions that meet those requirements. In addition, Marketing and Customer Care will ensure consistency in messaging across the broad range of audiences including customers, employees and various external stakeholders.

a. Cost Drivers

The total number of customers is the key cost driver affecting Marketing's O&M expenditures. This affects the provision of customer care services, including meter reading, billing, call answering, payment processing, and credit and collections activities. Other drivers that will influence service costs in the foreseeable future include the frequency of changes in natural gas and alternative energy prices, the introduction of customer choice and new gas safety legislation.

In response to changing gas prices, energy management has become a key customer concern and consequently a focus of the Company's communication plans. Efforts will continue in this area, reflecting customers' needs for BC Gas' assistance in managing their costs. BC Gas customers have also expressed a strong desire for product choice, again in response to higher gas prices. BC Gas is investigating options to provide customers with increased choice through additional supply options.

There is also a continuing need for safety messages and reminders, in keeping with the duty of care associated with products like natural gas and its use in customers' homes and businesses.

b. Forecast 2003 O&M Expenditures for Marketing and Customer Care

The forecast 2003 operating and maintenance expense for Marketing and Customer Care is $57.9 million. This requirement is set out in the following table.

O&M Forecast - Marketing & Customer Care ($ millions)

Resource Group	2003
Contracts	42.4
Bad Debt & Supplies	10.5
Labour	5.0
Total	**57.9**

The largest component is comprised of contracts, of which the outsource agreement with CustomerWorks represents $42.4 million, or 73% of total O&M. The next largest component is comprised of service, materials, and supplies totalling $10.5 million, or 18% of total O&M. Of this amount, bad debt represents $5.1 million. The remaining $5.0 million of the total 2003 requirement is required for the compensation costs incurred by the business unit's staffing level. This represents 9% of total 2003 O&M. A summary of this O&M expense forecast for 2003, by functional area, is set out below.

Customer Care

The Customer Care forecast O&M requirement of $47.8 million for 2003 is comprised of three major cost components. Labour costs for the department's 4 FTEs are forecast to be $0.2 million, including benefit costs. The contract with CustomerWorks accounts for $42.0 million. An additional $0.4 million is required for expected changes to the services provided under the terms of the contract. Bad debt expense is forecast to be $5.1 million. The remaining $0.1 million is required for office supplies and employee expenses. This forecast level of O&M expenditure is required by Customer Care in order to meet their customer care and bad debt management responsibilities.

Customer Care is responsible for the management of the contract with CustomerWorks, and also manages credit and collection activities for residential and small commercial customers. In managing the contract with CustomerWorks, the Customer Care department monitors service levels, ensuring that contracted service levels are met. Through the agreement, the opportunity exists to revise service levels periodically in response to changes in technology as well as customer expectations. The Customer Care department also provides business process direction, as well as financial and fiscal management of all Customer Care activities, including bad debt exposure. The bad debt component of credit and collections, overall credit and collection policy responsibility, and business process direction is retained by

BC Gas. Ensuring customer expectations and requirements are met, as well as the need to manage costs, remain the goals and objectives Customer Care.

Marketing and Customer Care is also responsible for a company wide process redesign initiative entitled “Meter to Cash”. The “meter to cash” process includes managing all activities from the time that a meter is read to production and mailing of a customer’s bill, to processing payments made by customers. A critical component of this process is the management of credit and collections activities. BC Gas expects this process redesign to be completed by the end of 2002.

Potential changes to the service levels provided by CustomerWorks are reflected in the forecast. Scope changes generally involve changes to existing services provided by CustomerWorks. The scope of services documented in the schedules to the Client Services Agreement reflect all customer care services BC Gas provided to Interior customers as at December 31, 2001 as well as any new services that could be reasonably anticipated at the time the contracts were negotiated. However, through the term of the contract, BC Gas expects some services to change, and new services to be added, in response to changing customer expectations, regulatory requirements and opportunities that could not have been foreseen at the time the contract was negotiated. Scope changes may proposed by either BC Gas or CustomerWorks and will be reviewed and negotiated. In accordance with the Commission’s Order, any significant improvement initiatives or scope changes relating to this agreement will be presented to the BCUC for review.

BC Gas has experienced a significant increase in bad debt expense over recent years, primarily driven by the higher cost of the gas commodity. This increase has also caused BC Gas to incur higher costs in credit and collection activities. While BC Gas is projecting a reduction in total revenues for 2002 relative to 2001 based on anticipated gas cost reductions, bad debt expense is expected to increase in 2002 as a result of moving away from joint billing with B.C. Hydro.

The current B.C. Hydro Services and Revenue Agreements allow BC Gas to benefit, through the factoring of receivables, from the lower bad debt levels experienced by the electric utility. The larger customer base and debt load associated with joint gas and electric collections processing enables B.C. Hydro to implement and support specialization and efficiencies that are not available to BC Gas processing collections for gas only accounts. Another consideration is the essential nature of electricity to customers, relative to natural gas, when disconnected for non-payment. Customers are more likely to reconnect their electricity quickly than their natural gas service. Consequently, BC Gas' bad debt experience rate is currently lower in the Lower Mainland under the B.C. Hydro agreement than in the Interior.

The bad debt experience rate for 2002 for the Lower Mainland customers is projected to increase from 0.29% to 0.47%. The bad debt experience rate for Interior customers has traditionally exceeded 0.65%, reaching a high of 1.0% in 2001. BC Gas is improving its business processes as well as initiating changes in CustomerWorks' processes, and believes a return to the historical benchmark of 0.65% is achievable. The higher experience rate associated with the migration of Lower Mainland customers to the new billing system causes a forecast increase in O&M requirements of approximately $1.1 million in 2002. However, process improvements after 2002 are forecast to deliver savings of $0.9 million in 2003 from the level in 2002. This saving is included in the O&M forecast for 2003.

Market Development

Market Development forecasts an O&M requirement of $4.1 million for 2003. This amount is comprised of $1.2 million for compensation expenses for 16 FTEs. A variety of contracts, including DSM, require $1.9 million. The remaining $1.0 million is required for a range of printing and advertizing expenses, as well as for own used office supplies and for employee expenses. This level of O&M expenditure is required by Market Development in order to meet their residential and small commercial customer management responsibilities.

The Market Development department focuses on residential and small commercial customers in the planning and delivery of customer education and communication, product development, and market research. The department also undertakes program development (particularly regarding energy conservation), carries out trade relations activities, manages customer connection policies, and produces marketing communications. Customer contact, in particular dealing with escalated calls from the call centres is also provided by Market Development.

Market Development creates messaging for customer education and communication on the topics of rate changes, natural gas prices, competition with alternative fuels, billing issues (e.g., launch of the new billing system), customer connection policies and regulatory changes (e.g., gas cost increases, rate design changes). Customers benefit by receiving the information they require and by gaining a better understanding of the services provided by

BC Gas and the use of natural gas as an energy source in their homes and businesses. This leads to greater customer satisfaction, fewer inquiries through the Company's call centres, shorter call times and fewer escalated calls, which helps to control costs. Market Development achieves this communication objective through the use of advertising, bill inserts, scripting for call centre representatives and handling of escalated customer calls. The task of this group has become much more challenging in light of the impact of frequent commodity price changes in the past two years.

In response to this heightened interest in energy prices, Market Development is actively investigating alternative product offerings such as fixed term pricing for the commodity portion of residential service. If viable, offerings may be made as early as 2003.

Market research activities focus on customer research (e.g., end-use studies), customer satisfaction, safety, and attitudes and opinions around Company initiatives. The objective of market research is to provide the information that is essential to support the development of programs and delivery of services to meet customer needs efficiently and cost-effectively. Over the next five years, this customer input will enable the Company to appropriately adapt to changes in customer requirements.

The primary focus of program development is on energy efficiency, often referred to as Demand Side Management, or DSM. Some programs, such as Gaslight Gourmet and Homeswest magazine, are also effective in presenting important safety information to customers. Heating equipment dealers and contractors often interact with BC Gas customers and potential customers at the time that fuel choices are made. The BC Gas trade relations department works closely with the trade to ensure that dealers and contractors are fully informed about the advantages of natural gas as an energy source. Trade relations is an effective tool in promoting primary demand for natural gas (particularly in the conversion market), as well as ensuring the on-going use of natural gas as customers upgrade to newer equipment and additional end uses. Energy efficiency messages are also effectively delivered through the trade.

The acquisition of new customers is significantly influenced by the connection policies of the Company. Market Development oversees both the Main Extension test, and the Company's service line connection policies. In compliance with the BC Gas Tariff, these policies are designed to balance accessibility to natural gas with appropriate cost recovery mechanisms.

Market Development also produces booklets and information sheets to help customers in their dealings with BC Gas and their use of natural gas. Topics range from a general introduction to BC Gas, to specific topics such as energy cost comparisons, and how to read your meter. These publications are available in hard copy, and are also available electronically on www.bcgas.com.

BC Gas continues to support initiatives to promote increased energy efficiency. Programs will be designed to increase the level of customer demand reduction opportunities for all vendors in energy efficiency markets and promote the capture of valuable peak day resource savings to reduce costs for BC Gas and its customers. Program activities may include:

- actively promoting legislative changes that result in increased energy efficiency;
- being involved in efforts to transform the operation of existing energy efficiency markets to higher, sustained levels of energy efficiency activity; and
- designing and implementing programs and activities to reduce peak day costs that can result in substantial benefits to BC Gas, its customers, and society.

Specific programs at BC Gas have targeted all customer segments including residential, commercial and industrial. DSM initiatives planned or under consideration for 2003 are:

- Hot Tips Promotion. This ongoing initiative is designed to improve the adoption rate of a variety of measures by residential customers. Hot Tips booklets are distributed through contractors, home centres and by mail;
- Furnace Tune-Up Promotion (Summer). This utility-sponsored $25 incentive is directed toward home furnace maintenance as a way of improving energy efficiency. In 2001, 27,324 customers took advantage of this program;
- Weatherization Promotion. This utility-sponsored incentive encourages customers to make envelope improvements to their home prior to the heating season. (under evaluation);
- High Efficiency Heating System Upgrade Promotion (Fall). This utility and trade-sponsored incentive ($150/$150 - $1000) encourages residential customers to upgrade

to a high efficiency (condensing) replacement furnace or boiler. In 2001, 1,423 customers took advantage of this program;

- Efficient Boiler Rebate Program. This incentive program encourages customers to install high efficiency boilers. (under evaluation);
- Commercial Utilization Advisory Program. This program provides customer site investigations, showcases examples of measures taken by commercial customers, and publishes benchmark energy utilization information. The site investigation includes a facilities walk-through, a consumption analysis and a written report to the customer indicating measures or equipment solutions that might be considered;
- Municipal 'Energy Matters' Workshops. Five workshops were held in partnership with municipalities and the Government of Canada during Winter 2001/2002 to encourage community energy planning and the adoption of "Green Building" techniques. A new municipal program is anticipated for 2003.

BC Gas proposes to spend $1.5 million per year in incentive grants for DSM programs, including the programs listed above. BC Gas requests approval for the continuation of a DSM deferral account for these incentive grants

<u>Marketing Services</u>

Marketing Services forecasts O&M expenses totalling $2.0 million for 2003. Of this total, $1.3 million is required for compensation expenses for the staff of 17. The remaining $0.7 million is required for a variety of printing and advertizing expenses, as well as for own use office supplies and employee expenses. This level of O&M expenditure is required by Marketing Services in order to meet their industrial and large commercial customer management responsibilities.

The Industrial and Large Commercial Marketing Services department is responsible for managing the transportation and marketing services function. This function includes such activities as energy services assistance, primarily in the form of Tariff change, education, and implementation of new and revised Tariffs as well as new products/services development for large commercial and industrial transport customers. Energy services assistance includes facilitating the relationship between the customer and BC Gas' operating departments, identifying and resolving measurement and billing issues, proactively ensuring customers are on the most advantageous rate schedule, educating customers about commodity choices, assisting with end-use installations, and providing Demand Side Management assistance. Marketing Services is also responsible for providing daily measurement data to marketers to support their information needs in managing their customers' expectations. Additionally, bypass agreements are administered, services for new customers are negotiated and issues such as infrastructure for existing customers are managed. New products/services development includes evaluating existing offerings to determine if they represent the right mix of customer service and core market cost recovery and the design, negotiation and submission of new and amended services to the British Columbia Utilities Commission. An example of this is the annual Rate Schedule 10 and 14 filing. BC Gas also provides the management of a supply portfolio for a number of commercial and industrial customers who have chosen BC Gas as their commodity supplier.

Industrial and large commercial representatives augment the collection efforts of CustomerWorks. Once an account is over 30 days in arrears the Commercial and Industrial representatives become involved and leverage any relationships that may exist. Typically, a decision to lock-off an account or come up with a payment plan will involve input from a commercial or industrial representative. Based on current workloads, one representative's time is spent on these activities. CustomerWorks will often be the first point of contact if a customer has no history with BC Gas account representatives. The protocol is for CustomerWorks to direct commercial or industrial inquiries to the appropriate representative. CustomerWorks also acts as the conduit for new service requests for commercial and industrial customers who do not currently have a relationship with BC Gas representatives.

The Industrial and Large Commercial Marketing Service department is currently working on system improvements to the transportation service scheduling systems that will support web-based nominations and ordering along with automated balancing calculations and reporting. Part of this process will also allow market participants to place intra-day orders. Along with these improvements BC Gas has also, over the past few years, undertaken a number of initiatives to improve the timeliness and accuracy of measurement data that is provided to Transportation Customers and Shipper Agents for balancing purposes. Major improvements have been achieved recently in this area. BC Gas intends to continue to improve this service so that customers will have greater accuracy and timeliness.

In the past, BC Gas was the exclusive supplier of gas commodity within the gas service area. Today, commercial and industrial customers are provided the option to source their own supply of gas commodity. In the future, residential and small commercial customers may also be offered commodity supply options. In preparation for full commodity unbundling, and to harmonize BC Gas' management of "the gas day" with the processes used by the interconnecting pipelines, the Company is in the process of realigning and enhancing its scheduling processes and systems. These changes include:

- Establishing Transportation Services within BC Gas as a separate entity from Gas Supply. This change has been completed. All shippers on the pipeline, including BC Gas, are required to nominate daily gas requirements on the LDC pipeline to Transportation Services.
- Providing web-based nominations. BC Gas is investigating the costs and processes to facilitate and require that nominations be carried out through the Internet. The process will include confirming response to requests, and on-line access to confirmed scheduled quantities. Web-based nominations are also considered a necessary pre-requisite to support the implementation of commodity unbundling for residential and small commercial customers.
- Offering more nomination cycles. BC Gas intends to offer full access to all four nominations cycles. Presently, access to only the Timely cycle is imbedded into the Tariff, while access to the other cycles are on a reasonable efforts basis.
- Automating inventory management. BC Gas is evaluating automating the process of managing Marketer inventory and providing on-line access to the data.

BC Gas is not proposing changes to the Tariff to reflect changes in business process associated with these scheduling changes at this time. Once the scheduling system enhancements are fully implemented, BC Gas will review the Tariff to determine the appropriate Tariff language changes necessary to support the enhanced scheduling service.

BC Gas is also working on new processes related to the billing of industrial and large commercial customers as well as third party gas suppliers. The processes in place currently rely on manual processes, in support of a small stand alone database/spreadsheet application. Effective November 1, 2002 the Energy Customer Information System provided by CustomerWorks as part of the customer care outsourcing agreement will be utilized to bill these customers. The process improvements associated with this are described in detail in the Tariff Change tab.

Strategic Communications

The Strategic Communications department forecasts an O&M requirement of $4.0 million for 2003. The largest component of this total is labour at $2.3 million that is required for the staffing level of 34 FTEs. Contracts, services, materials and supplies totalling $1.6 million are required for the purchase of a large part of the Company's office supplies, as well as costs for external consulting expertise, desktop publishing and advertising expenses, and employee expenses. This level of O&M expenditure is required by Strategic Communications in order to meet its communications and business unit management responsibilities.

Strategic Communications is responsible for providing internal and external communications services for the Company, including employee communications and media relations. This responsibility is met by ensuring that messages are consistent, timely, and delivered efficiently to customers, employees, stakeholders, and to the media. Increasingly, customers, stakeholders, and the media use the Company's web site as a source for accurate and current information. Strategic Communications also provides reception, switchboard, internal mail, and office supplies services.

Strategic Communications manages and safeguards the Company's image by ensuring the communication requirements of different departments are strategically aligned, of consistently high quality and are produced on time and within budget. The integration of Strategic Communications with the Marketing and Customer Care business unit ensures the alignment of key communication and messaging between customers, employees, media, and other stakeholders. Strategic Communications provides communication expertise and advice to departments throughout the Company to produce communication materials dealing with topics such as gas safety, energy efficiency, and gas pricing.

Strategic Communications also maintains an Emergency Communication Plan to co-ordinate all communication to BC Gas customers, employees, media, government, communities and special interest groups in the event of an emergency.

c. Historical O&M Expenditures, 1997 - 2002

A summary of Marketing and Customer Care's O&M expenditures from 1997 to 2002 is set out in the following table.

Customer Care & Marketing's Annual O&M Expenditures ($ millions)

	1997 Actuals	1998 Actuals	1999 Actuals	2000 Actuals	2001 Actuals	2002 Projected
Marketing & Strategic Comm.	7.8	7.4	9.6	11.1	9.8	10.1
Customer Care	24.1	27.7	20.2	22.6	26.5	42.1
Total Nominal O&M	**31.9**	**35.1**	**29.8**	**33.7**	**36.4**	**52.2**
Total Real O&M	**34.0**	**37.3**	**31.4**	**34.7**	**36.9**	**52.2**

Note: Real totals in 2002 values.

Total O&M costs incurred by the Marketing and Strategic Communications departments increased significantly between 1997 and 2002 for several reasons, most of which are attributable to the customer care function. Prior to 1998, the customer care function in BC Gas was managed on a decentralized basis using branch offices. In 1998 this function was centralized and the Kelowna call centre established. This centralisation identified efficiency savings that were realized in 1999. Unanticipated at the time was the increase in commodity prices that caused an increase in call volumes. This increase in calls required additional funding by the Kelowna call centre in both 2000 and 2001.

O&M spending by Customer Care increased by $18.0 million between 1997 and 2002. Of this total, approximately $2.4 million, incurred between 1997 and 2001, is attributable to customer care costs incurred to improve service levels in the Kelowna call centre in response to the spike in commodity prices, as well as a significant increase in bad debt costs. The remaining $15.6 million increase in costs, incurred between 2001 to 2002, is the result of the migration of Lower Mainland customers from the B.C. Hydro CIS to CustomerWorks Energy CIS, the move to monthly billing that migration enables, and the conversion of capital related costs to O&M expense associated with the transfer of customer care assets from BC Gas to CustomerWorks. Of this increase, approximately $1.0 million is attributable to the move to monthly billing. This cost will not impact customers' rates because of an anticipated reduction in rate base (working capital) arising from the cash flow impacts related to more frequent and timely billing. Approximately $3.8 million of the 2002 projected costs are attributable to the conversion of capital related costs into an O&M expense as a result of the sale of customer care assets to CustomerWorks. These costs have no impact on customer's rates because the Company's assets in rate base have been reduced. Approximately $4.6 million is attributable to a combination of Shared Services costs and transfers from other departments that play a role in the customer care function.

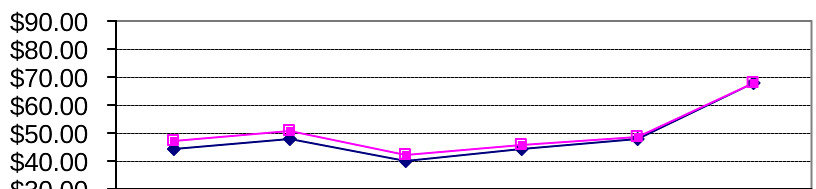
These costs also have no impact on customers' rates given that they are transfers of existing funding from other departments. Approximately $1.8 million is attributable to increased call handling costs, $0.2 million to increased credit and collections costs, $0.8 million to one-time migration transitioning costs, $1.3 million for a variety of support and field activity costs, and $0.5 million for migration communications costs. All of these costs were approved in the CustomerWorks Application and form part of the $54.54 cost per customer.

Finally, $1.1 million (out of a total bad debt of $5.9 million) is required for additional bad debt related costs attributable to residential customers in 2002 that arise as a result of the lost synergies related to the ability to action joint electric and gas debt. Approximately $0.4 million is attributable to external consulting required to help prepare the Company and CustomerWorks' hand-offs for migration, as well as for support costs incurred by the CustomerWorks contract management area.

The outsource agreement with CustomerWorks is a significant achievement during this period given that the primary driver of O&M costs during this period was increased and changing customer care requirements. The agreement with CustomerWorks places a constraint on cost pressures after 2003 that should hold future cost increases to well below the forecast rate of inflation. This constraint provides greater rate certainty to customers, something that market research indicates customers strongly desire.

A review of O&M costs per customer provides another view on historical resources demands. The table below shows that the O&M cost per customer in real dollar terms has increased significantly from $46.63 in 1997 to $67.69 in 2002. The cost per customer is expected to peak in 2002 and 2003 and decline after this during the forecast period.

Marketing & Customer Care O&M Cost /Customer - Historical
(Real Cost in 2002 Value)



	1997	1998	1999	2000	2001	2002
Nominal Cost	$44.31	$47.82	$40.05	$44.59	$47.84	$68.04
Real Cost	$47.21	$50.80	$42.08	$45.98	$48.51	$68.04

d. Forecast O&M Expenditures, 2003 - 2007

Marketing and Customer Care's O&M expenditures over the next five years are set out in the table below.

Marketing and Customer Care's Annual O&M Expenditures ($ millions)

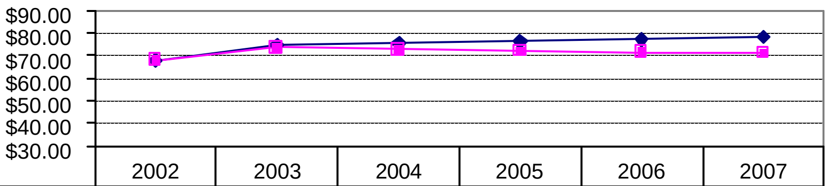
	2002 Projected	2003 Forecast	2004 Forecast	2005 Forecast	2006 Forecast	2007 Forecast
Marketing & Strategic Comm.	10.1	10.1	10.4	10.6	10.9	11.2
Customer Care	42.1	47.8	48.7	49.8	50.7	52.2
Total Nominal O&M	**52.2**	**57.9**	**59.0**	**60.5**	**61.7**	**63.4**
Total Real O&M	**52.2**	**56.9**	**57.0**	**57.3**	**57.3**	**57.7**

Note: Real totals in 2002 values.

Expenditures are expected to increase by $5.7 million in 2003 over the level projected in 2002, the reasons for which were reviewed earlier. After 2003 annual expenditures are forecast to increase moderately in real dollar terms. This change represents a considerable slowing of cost increases compared with the previous five years. The primary reason for this slowing of cost increases is that approximately $42.0 million of total O&M in 2003, and beyond, is tied to the outsourcing agreement with CustomerWorks which establishes a constraint on the cost per customer over the term of the agreement.

Expenditures for Customer Care after 2003 forecast some non-inflationary increases. These increases relate primarily to the impact of customer additions on the contract with CustomerWorks, and the cost of possible change controls to the outsource agreement with CustomerWorks. Approximately $0.5 million are included in the forecast for each item in each year beginning in 2003. In 2005, $0.3 million is included for costs to help prepare a request for proposal for the anticipated renewal of the customer care outsource agreement at the end of 2006. 2007 includes approximately $0.5 million for a possible increase in the renewal cost of the customer care outsource agreement.

The effect of the outsourcing agreement on future cost trends is also seen when reviewing O&M costs per customer as reflected in the following table.



	2002	2003	2004	2005	2006	2007
Nominal Cost	$68.04	$74.69	$75.29	$76.29	$76.98	$78.25
Real Cost	$68.04	$73.44	$72.72	$72.24	$71.47	$71.22

The forecast real O&M cost per customer shows a decline between 2003 and 2007. This decline is forecast to be 3.0%. As discussed earlier, the decline in the real cost per customer is largely attributable to the outsourcing arrangement for customer care services.

Marketing and Customer Care focuses on the most important customer satisfaction attributes as identified by customers. As a result, Marketing and Customer Care is able to develop an integrated knowledge of customer needs and expectations, and will develop solutions, such as customer choice, that meet customer expectations cost-effectively. A key achievement in this respect was the negotiation for the provision of customer care services by CustomerWorks. The agreement provides customers with rate certainty through a fixed price per customer over the five-year terms, as well as a real declining cost per customer over the period of the term.

Frequent changes in natural gas prices have focused customer communication activities. The frequency of rate changes was accommodated within existing budgets by reducing the volume of outbound communication such as advertising and billing inserts. However, the volume of incoming inquiries, some of which are handled within Market Development, required the shifting of resources from other activities.

Frequent changes in retail natural gas prices, as well as changing customer and stakeholder expectations needs will largely shape BC Gas' future communication. Previous rate changes announcements have focused on explaining the details of why rates are changing. BC Gas will continue to educate and explain to customers why their rates are changing more frequently and why natural gas prices have become more volatile. The Company will also continue to explain what BC Gas is doing to manage natural gas rates and show how both gas supply and distribution costs have been managed.

e. Process / Tariff changes

The Marketing and Customer Care Department is engaged in a number of business process reviews driven by the need to maintain the quality of service provided to customers. The department, through its routine interactions with customers, receives feedback regarding the services provided for in the Tariff. An example of this is the transportation customers' request for a fixed rate commodity offering that was addressed with the development of the current Rate Schedule 14 Tariff offering. In addition, the department performs customer research that may result in the identification of potential new service offerings or changes to aspects of the General Terms and Conditions. As a result of these process initiatives and customer feedback, several changes have been identified that require revisions to the Tariff. The specific Tariff change requests are discussed in detail in Section F of the Application.

5. REGULATORY, ENVIRONMENT, HEALTH & SAFETY, SUPPLY CHAIN & LOGISTICS, AND LEGAL & RISK MANAGEMENT (“RESSCLL”)

The Regulatory; Environment, Health and Safety; Supply Chain and Logistics; and Legal and Risk Management departments (collectively called “RESSCLL”) provide support services to other business units of the Company. RESSCLL is made up of six departments with the following responsibilities:

- Regulatory is responsible for the provision of regulatory services, including preparing major revenue requirement and rate design applications, applications for Certificates of Public Convenience and Necessity (“CPCN”), preparing tariff changes, and providing interpretation, education and communication of tariffs and regulatory policies to various departments throughout the Company. Many of the activities performed within Regulatory are the result of statutory requirements but the department is also responsible for co-ordinating timely responses and ongoing communications to the Commission, stakeholders and customers on a variety of issues.

- Environment, Health and Safety is responsible for the management systems controlling environmental affairs, employee occupational health and safety programs, public and customer safety, emergency preparedness and response, and security. A sample of various safety and emergency preparedness materials can be found in the jacket under Tab I. These programs assist BC Gas in ensuring environmental compliance and a safe environment for customers, public and employees. BC Gas' employee safety programs ensure that the workforce meets Workers Compensation Board legislation requirements thereby reducing the costs associated with workplace injuries and lost time incidents. The department also oversees environmental activities and programs that uphold customer and public expectations regarding environmental due diligence and habitat preservation.

- Supply Chain and Logistics is comprised of the purchasing, materials quality, welding, prefabrication and machine shops, stores and trucking, and accounts payable functions. These areas are responsible for ensuring that materials and services are effectively and efficiently procured, manufactured, tested for fitness of use, paid for and distributed to BC Gas’ operating and support groups. This group procures between $60 million and $200 million of materials and services annually. It also fabricates critical system components that are installed in the distribution system and is also responsible for responding to large diameter steel pipe emergencies for the Company's system. The accounts payable group is responsible for ensuring vendors are paid accurately and in a timely manner.

- Facilities is responsible for acquiring and maintaining facilities throughout the Lower Mainland and the Interior service areas. Facilities ensures that the Company and its employees have a suitable work environment with safe and efficient buildings and workspaces. This department also processes, services, and manages the Company's requirements for office furniture and equipment, telecommunications, workspace changes and moves, and building security.

- Land Services is comprised of land services and property tax management components. The land services component is responsible for securing adequate property rights and approvals to meet BC Gas' transmission and distribution real property requirements. The property tax management section monitors that property taxes are properly assessed to minimize their cost.

- Legal and Risk Management includes the legal services, and the risk management and insurance services areas. Legal is responsible for the delivery of legal services to the Company which are provided through a combination of internal and external resources. Approximately 60% of all of the legal services required by the Company are provided by internal counsel. The balance of legal services required by the Company is sourced from a number of external law firms. Risk management and insurance services is responsible for placing and managing the Company's insurance requirements, construction bonding, and claims management, as well as ensuring that the organization has effective risk management processes in place.

a. Cost Drivers

Over the last several years there has been a general hardening within the insurance market which, combined with the impacts of the September 11th attacks, has created a substantial cost pressure on insurance rates.

The O&M costs incurred by the Regulatory, the Environment, Health and Safety, and the Legal and Risk Management departments are driven primarily by external legislative and regulatory requirements. Statutes such as the *Utilities Commission Act; Oil and Gas Commission Act; Workers Compensation Act*; *Environmental Assessment Act*; Fire Codes and Safety Standards, and other practices dictate the level of service, and the reporting and compliance activities, that each of these groups must perform. Furthermore, these departments are responsible for monitoring and assessing the impact of changes to their respective acts and standards, and the development, communication and implementation of programs necessary to address any change.

Other factors also affect the level of O&M expenditures required by RESSCLL departments. The Land Services department, for example, is affected by land access and use issues which exist in both the Lower Mainland, where increased urban density is making it more difficult to expand distribution infrastructure, and in the Interior, where aboriginal interests require greater understanding and diligence. These external factors increase the staff time required to resolve issues and also the cost of acquiring property rights. The Facilities department's ability to reduce the costs associated with the Company's leased offices, including its ability to sublet the existing excess capacity at the 1111 West Georgia Street location, is directly affected by the commercial rental market within the Lower Mainland.

b. 2003 Forecast O&M Expenditures for RESSCLL

RESSCLL forecasts an O&M requirement of $21.3 million for 2003. The following table sets out this requirement by department.

RESSCLL's Forecast O&M ($ millions)

Department	2003
Regulatory	3.7
Environment, Health, & Safety	2.0
Supply Chain & Logistics	4.1
Facilities	6.0
Lands Services	0.6
Legal & Risk Management	4.9
Total O&M	**21.3**

The 2003 forecast expenditure for each of the departments, with the exception of the Legal and Risk Management area, remain relatively stable compared with the 2002 levels. The primary cost pressures for 2003 relate to the increased insurance premiums and inflation. These pressures will be reviewed in further detail in this section.

The Regulatory department's O&M forecast for 2003 is $3.7 million. The majority of this amount is required for resources needed to perform activities such as compliance reporting, analysis, and filings and applications. The 2003 O&M cost associated with the RESSCLL Vice-President's area is also incorporated in this total. Labour expenditures represent $2.0 million of the Regulatory department O&M. The non-labour components relate mainly to the BCUC Assessment fees of $1.4 million, and $0.3 million in expenses such as consulting, office supplies, stationary, and travel. The complexity of the environment in which BC Gas operates is considerable and therefore the department requires sufficient resources to ensure the department can effectively respond to the requirements of customers, the Commission and other stakeholders.

The Environment, Health and Safety department's forecast $2.0 million in expenditures are required for activities related to ensuring BC Gas complies with environmental standards; maintains emergency preparedness; provides a safe environment for customers, public and employees; and administers system security. Approximately $1.2 million is labour expenses. The remaining $0.8 million is comprised of non-labour components for expenditures ranging from safety communications to the maintenance of material safety data sheets and performing industrial hygiene monitoring at work sites. The need for a properly developed and implemented environmental and safety management system is critical to reflect BC Gas' commitment to conduct its business in a safe and environmentally responsible manner.

The Supply Chain and Logistics department's forecast $4.1 million in expenditures is required to complete purchasing, materials quality, welding, prefabrication and machine shops, stores and trucking, and accounts payable activities. This department ensures that materials are purchased, manufactured, quality tested, and distributed efficiently for use throughout BC Gas' service area. The accounts payable group ensures the accuracy and timeliness of payments. In 2002, the accounts payable group was centralized in RESSCLL and streamlined, eliminating 4.5 FTEs in other areas of the Company. This department's O&M requirements are comprised primarily of $3.5 million in labour expenses for its staff. The remaining $0.6 million is for a variety of materials and services including training, tools and supplies for employees to perform their duties, and for EPIC Data system support.

The Facilities department's forecast $6.0 million in expenditures in the operation and maintenance of facilities in the Lower Mainland and the Interior includes $1.1 million relating to the staff required by this department. The lease costs of the floors that the Company is responsible for are included in $6.9 million of service expenditures. The offsetting recoveries relating to BC Gas subletting excess office space are forecast to be $2.0 million in 2003. The forecast includes costs associated with the lease of space at the 1111 West Georgia Street location, of which BC Gas itself is expected to occupy only three floors by the end of 2003. The 2003 gross cost (before sublet recoveries) of leased space at 1111 West Georgia Street is $2.8 million (two months related to the 7th and 8th Floor leases which expire at the end of February 2003, and a full year related to the 9th, 10th, 11th, 12th and 24th Floors). Recoveries include items related to: 1111 West Georgia Street sublet ($1.0 million); CustomerWorks Shared Services at various locations ($0.8 million); and other miscellaneous recoveries ($0.2 million).

The table below shows changes in BC Gas' facilities requirements from 1998 to 2002. The net office space the Company occupies at 1111 West Georgia Street has been reduced significantly since the completion of the Coastal Facilities project. As reflected in the table, BC Gas occupied ten floors at the 1111 West Georgia Street location in 1998, comprising approximately 150,000 sq. feet of space. Net of subleased space, this has been reduced to four floors comprising approximately 57,900 sq. feet of space in 2002. The reduction in the number of floors BC Gas occupies at 1111 West Georgia Street has helped reduce O&M costs for the Company.

Lower Mainland Facilities Requirements 1998-2002 (in Square feet)

Facility	1998	2002	Change
1111 West Georgia (Net of Sublet)	150,000	57,900	(92,100)
Gilfax	28,300	0	(28,300)
Commerce Court	29,200	6,600	(22,600)
Lochburn	151,000	95,500	(55,500)
Surrey	35,000	213,500	178,500
Total	**393,500**	**373,500**	**(20,000)**

Other benefits realized upon completion of the Coastal Facilities project include:

- the consolidation of facilities to the Surrey and Burnaby operations centres which provide the Company with key facilities to meet post-disaster design criteria to ensure continued support of operations on both sides of the Fraser River in the event of an emergency;

- a reduction in the leased space requirements at Burnaby through the elimination of the Gilfax location and a reduction at the Commerce Court location;
- enhanced work group affinities resulting from consolidation of staff and the accompanying revised work processes;
- a reduction in moving and relocation costs resulting from the long-term operational flexibility the new facilities provide;
- cost reductions resulting from the lower operating costs per square foot achieved at the new, more efficient Surrey Operations Centre; and
- the financing tool, a synthetic lease, provides the advantage of low-cost financing as well as tax benefits. BC Gas' development of a lease for the funding of the Coastal Facilities Project provides a direct benefit to customers of approximately $1.5 million per year. Since the facilities are fully financed through a debt instrument, the buildings attract no return on equity in customer rates.

The Facilities department is O&M forecast includes cost increases relating to the need for additional security at various building sites, as well as a slight increase in the cost of gas and electrical energy.

The Land Services department's forecast of $0.6 million in expenditures is required for administration activities related to property rights, including license payments and the management of property tax payments. This amount is comprised primarily of labour for the department's staff. The Company foresees significant cost pressures for property tax payments. BC Gas is projected to pay approximately $37 million in various property taxes in 2002. For 2003, BC Gas is forecasting property tax payments in excess of $41 million. Additional funding of $0.1 million within the Land Services department will allow BC Gas to retain additional resources in order to mitigate property tax cost increases.

The Legal and Risk Management department forecasts an O&M requirement of $4.9 million for 2003. Labour expenses account for $1.0 million of the total O&M required in 2003. The labour resources are comprised of the salaries for staff within the Legal and Risk Management department. The legal services group provides the general counsel, corporate and commercial legal services for the Company at a cost that is significantly less than if this work was outsourced. The risk management group is responsible for managing the

Company's insurance requirements, including claims management, and ensures the Company has effective risk management processes in place.

The remaining $3.9 million is required for a range of services and materials. These requirements are mainly comprised of insurance premiums, but also include items such as legal retainers for outside counsel, consultant fees, and stationary supplies. An appropriate level of insurance coverage is required to protect the Company from unnecessary risk and the costs associated with damage losses.

The significant cost increases related to insurance premiums warrant further discussion. The cost of insurance premiums is set in the global marketplace and these costs have increased in response to a rapidly tightening insurance market. The recent change in market conditions has been caused by a number of factors. The first of these is the relatively poor performance of a large number of Lloyd's syndicates resulting in a withdrawal of capacity from the market. This decrease in capital supply has driven an increase in insurance prices. Secondly, onshore and offshore energy risk is being written at a higher premium because of the recent industry loss record in areas such as pipeline and drilling rig failures. BC Gas' recent major loss record has worsened. The Company has experienced two insurance claims in Burns Bog, a flood loss claim in the Kootenays, and a further large claim in Quesnel relating to a gas explosion.

The most significant impact on insurance rates was as a result of the events of September 11, 2001 terrorist attacks on the World Trade Center and other locations. The impact of this tightening market is reflected in the overall 2001-2002 insurance renewal costs for BC Gas for its primary tier of insurance coverage. Furthermore, this change in market conditions has also had a significant impact on the level of deductibles. BC Gas' underwriters have increased the corporate deductible from $25,000 to $250,000 for property loss or damage and increased the business interruption waiting period from 5 days to 30 days. Major exclusions within the Primary Insurance Tier now include terrorism, flood loss ($2.25 million deductible) and any damage to the Company's pipeline facilities in Burns Bog ($5 million deductible). With respect to BC Gas' primary general liability policy, coverage remains relatively unchanged, including the deductible at $100,000. As well, the Officer / Director liability insurance has remained relatively unchanged with the exception that the BC Gas Utility allocation has been reduced to 70% from the previous 80%.

c. Historical O&M Expenditures, 1997 - 2002

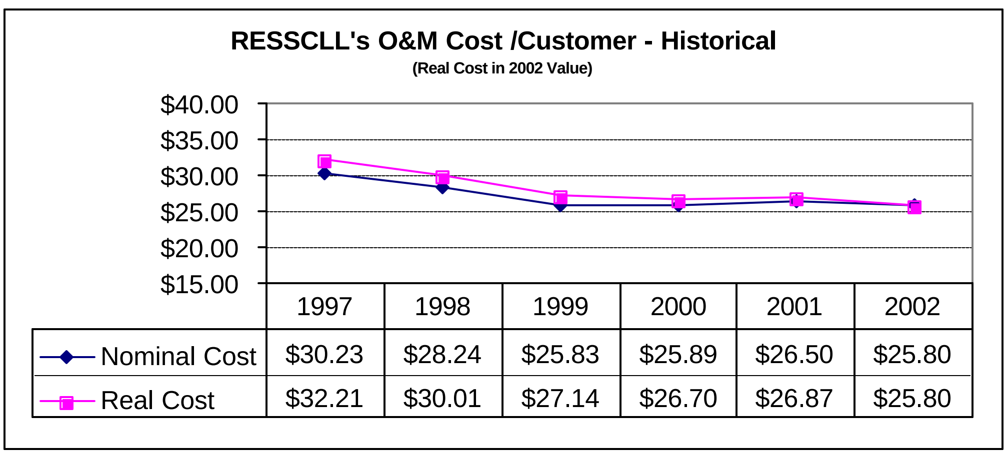
Annual O&M expenditures for 1997-2002 are summarized in the table below. On a real dollar basis, O&M costs were steadily reduced since 1997 to their current level of $19.8 million, which represents a reduction of 14.7%.

RESSCLL's Annual O&M Expenditures ($ millions)

	1997 Actuals	1998 Actuals	1999 Actuals	2000 Actuals	2001 Actuals	2002 Projected
Total Nominal O&M	**21.8**	**20.7**	**19.2**	**19.6**	**20.1**	**19.8**
Total Real O&M	**23.2**	**22.0**	**20.2**	**20.2**	**20.4**	**19.8**

Note: Real totals in 2002 values.

The staffing levels within the RESSCLL business unit were reduced from 194 FTEs in 1997 to 170 FTEs in 2002, which represents a reduction of 12.3%. This reduction was achieved mainly by outsourcing specialized non-recurring work functions. The staffing level is expected to remain unchanged for 2003.



	1997	1998	1999	2000	2001	2002
Nominal Cost	$30.23	$28.24	$25.83	$25.89	$26.50	$25.80
Real Cost	$32.21	$30.01	$27.14	$26.70	$26.87	$25.80

The above chart displays the historical O&M cost per customer and highlights the savings trend that occurred over this period. On a real dollar basis, the cost per customer was reduced by 19.9% since 1997 reflecting the actual spending reduction and customer growth during this period.

RESSCLL provides a variety of professional services and strives to provide cost-effective services without incurring added risk associated with lower service quality. A number of cost management strategies are used to deliver cost efficiencies and they involve:

- determining support activities that can be outsourced or jointly conducted with others to achieve lower costs or higher quality;
- restructuring support activities where economies of scale can be realized; and
- reviewing or redesigning support activities that BC Gas is best providing internally.

Successful implementation of these strategies have helped the departments within RESSCLL achieve the efficiencies over the last six years and will continue to be the focus of the next five years. It is becoming more difficult to realize continuing efficiencies because "easy" opportunities have already been acted on – future opportunities will involve more complex process changes and more complex technology, which will result in higher restructuring costs. With higher restructuring costs, positive payback will be a challenge to achieve.

The complexity of the regulatory environment in which BC Gas operates is considerable and the Regulatory department is responsible for responding to the requirements of customers, the Commission and other stakeholders. The working relationship between BC Gas and its stakeholders is effective, and the support of the Commission and staff has been a significant contributor to the productivity of the group. The results have benefited customers through the development and enhancement of an effective regulatory process.

The Environment, Health and Safety department has developed an environmental management system that, although not certified as such, is ISO-14001 compliant. This compliance has been confirmed by an outside agency that has expertise in certification. In addition, the audit function performed within this department has been expanded to include safety with no incremental increase in headcount.

BC Gas is also a leader in the area of emergency planning for the province of British Columbia. This leadership role and related best practice in emergency response benefits the general public and BC Gas customers considerably. While the Company has minimized its employee levels, it has maintained a high level of diligence in its ability to respond to emergencies. All employees participate in various corporate emergency exercises. In addition, employees participate in larger emergency planning exercises with all relevant government and non-governmental agencies in the province of British Columbia. The development and co-ordination of BC Gas' emergency planning and readiness relies on staff who have developed high level expertise and credibility within the disaster response planning community. In addition to the capability of its employees, the Surrey Operations Centre, which was recently completed, has also been constructed to post-disaster specifications and has been designed to increase the likelihood of continued operations throughout a disaster.

Efforts by this department have resulted in BC Gas receiving recognition from various external parties – some of these are listed here:

- Canada's Climate Change / Voluntary Challenge Registry - BC Gas has been a Gold Level Reporter for the last three years and, in March of 2002, received the Leadership Award for the Canadian Oil and Gas Sector for its efforts towards Green House Gas Management and Emissions Reduction; and

- Desjardins Environmental Fund (DEF) - BC Gas shares are traded within the DEF equity investment fund. BC Gas is recognized as a company whose philosophy contributes to preservation of the environment and has implemented concrete methods to manage the environmental impact of BC Gas' activities (as defined in the *Canadian Environmental Assessment Act*).

The fleet services section of the Supply Chain and Logistics department rationalized BC Gas' vehicle fleet and obtained an overall reduction; the size of the fleet decreased from 625 vehicles in 1999 to its current size of approximately 519 vehicles. As well, most of the fleet services administration was outsourced to B.C. Hydro resulting in a savings of approximately $0.4 million per year in O&M costs.

The vehicle and equipment lease agreement with B.C. Hydro is currently in the fourth year of a five-year contract that expires on December 31, 2003. This agreement, covering approximately $7.7 million in fleet services for 2002, was the result of a contractual obligation associated with the privatization of the B.C. Hydro Gas Division – this obligation ends with the current contract. The fleet services for BC Gas will be tendered at the end of this agreement.

Since 1997, the mechanical services section completed a consolidation of the Metro and Fraser Valley shops that eliminated process duplication and resulted in savings of approximately $0.4 million per year. Reductions were achieved in manpower, shop tools and equipment, consumable materials, and steel and pipe fitting inventories. In addition, indirect savings related to building heat, light, and maintenance were also realized.

Cost efficiencies related to the development of economies of scale have been developed within the Supply Chain and Logistics group. Within the last couple of years, the department helped found the Consolidated Buying Group ("CBG") with other members of the utility industry, which include Duke Energy, TransCanada and Union Gas. The benefit of participation has been to realize economies of scale related savings on the procurement of materials and services. Through the aggregation of purchases with other members of the CBG, the Company has been able to obtain lower unit costs associated with larger purchase volumes of gas system materials. The buying group will continue to negotiate contracts for the purchase of other materials and services but the change in ownership of Duke creates some doubt on future strategic sourcing initiatives.

The Facilities department follows the generally accepted industry approach to facilities operations by striking a balance between the amount of work contracted outside the Company and work performed by in-house employees. The most cost-effective combination for BC Gas has been to utilize its own employees to perform the preventative maintenance inspections and to outsource the service work requiring special expertise. In addition, the high-efficiency designs incorporated into the Surrey operations and multi-purpose buildings are part of the efforts by BC Gas to reduce costs related to operating its own buildings. The Company submitted, and received recognition from the Commercial Building Incentive Program (CBIP) for two buildings at the Surrey site. The Surrey Operations Building and the adjacent Education Building were designed to meet energy efficiency targets of 69.0% and 71.5%, respectively, of normal energy usage for buildings constructed to the Model National Energy Code for Buildings.

The Legal and Risk Management department has managed their controllable costs effectively. Costs related to the legal services functions have remained relatively unchanged throughout 1997-2002. Risk management and insurance services costs remained stable from 1997-2001, however, in 2002 and beyond increases related to insurance premium costs will occur.

d. Forecast O&M Expenditures, 2003 - 2007

The funding requirements for RESSCLL for the five-year period covering 2003-2007 are set out in the table below.

RESSCLL's Annual O&M Expenditures ($ millions)

	2002 Projected	2003 Forecast	2004 Forecast	2005 Forecast	2006 Forecast	2007 Forecast
Total Nominal O&M	**19.8**	**21.3**	**24.1**	**24.9**	**26.1**	**27.4**
Total Real O&M	**19.8**	**21.0**	**23.3**	**23.5**	**24.2**	**24.9**

Note: Real totals in 2002 values.

Incremental O&M funding requirements beyond the 2003 level are being driven by the following cost pressures:

- The insurance premiums related to both basic coverage and umbrella coverage are forecast to increase substantially over the next five years. As the Company's annual insurance contract does not coincide with the calendar year, the 2003 forecast only included a portion of the full premium increases. In 2004, the balance of the annual premium increases, an additional $2.1 million, is included. Further cost pressures, amounting to approximately 10% per year, on the basic and umbrella coverage premiums are expected throughout 2005-2007.

- Facilities operations for 2003 included incremental security and utility costs. The increased security costs relate to the need for enhanced security requirements at various BC Gas offices. In order to reduce the cost impact to customers, the program is being phased in over the next two years and the 2004 forecast includes the funding for the second phase. The utility costs for the Company's offices, based on the current consumption patterns and the five-year forecast of gas and electrical energy costs, are subject to minor cost pressures after 2003.

- The 2003 forecast included cost savings related to a reduction in the number of floors the Company will occupy at the 1111 West Georgia Street location. BC Gas will utilize three floors at the end of 2003 with further reductions expected over subsequent years. By the end of 2005, BC Gas will occupy only two floors – delivering cost savings well in excess of those proposed under the Coastal Facilities CPCN business case.

- The O&M expenditures are subject to annual labour and general inflation and, as such, these components contribute to the cost pressures facing the business unit over the next five years.

Looking beyond 2003, RESSCLL faces significant cost pressures in several key areas. The most significant costs pressures tend to be the result of external factors which BC Gas cannot control or influence. The global insurance market is the primary driver of cost increases within RESSCLL and there is risk of even greater cost pressures in this area. Furthermore, the regulatory compliance-based activities performed within the business unit are subject to cost pressures resulting from changes to existing legislation and regulation – these pressures have not been included in the five-year forecast and comprise a portion of the risks being assumed by the Company.

6. FINANCE

This area is comprised of the following departments: Operations Finance, Financial Accounting and Reporting, Tax Services, Treasury Services, Financial Development and Planning and Internal Audit. Their responsibilities are described below.

The Operations Finance group is comprised of the field operations accounting group and the financial performance accounting group which is responsible for the areas of budgeting, monthly management reporting, performance measurement, monthly variance analyses and year-end forecasting, and control of capital expenditures and assets. It also includes a clerical group that performs transaction accounting: construction job costing, work wage time entry for employees, miscellaneous accounts receivable, and third party cost recoveries.

The Financial Accounting and Reporting group is responsible for the accounting and preparation of external financial statements for BC Gas. This department has the overall responsibility for developing corporate financial accounting policies and procedures, reviewing and maintaining the Code of General Ledger Accounts and ensuring compliance with regulatory reporting. It is also responsible for the accounting for gas revenues and cost of gas accruals, accounting for deferral accounts, preparation of bank deposits, reconciliation of bank accounts, and maintaining the accounts of continuing service charges and billing of inter-company charges.

The Tax Services group is responsible for compliance with federal and provincial income tax, capital tax, and commodity tax statutes, including preparing tax returns, advising on required tax instalments, advising on application of GST and PST to transactions, and dealing with CCRA and provincial audits. This group also prepares tax estimates for financial reporting and regulatory reporting purposes and ensures that the company minimizes taxes payable through research and tax planning.

The Treasury Services department's purpose is to provide corporate finance services, corporate financial risk management, financial market operations, cash management, and investor relations. It is responsible for managing the capital raising activities of the Company, including the Medium Term Note program, short-term borrowings, bank credit facilities, and other corporate financing, and developing the long range financing plans. This group also provides investor relations services, including interaction with analysts, preparation of documents such as the Annual Information Form, quarterly reports, bond rating presentations, and material for investor presentations and road shows.

The Tax Services, Treasury Services and Financial Development and Planning groups work closely together to provide a variety of value-added advisory services to business units and develop structures to minimize the tax and financing costs of the Company. These employees work with other departments to bring different financial skill sets to bear on business issues and opportunities. This group has implemented several initiatives in recent years. They include: development of a financing structure in conjunction with the Southern Crossing Pipeline project, implementation of the synthetic lease transaction for the Coastal Facilities project, and the implementation of the Lease-in Lease-out (LILO) transaction with the municipality of Kelowna.

Internal Audit provides assurance to the Board of Directors and senior management that business risks are being appropriately managed and that the control environment effectively supports the organization in attaining its objectives. This group is responsible for ensuring major projects are reviewed on a regular basis at all stages of the project. Internal Audit also undertakes certain work on behalf of the BCUC on an annual basis (e.g. Review of Financial Directions and Orders and Summary of Internal Audit Reports) and, from time to time, other projects on a special request basis. The types of services provided by Internal Audit include control assurance activities (internal audits and control risk assessments), consulting and advisory activities, post-implementation reviews of major projects, information technology reviews and compliance activities.

a. Cost Drivers

The primary cost driver faced by Finance is labour inflation. Labour costs comprise a significant portion of total O&M costs, which face upward pressure in line with increases in the rate of inflation. Another cost driver faced by Finance is the need to respond to changing financial and accounting rules. Changes in these rules affect both the preparation of the Company's financial statements, as well as, requiring changes for numerous accounting processes and procedures.

b. 2003 Forecast O&M Expenditures by Finance

The following table shows the breakdown of expenses of the Finance departments and the corresponding number of full time equivalents (FTEs) for 2003 and other expenses included in the O&M expenses.

O&M Forecast - Finance ($ millions)

Component	2003
Operations Finance	2.6
Financial Accounting & Reporting	1.0
Tax & Treasury Services, & Financial Development & Planning	2.1
Internal Audit	0.5
Subtotal	**6.2**
Other Post-Employment Benefits (OPEBs)	6.1
Total O&M	**12.3**

The total operating budget (excluding OPEBs) for the Finance department of $6.2 million is comprised of the following: $4.6 million pertains to compensation and related costs for the 65.7 full time equivalent staff. The employee group is a mix of professional accountants and other analysts (Chartered Accountants, Tax specialists, Chartered Financial Analysts, Certified General Accountants, Certified Management Accountants, and Certified Internal Auditors) and clerical and administrative staff. $1.1 million relates to audit fees, accounting and tax services, shareholder expenses, bank charges and credit rating agency fees. The remaining $0.5 million is comprised of employee training costs, travel expenses to support interior operations, miscellaneous administrative costs, materials and supplies, and professional membership dues.

The Canadian Institute of Chartered Accountants issued new standards which required Canadian companies to accrue obligations under employee benefit plans as the underlying services are provided (see Tab E, Accounting Policies and Procedures for further discussion of this item). As such, the costs of Other Post-employment benefits for all employees are included as part of the Company's O&M expenditures which are reflected in this section.

c. Historical O&M Expenditures, 1997 - 2002

Since 1997, there have been three significant changes to the Finance group. Through the implementation of the SAP financial system in 1998, there have been substantial headcount reductions in most areas in Finance, resulting in a reduction of 32 FTEs. In 1999, the responsibility of the Accounts Payable function was transferred to another business unit and is currently within Supply Chain and Logistics. On October 2001, the Enterprise Resource Planning (ERP) group which was responsible for supporting users in the business process areas, ensuring the stability of the SAP system and participating in the upgrading and enhancements of systems, was transferred to the Information Technology Services group.

The remaining departments under Finance have remained relatively unchanged since 1997. The table below shows the historical costs of this area restated for the organizational transfers noted above. Other O&M expenses included in this area include the accounting for other post employment benefits (OPEBs) as noted previously.

Finance's Annual O&M Expenditures ($ millions)

	1997 Actuals	**1998** Actuals	**1999** Actuals	**2000** Actuals	**2001** Actuals	**2002** Projected
Financial Services	8.3	7.7	6.8	6.6	6.7	6.1
OPEBs				2.5	4.6	5.0
Total Nominal O&M	**8.3**	**7.7**	**6.8**	**9.1**	**11.3**	**11.1**
Total Real O&M	**8.8**	**8.2**	**7.2**	**9.4**	**11.5**	**11.1**

Note: Real totals in 2002 values.

Total operating costs for the Finance business unit have decreased by 20% from 1997 to 2001 mainly as a result of the implementation of SAP as discussed further below. There has been a further decrease in 2002 as BC Gas finance employees charge more Continuing Services hours to BC Gas Inc. and its subsidiaries, such as Centra Gas and CustomerWorks. The cost of stock options was higher in 2001 due to the higher range in the stock price throughout that year. See Tab E, Accounting Policies and Procedures for further discussion in the charges incurred for stock options. The increase in OPEBs reflects the higher costs of future employee benefits.

The following summarizes the benefits that were achieved through the implementation of SAP financial system:

Financial Performance Accounting – several positions were eliminated in this group since SAP allows for the decentralization of capital project creation and maintenance throughout the organization. SAP also allows for more detailed automated storage of data. Therefore, ad hoc requests by various groups throughout the organization can be dealt with quickly by Financial Performance Accounting as the data is readily available. In the past, this would have required a great deal of manual effort to compile. In the area of budgeting, the aggregation of data is largely automated. Only two staff are now required to oversee the O&M and capital budgeting and reporting process.

Operations Accounting & Operations Finance – A number of positions in the area of wage time entry, job costing and financial analysis were eliminated from these groups. The reductions were made possible due to improvements in the transaction processing areas and improved management reporting capabilities, thereby, reducing the reliance of operations groups on the analytical support groups. Further improvements are required in this area and are being pursued as part of the Process Reporting project and Business Warehouse initiatives currently underway.

d. Forecast O&M Expenditures, 2002 - 2007

The table below summarizes the Finance O&M budget for 2003-2007.

Finance's Annual O&M Expenditures ($ millions)

	2002 Projected	2003 Forecast	2004 Forecast	2005 Forecast	2006 Forecast	2007 Forecast
Financial Services	6.1	6.2	6.4	6.5	6.7	7.0
OPEBs	5.0	6.1	6.2	6.5	6.7	6.9
Total Nominal O&M	**11.1**	**12.3**	**12.6**	**13.0**	**13.4**	**13.9**
Total Real O&M	**11.1**	**12.1**	**12.2**	**12.3**	**12.4**	**12.7**

Note: Real totals in 2002 values.

2003 staffing levels are budgeted unchanged against 2002 levels with only inflationary increases being allowed in the 2003 budget for the group. In real terms forecast expenditures are expected to remain flat against the 2002 levels. The level of expenditure is generally expected to remain the same plus labour and general inflation during that period.

In 2002 the Company launched the Process Reporting and Performance Measurement initiative to meet the needs for enhanced management planning, budgeting and analysis tools to support the business. The project includes implemention of the Business Warehouse module of SAP later this year. The Business Warehouse module will allow BC Gas to further harness the power of the SAP infrastructure and enhance the reporting and management information provided to the organization but is not expected to reduce expenditure levels. BC Gas anticipates reinvesting any efficiency gains relating to streamlining and automation of the enhanced reporting capabilities to provide additional support to the organization and reduce staff overtime. The Tax Services, Financial Development and Planning, and Financial Accounting and Reporting groups are also operating under a streamlined staffing level after the implementation of SAP. In addition there is a trend towards greater levels of governance and accounting disclosure requirements that will increase the workload for these groups. This will also add pressure on audit fees and outside tax and accounting service charges. Nevertheless, these groups are expected to maintain their current level of expenditures through continuous reviews and improvements of internal processes.

The Treasury Services group faces a number of cost pressures over the next few years. For example, the move by U.S. rating agencies into the Canadian market (e.g. Standard & Poor's purchase of CBRS) is causing inexpensive Canadian rating fee scales to be replaced by more expensive U.S. fees. The Company must pay these fees as BC Gas' credit ratings are preconditions for capital markets access. BC Gas is also facing increasing demands by regulatory authorities for fuller and broader disclosure which creates additional costs, both in terms of labour as well as the costs of supporting communication channels (e.g. internet site, webcasting, etc.). Notwithstanding these challenges, the Treasury Services group is continually trying to find efficiencies that will allow them to maintain a constant level of overall operating expense.

The Internal Audit budget for 2003 is $0.5 million. This budget remains virtually unchanged from the 2002 level. The 2003 budget includes compensation and related employee expenses (e.g. training and membership dues) for six employees including a Director, two Senior Auditors, a Project Review Specialist, a Senior Information Technology Auditor and an Audit Services Co-ordinator. These resources are currently considered adequate to support coverage of the Company in a manner that supports the level of assurance concerning risks and controls required by the Audit Committee and senior management. The scope of audit activities will increase in light of the increased focus on risk management and corporate governance as evidenced by the March 2001 report issued by the Joint Committee on Corporate Governance (the "Saucier Committee"). This will entail the evaluation of the effectiveness of corporate governance and risk management processes within BC Gas, as well as contributing to the improvement of these processes. Thus, there will be incremental pressures on the operating expenditures of Internal Audit as only labour and general inflation have been added for the periods 2003-2007.

The major increase in O&M expenses from the 2002 level of expenditures is the $0.9 million increase in OPEB as calculated by the Company's actuarial firm. The primary reason for this is due to the increase in MSP premiums announced this year.

Finance focuses on completing a range of critical responsibilities that include the control of budgeting, management and financial reporting; the development and review of financial accounting policies and procedures; compliance with taxation requirements; and completing financial market requirements. These responsibilities must be met in the face of changing financial and accounting standards. The Finance group believes that the forecast level of O&M expenditures are prudent and necessary.

7. INFORMATION TECHNOLOGY SERVICES (“ITS”)

ITS is the business unit responsible for the planning and delivery of information technology services to the Company. ITS’ primary goal is to provide enabling technologies ensuring that other business units in the Company function effectively and efficiently. In order to meet this objective, ITS ensures that the Company’s data is compatible with that available from industry; that data is accessible throughout the Company; and that information technology infrastructure platforms (Wide Area Networks, Local Area Networks, servers, desktops, laptops, printers, firewalls, anti-virus and intrusion detection services, etc.) are managed across business units. These platforms are designed to enhance the productivity and effectiveness of business processes, as well as meeting security requirements. Adequate security is critical to ensuring that business processes, employees, and customers are protected. Effective IT management mitigates the risk of system outages that impacting critical business processes.

ITS is also responsible for the life-cycle management of all business applications. Working with the Company’s business units, ITS validates business cases which set out project benefits prior to the expenditure of capital resources, leads in the acquisition of resources (both financial and personnel), and in the designing, building, testing and implementation of business systems. Life-cycle-management responsibilities also include ensuring that business applications operate reliably. Finally, ITS is responsible for the Company’s overall IT strategic plan which incorporates the need for business applications and the underlying infrastructure required to support these applications. This plan ensures that IT expenditures are made prudently through a co-ordinated view of Company’s needs and by appropriate priority setting.

ITS is organized into two main IT service delivery departments, Applications Management and IT Infrastructure Management, and is led by the Office of the CIO. Attached to this office is the Capital Management Office (CMO), which is responsible for co-ordinating and managing the Company’s capital expenditures.

Current staffing levels of 52 FTE’s represent an approximate 20% reduction from peak staffing over the last five years, as increasingly greater portions of the Company’s IT requirements have been outsourced.

a. Cost Drivers

The key cost driver affecting ITS' O&M expenditures is the cost of supporting and maintaining the applications that have been implemented in the Company, plus the infrastructure required to operate the applications. In this regard the largest driver of future O&M costs relates to the short life of technology, especially where products are abandoned by vendors or applications that require frequent upgrades; the considerably larger IT infrastructure that needs to be maintained; the growing number of applications, including middleware, that need to be supported; and the need to ensure that software licenses are kept current. Although internal labour costs represent a declining portion of total O&M costs, general labour inflation and the need to recruit and retain skilled employees is also a key cost driver. Given the Company's outsourcing strategy, a key cost driver for the ITS group is that of increasing consulting costs. ITS continually revisits the outsourcing strategy and makes key hiring decisions to ensure the best balance of internal and external costs.

ITS market tests a significant potion of its applications and infrastructure support requirements on a regular basis in order to ensure cost-competitiveness. This is achieved by comparing the Company's IT cost structure with industry information. This analysis helps to identify opportunities for cost and process improvement. ITS draws on a mix of large third party IT providers and smaller contractors to ensure that the most competitive costs are realized.

b. Forecast O&M 2003 Expenditures for ITS

The forecast 2003 operating and maintenance budget for ITS is $14.6 million. From a resource perspective, ITS' cost structure is comprised of $4.1 million in labour expenses which represents 28% of total O&M, and remaining $10.4 million, or 72%, is mostly for outsource contracts. These outsource contracts are tendered and have recently been market tested to ensure the Company obtains the best value. The following table sets out a summary of forecast cost by functional area and major resource group. The forecast expenditure for each functional area is also broken out by major resource group.

O&M Forecast - ITS ($ millions)

Functional Area	2003
Applications Mgmt	
Labour	2.1
Contracts	5.5
Services & Supplies	0.3
Revenue	(0.2)
Subtotal	**7.7**
IT Infrastructure Mgmt & CIO/CMO	
Labour	2.1
Contracts	5.7
Services & Supplies	0.2
Revenue	(1.0)
Subtotal	**6.9**
Total O&M	14.6

Applications Management is primarily responsible for the support and sustainment of all major business applications, as well as support for the Company's databases. This group is also responsible for the evaluation of new applications and the contracting and management of third party consulting companies for application development and maintenance. A staff level of 30 FTEs provide these services. In order to deliver these services Applications Management forecasts an O&M requirement of $7.7 million in 2003. Of this total, labour costs represent $2.1 million for the 30 staff. The largest cost component is represented by outsourcing contracts totalling $5.5 million. This amount is comprised of agreements with third parties for the support and maintenance of the Company's applications, as well as costs for third party consulting companies. The remaining requirements total $0.3 million and are comprised of miscellaneous services, office supplies, and employee expenses. The total of these requirements is offset by revenue of $0.2 million earned from the provision of IT services to CustomerWorks.

IT Infrastructure Management is responsible for the design, installation, and management of the Company's network. Additional responsibilities include security management relating to network access, e-mail and Internet operation, and anti-virus protection. IT Infrastructure Management is also responsible for support of the Company's SCADA and radio system networks. Attached to this group for budgeting purposes is the Office of the CIO and the Capital Management Office. These functions are responsible for the overall management of the ITS business unit, as well as co-ordinating and managing the Company's capital spending program. A staff of 22 FTEs deliver the services described above. IT Infrastructure Management forecasts an O&M requirement of $6.9 million for 2003. Of this total, labour costs are $2.1 million for the 22 staffs. The largest component is comprised of contract costs totalling $5.7 million and is for outsourcing agreements negotiated with third parties for support and maintenance of the Company's networks. The remaining requirements for $0.2 million include miscellaneous services, office supplies, and employee expenses. The total of these requirements is offset by $1.0 million in revenue earned from the provision of services to the CustomerWorks as part of the Shared Services Agreement with this company.

Overall, the $14.6 million forecast level of expenditures in 2003 represents an increase of $1.0 million between 2002 and 2003. IT Infrastructure Management O&M spending is driven by the need to maintain a growing number of applications as well as equipment related to internet linked communications with customers. Customer requirements have contributed to the cumulative investment in systems over the last five years. For 2003, customer driven increases include $0.3 million attributable to applications in the Gas Supply & Transmission business unit which enables customers to access real time market information, increased customization and more detailed reporting; $0.1 million is required by the Marketing Business Unit to support requirements for industrial customers; and approximately $0.3 million is required to address need for additional servers to ensure that system security and reliability (specifically the Disaster Recovery Plan – DRP) and to offset Radio Canada mandated radio frequency license cost increases required to operate the Company's radio network. The remaining $0.3 million increase is attributable to inflation.

c. Historical O&M Expenditures, 1997 - 2002

In 2002 ITS' O&M expenditures are projected to be $13.5 million. Total O&M spending over the past five years on ITS' services declined after reaching a peak in real terms in 1999. This is illustrated in the table below that sets out O&M actual spending since 1997 and projected spending for 2002.

ITS' Annual O&M Expenditures ($ millions)

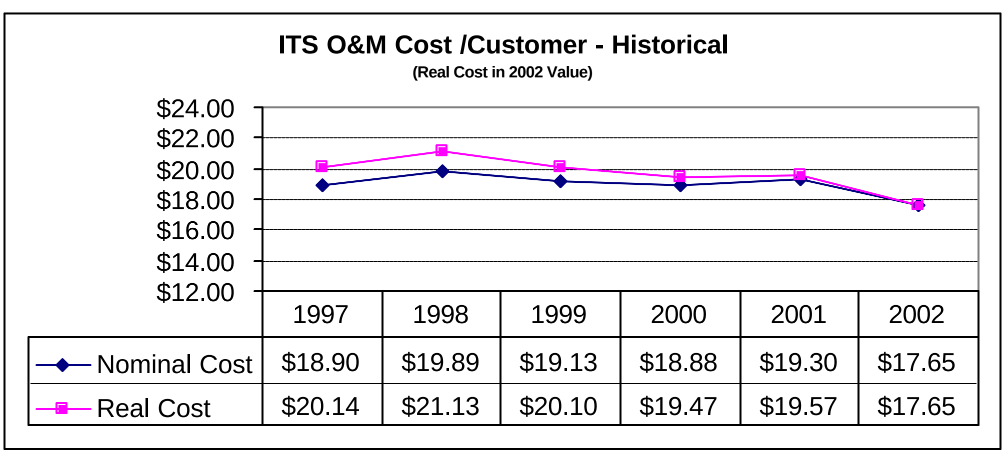
	1997 Actuals	1998 Actuals	1999 Actuals	2000 Actuals	2001 Actuals	2002 Projected
Total Nominal O&M	**13.6**	**14.6**	**14.3**	**14.3**	**14.7**	**13.5**
Total Real O&M	**14.5**	**15.5**	**15.0**	**14.7**	**14.9**	**13.5**

Note: Real totals in 2002 values.

The increase in O&M expenditures between 1997 and 1998 is attributable to the additional support required after the implementation of a number of new major applications, the most significant of which was the SAP system. Real O&M spending on IT services declined after 1998 by approximately $0.6 million to $14.9 million in 2001(4.0%). This decrease is primarily attributable to efficiency improvements realized during this period. These costs were reduced through a combination of new and renegotiated outsourcing agreements, as well as process improvements that resulted in staff reductions. Achieving these efficiencies has been a challenge during a period when ITS assumed sustainment responsibility for a range of new applications. The benefits of these new applications are included in the O&M in other business units.

The reduction in 2002 is attributable to the Shared Services agreement with CustomerWorks. This agreement created a revenue stream in 2002 of $1.2 million that offsets ITS O&M costs.

An overview of IT costs per customer provides another perspective on the effectiveness of cost management by BC Gas over the least five years.



The chart above shows that customers were the beneficiaries of efficiency gains since 1997 through reduced O&M costs. The real O&M cost per customer decreased slightly from

$20.14 in 1997 to $19.57 in 2001, representing savings of 2.8%. The further decline of approximately 10% in 2002 to $17.65 is a result of the sale of IT services to CustomerWorks and represents a benefit of this outsourcing arrangement. Successfully implementing these outsourcing and process improvement strategies has allowed ITS to improve service delivery efficiencies through the last five years and will be the focus for the business unit in the future. However, it is becoming more difficult to realize continuing efficiencies because accessible and readily apparent opportunities have already been acted upon. Future opportunities will involve more complex process changes and more complex technology.

Expanded use of the Internet by customers, stakeholders and employees and the accompanying customer expectations around automatic meter reading (AMR) and e-business has also been challenging. These technologies require significant infrastructure and ongoing maintenance as well as the need for real-time updating of data.

d. Forecast O&M Expenditures, 2003 - 2007

ITS' forecast O&M expenditures over the next five years are set out in the table below.

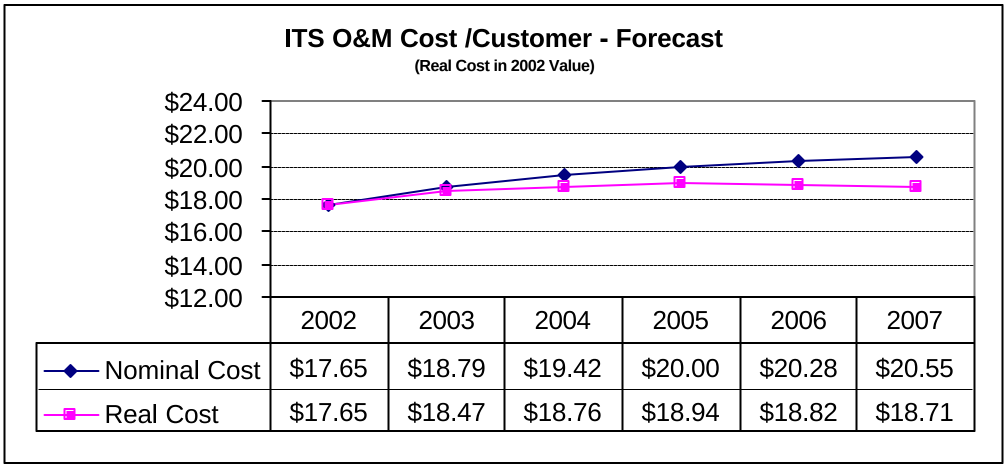
ITS' Annual O&M Expenditures ($ millions)

	2002 Projected	2003 Forecast	2004 Forecast	2005 Forecast	2006 Forecast	2007 Forecast
Total Nominal O&M	**13.5**	**14.6**	**15.2**	**15.8**	**16.2**	**16.7**
Total Real O&M	**13.5**	**14.3**	**14.7**	**15.0**	**15.1**	**15.2**

Note: Real totals in 2002 values.

As explained earlier, O&M expenditures are expected to increase by $1.0 million in 2003 over the level projected in 2002. Including inflation the total increase for over the next five years is forecast to be $2.1 million, or 14.4% between 2003 and 2007. Adjusting for the effects of inflation, this represents a real increase of 6.3%.

The following chart compares this forecast on a real dollar O&M cost per customer basis and shows a slight forecast increase between 2003 and 2007.



	2002	2003	2004	2005	2006	2007
Nominal Cost	$17.65	$18.79	$19.42	$20.00	$20.28	$20.55
Real Cost	$17.65	$18.47	$18.76	$18.94	$18.82	$18.71

Compared with the previous five-year period, the forecast real dollar cost per customer over the next five years represents a decline.

ITS' five-year forecast does not foresee significant cost increases beyond 2003 after adjusting for the effect of inflation. For 2004 the only non-inflationary increases forecast by ITS is $325,000 in additional server and applications support, and licensing costs. For 2005 the non-inflationary increases identified are $235,000 in additional radio licensing, applications licensing costs, and server support. There are no non-inflationary expenses included in the forecast for 2006 and 2007.

ITS will continue to focus on the effective delivery of IT services over the next five years. During 1997-2002, ITS realized significant efficiencies through the introduction of the major applications in use today. The forecast O&M expenditure of $14.6 million for 2003 is required in order to manage, maintain, and support the IT infrastructure of the Company. Looking forward, technology replacement and enhanced security requirements will present the Company with the most significant challenges.

8. CEO & PRESIDENT BC GAS UTILITY

The CEO and President's offices are responsible for the overall management of the Utility and for providing the overall leadership to execute the strategic plan. This office ensures that resources are employed efficiently and effectively across all business units to ensure that customers receive value in the rates they pay for the safe, reliable and efficient delivery of natural gas. The budget includes the compensation for the senior executives of the Utility, their assistants and the Government Affairs group and the incentive plans for the M&E group. It also includes the corporate and administrative costs required to run the Utility.

a. 2003 Forecast CEO & President O&M

The 2003 forecast O&M for this area is $9.3 million. Included in this amount is $6.7 million for compensation for senior executives, their assistants, two employees for the Government Affairs group, and all short term and long term incentives for all M&E employees, including the cost of stock options. The remaining amount is composed of a number of items including directors' fees and expenses, membership dues, corporate sponsorships and donations, communication expenses, consulting fees, travel and training, and other miscellaneous office and administrative expenses.

b. Historical O&M Expenditures, 1997 - 2002

Costs in the CEO & President budget have generally been declining in both real and nominal terms over that last five years with the exception of 1998. The increase in 1998 is due to reorganization costs resulting from organizational restructuring initiatives.

The tables below summarize the CEO & President O&M costs, both historically and forecast.

CEO & President's Annual O&M Expenditures ($ millions)

	1997 Actuals	**1998** Actuals	**1999** Actuals	**2000** Actuals	**2001** Actuals	**2002** Projected
Total Nominal O&M	**7.7**	**9.7**	**7.8**	**8.7**	**11.1**	**9.3**
Total Real O&M	**8.2**	**10.3**	**8.2**	**8.9**	**11.3**	**9.3**

Note: Real totals in 2002 values.

c. Forecast O&M Expenditures, 2002 - 2007

CEO & President's Annual O&M Expenditures ($ millions)

	2002 Projected	2003 Forecast	2004 Forecast	2005 Forecast	2006 Forecast	2007 Forecast
Total Nominal O&M	**9.3**	**9.4**	**9.6**	**9.8**	**10.0**	**10.3**
Total Real O&M	**9.3**	**9.2**	**9.2**	**9.3**	**9.3**	**9.3**

Note: Real totals in 2002 values.

2003 staffing levels are budgeted unchanged against 2002 levels with only inflationary increases allowed in the 2003 budget for the group. In real terms the 2003 expenditures are expected to remain at the 2002 levels. The level of expenditure during the period 2003 through 2007 is generally expected to remain the same plus labour and general inflation.

9. HUMAN RESOURCES

The goal of the Human Resources group is to ensure that the Company's workforce is of a quality and quantity to achieve the Company's objectives. This is accomplished by ensuring its hiring practices, labour relations strategies, training and development programs, total compensation programs, and the associated processes and systems to support them, are effective and efficient.

Three broad Human Resources strategies support the Company's goals:

- continue to foster a work culture that is characterised by all employees having a greater sense of accountability and ownership in the Company;
- create and implement a customer-focussed labour relations strategy; and
- provide value-based, human resources services to support operational excellence in the various departments of the Company.

The Human Resources Department is comprised of four main functional areas:

- Labour Relations;
- Trades Training and Organizational Development;
- Total Compensation (pension, salary, incentive, and benefit plans); and
- Administration and Advisory Services (payroll, employee records and reporting, and recruiting full-time and temporary employees).

These four functional areas provide the following services:

- staffing (sourcing, shortlisting, interviewing and hiring candidates for vacancies);
- payroll services, including reporting and records;
- benefits enrolment and administration and claims management including negotiating and managing contracts with insurance companies;
- pension plan administration involving two registered pension plans;
- compensation design and administration, including base and incentive pay programs;

- labour relations including negotiating collective agreements, contract administration and interpretations, grievance handling, and training;
- trades training services including the development and delivery of mandatory training to employees involved in the safe installation and maintenance of the gas distribution system;
- training administration and record keeping of all training delivered to employees;
- employee advisory and organizational development services including performance management, succession planning, leadership development and change management; and
- human resource information system (HRIS) management and operation, including developing and maintaining employee resource information on the Company's Intranet.

a. Cost Drivers

The key cost driver affecting Human Resources' O&M expenditures is the level of staffing required to deliver services. Given that approximately 86% of Human Resources O&M costs are comprised of labour expenses, increases in demand for the services provided by this business unit tends to place upward pressure on these expenses. Labour costs are also driven by increases in benefits costs and the need to replace skilled employees that leave the Company. These drivers manifest themselves in the form of labour inflation. For 2003, and forecast expenditures beyond this, labour inflation is the most significant cost driver for Human Resources.

b. Forecast 2003 O&M Expenditures by Human Resources

The forecast 2003 operating and maintenance expenditures for Human Resources are $5.3 million. From a resource perspective, Human Resources' cost structure is comprised of $4.6 million in labour expenses which represents 86% of total O&M, and $0.7 million in contracts, services, materials, and supplies representing the remaining 14%.

The following table sets out a summary of this forecast by functional area.

O&M Forecast - HR ($ millions)

Functional Area	2003
Labour Relations	
Labour	0.3
Other Labour	0.2
Services & Supplies	0.1
Subtotal	**0.6**
Trades Training & Org Development	
Labour	1.4
Services & Supplies	0.3
Subtotal	**1.7**
Total Compensation	
Labour	0.6
Other Labour	0.6
Services & Supplies	0.1
Subtotal	**1.3**
Administration & Advisory Services	
Labour	1.6
Services & Supplies	0.4
Revenue	(0.2)
Subtotal	**1.7**
Total O&M	**5.3**

Labour Relations is primarily responsible for the negotiation of the Company's collective agreements, contract administration and interpretation of these agreements, and grievance handling. As work processes change and restructuring of jobs result, this area is also responsible for managing the lay-off and "bumping" process, negotiating job changes with the Company's unions, managing grievances, and assisting line managers to plan and implement changes in bargaining unit jobs. A staff of 4 FTEs and third party consultants delivers these services.

Trades Training and Organizational Development is responsible for the development and delivery of mandatory training to employees involved in the safe installation and maintenance of the gas distribution system. In addition, this group manages training administration and record keeping for all training delivered to the Company's employees. This group is also responsible for the development and implementation of performance management, succession planning, leadership development and change management programs. 19 FTEs deliver these services. Trades Training and Organizational Development forecasts a total O&M requirement of $1.7million. Of this total, the largest is comprised of labour of $1.4 million. The balance of this department's requirements is comprised of expenditures for vehicles required by the instructors for the delivery of trades training to the Company's employees, external consultants required for the development of courses, and for office supplies and employee expenses.

Total Compensation is responsible for compensation design and administration, including base and incentive pay programs. This group is also responsible for benefits enrolment and administration, long-term disability claims management, and negotiating and managing insurance contracts. It also administers the Company's two registered pension plans. These services are delivered by 8 FTEs. The 2003 O&M requirement for the Total Compensation group is forecast to be $1.3 million. Of this total Labour represents approximately $600,000. The $600,000 required for Other Labour represents an increase in benefits costs. This cost is primarily comprised of a 32% increase in MSP premiums and a 33% increase in long-term disability coverage. The 2003 budget also provides for third party consultants required to validate the Company's compensation and pension plan program design to ensure market competitiveness, administration of certain aspects of pensions and compensation and for office supplies, employee training and travel and expenses incurred by this group's staff.

Administration and Advisory Services is responsible for the delivery of human resources services to the Company's employees. Services delivered by this group include the sourcing and hiring of employees, employee advisory services such as day-to-day support to managers in insuring individual performance plans are in place and that performance problems are dealt with promptly and efficiently, and payroll including reporting and records. Administration and Advisory Services is also responsible for the management and operation of the human resources information system and maintaining employee resource information on the Company's Intranet. A staff level of 21 FTEs delivers these services. Administration and Advisory Services forecasts a total O&M requirement of $1.7 million for 2003. The largest component of this total is labour at $1.6 million for the 21 FTEs. The next largest amount is $0.4 million and is comprised primarily of external consulting requirements (i.e. Workplace Harassment policies, investigations and training); and expenses for office supplies, employee training, travel and expenses, and facilities costs. The budgeted O&M costs for 2003 also incorporate over $0.2 million in revenue representing payments from CustomerWorks to BC Gas for the use of human resources services as part of the Shared Services agreement with CustomerWorks. This revenue offsets the O&M cost of services provided by Human Resources.

Human Resources services are delivered to 1,330 employees. A 2001 study by the Conference Board of Canada analyzed human resources cost metrics in industry, indicating the average ratio of human resources staff per 100 employees is 1.8 compared to the Company with 0.26; and the average cost of the human resources function per human resources employee is $119,200 compared to the Company with $102,200.

The value to customers from Human Resources activities and efficiencies lies in the provision of effective leadership and highly skilled and trained staff in the safe operation of the gas delivery system and the support systems behind it. Customers will further benefit from the forecast 2003 Human Resources department expenditures, as human resources services are required to respond to the key business drivers, including: increased employee training requirements due to legislative and regulatory changes in the areas of employee health and safety, environmental management, and trades training; an ageing workforce and changing demographics in the labour market affecting the Company's ability to attract and retain skilled employees; increased employee benefits costs due to changes in provincial medical coverage and legislative requirements affecting registered pension plans involving additional administrative work; and regulatory requirements affecting the governance of pension plans.

c. Historical O&M Expenditures, 1997 - 2002

The following table sets out Human Resources' annual O&M expenditures for the period of 1997–2002.

HR's Annual O&M Expenditures ($ millions)

	1997 Actuals	1998 Actuals	1999 Actuals	2000 Actuals	2001 Actuals	2002 Projected
Total Nominal O&M	**5.9**	**5.7**	**4.8**	**4.8**	**4.8**	**5.1**
Total Real O&M	**6.3**	**6.0**	**5.0**	**4.9**	**4.9**	**5.1**

Note: Real totals in 2002 values.

The projected 2003 O&M requirement of $5.3 million reflects a $0.6 million, or 10.2%, reduction when compared to 1997. This reduction is the result of efficiency gains obtained through a combination of staffing reductions, streamlining administrative functions, and efficiencies in delivery of trades training. Efficiencies in the trades training area were significant during this period when O&M expenditures declined by 34%. The reductions were realized by reducing expenditures for external consultants used for the development of courses; more efficient use of materials; a reduction in travel by instructors; and by reallocating work so that retired instructors were not replaced. Additional efficiencies were gained by reducing the frequency of company required re-certifications of certain skills, such as PE fusion from every year to every two years. These changes resulted in a more efficient delivery of training programs.

With respect to the value gained by customers of other Human Resources activities, important benefits accrued to customers through negotiations between the Company and the IBEW that resulted in a significantly changed collective agreement. This five-year collective agreement was signed in September 2001. Key changes from the previous agreement include:

- The Company and the IBEW agreed to introduce swing shifts without premium payment until 8:00 p.m. Monday to Friday. This allows employees to be more readily available to customers and reduces expenditures previously paid for call-out overtime premiums.
- Company policy provides for some staff to be on stand-by in order to be called out to customer emergencies. This practice provides cost-effective flexibility in staffing on regular work shifts. Stand-by staff coverage for emergency response was enhanced in conjunction with reductions in the premium pay costs associated with that coverage.
- Moving construction crews among mustering points in response to fluctuations in workload means greater ability to respond to customer requirements, without penalties (premium cost to Company).

Over the past five years a number of legislative and regulatory changes affected the cost of administering the Company’s two registered pension plans (The BC Gas Utility Ltd. Pension Plan for IBEW and OPEIU Members and the BC Gas Utility Ltd. Retirement Plan for Management and Exempt Employees). Examples of changes in the *Pension Benefits Standards Act* (PBSA) include:

- Bill 58 Amendments to the PBSA in 1999 - 2000 affecting definitions of spouse, as well as numerous administrative matters;
- PBSA portability of pension changes in 1998;
- PBSA vesting changes in 1997 - 1998; and
- PBSA credited service changes respecting maternity leave (1997).

In addition to the specific costs to the pension plans of the above changes, all of these required human resources staff to ensure Plan Amendments were prepared; passed by pension Trustees; properly filed with the regulatory bodies; costing by Plan actuaries was completed; and beneficiaries notified.

The Company believes there will continue to be changes in pension legislation as there is a trend across Canada to increasing governance with respect to pension plans.

In real dollar terms, human resources has achieved significant efficiency gains since 1997. The cost per customer decreased from $8.90 in 1997 to $6.83 in 2002. This represents a 23.3% decline. Forecast expenditures for 2003 confirm a further decline in real dollar terms by 0.3%.

d. Forecast O&M Expenditures, 2003 - 2007

The 5-year O&M forecast for Human Resources is set out in the table below.

HR's Annual O&M Expenditures ($ millions)

	2002 Projected	2003 Forecast	2004 Forecast	2005 Forecast	2006 Forecast	2007 Forecast
Total Nominal O&M	**5.1**	**5.3**	**5.5**	**5.6**	**5.8**	**6.0**
Total Real O&M	**5.1**	**5.2**	**5.3**	**5.3**	**5.4**	**5.5**

Note: Real totals in 2002 values.

The 2003 O&M forecast for human resources is $5.3 million compared to $5.1 million in 2002. This increase is driven primarily by anticipated costs associated with legal services required for expert labour relations advice and general and labour inflation. Labour relations advice will be required on an on-going basis to ensure consistent collective agreement interpretation and Company response to grievances and arbitrations. The forecast O&M reflect significant changes and needs in human resources activities during the next five years. These changes include:

- increased activities to create a succession planning pool to ensure there are sufficiently knowledgeable people to assume leadership and technical positions as first-line managers and technical experts retire;
- increased focus to manage employee claims due to short-term and long-term disability. This issue also relates in part, to an ageing workforce in which injuries and illnesses tend to increase. More time and dedicated resources will be required to facilitate return-to-work programs for employees who may be partially disabled for health or injury reasons; and
- increased legal costs as the company faces challenges on labour relations and human rights issues due to continual changes and pressure on the workforce to be more productive.

Notwithstanding these pressures, 2003 Human Resources forecasts an increase in O&M costs for general and labour inflation only. Over the next five years, Human Resources O&M cost per customer is forecast to decrease from $6.81 in 2003 to $6.55 in 2007 representing a 3.8% decline in unit costs.

The focus of the Company's workforce now and into the future will be to continue to look for continuous improvement in work processes to provide to the customer a safe, reliable, environmentally responsible and cost-effective gas delivery service. The overall goal of the Human Resources function, therefore, will be to ensure that the workforce of the Company is of a quality and quantity to achieve these Company objectives. This is accomplished by ensuring its hiring practices, labour relations strategies, training and development programs, total compensation programs, and the associated processes and systems to support them, are effective and efficient. During the period 1997 – 2002, significant efficiencies were realized through a combination of staffing reductions, streamlining administrative functions, and efficiencies in the delivery of trades training.

The key cost driver affecting the forecast 2003 O&M expenditures for Human Resources is the level of staffing required to deliver the above services, including: the negotiation, contract administration and interpretation of the Company's collective agreements; the development and delivery of mandatory training to employees and delivery of programs such as leadership and performance management programs; the design and administration of compensation, benefits and pension programs; staffing; and payroll.

The forecast expenditures for Human Resources for 2003 – 2007 reflect no increase to Human Resources FTEs, but only an increase for general and labour inflation. The current staff will need to be re-allocated to support the Company's needs arising from: regulatory requirements for employee training; ageing workforce and the competition for talent; and increased employee benefit costs due to changes in provincial medical coverage.

CONCLUSION

BC Gas has a requirement to operate and maintain its transmission and distribution system in a safe and reliable manner. For BC Gas to meet those requirements, it must make significant O&M expenditures each year. This Application contains BC Gas' 2003 forecast for expenditures, as well as, a forecast for 2004 to 2007. The level of O&M expenditures in the forecast is reasonable and appropriate. This forecast should be accepted as the basis for 2003 rates and as a basis for a multi-year comprehensive PBR Plan.

E. FINANCING, ACCOUNTING AND TAX ISSUES

This section addresses the Company's financing activities and requirements, changes in accounting policies and procedures followed by the Company, deferral accounts and amortization and taxes.

1. FINANCING ACTIVITIES AND REQUIREMENTS

The Company finances its $2.5 billion in invested assets with a mix of debt and equity following the Commission's approved capital structure of 33% common equity and 67% debt. The debt is a combination of long-term and short-term debt issues in the Canadian capital markets.

a. Historical financing activities 1997 – 2002

BC Gas has regularly raised funds in the corporate debt markets, issuing over $900 million in long-term debt from 1997 to date in 2002. All of this issuance took the form of medium term note debentures, with interest rates ranging from 5.10% to 6.95% and with maturities between two years and thirty years. Over the same period, BC Gas Utility Ltd. issued common equity of approximately $185 million, which enabled the Company to maintain a 33% equity component in its capital structure. The proceeds from these issues were used to finance new capital expenditures, to refinance $216.0 million in maturing long-term debt and to replace $150.0 million in preferred shares with debt pursuant to the conditions of the 1998 - 2001 PBR Plan.

b. Change in Financing Policy

The Company has revised its targets for the appropriate mix of short-term borrowings and long-term borrowings supporting rate base. Over the past several years, the Company has targeted a capital structure comprised of 33% common equity, 52% long-term debt, and 15% short-term debt. The revised target capital structure is 33% common equity, 59% long-term debt, and 8% short-term debt supporting rate base.

The major reason for this change is the additional liquidity requirements that have been imposed on the Company due to the large GCRA and RSAM deficit balances that accumulated mainly in 2000 and 2001. Although the GCRA and RSAM balances will be fully recoverable over time, the delayed recovery of these balances creates a short-term financing requirement that, given the potential volatility in gas supply costs, is difficult to predict. Therefore, one impact of the potential volatility in gas costs is the need to have available additional liquidity over and above the liquidity requirements of the past to finance potential increases in the GCRA balance. These needs have led BC Gas to increase its commercial paper program limit from $350 million to $500 million, resulting in increased annual bank fees.

In addition, the collapse of Enron and the difficulties faced by other energy market participants have led to demands by the Company's counterparties for credit provisions in gas purchase agreements that include margin or collateral requirements. These provisions require the Company to provide a letter of credit or cash collateral in certain events, including if the Company's gas purchase commitments exceed set thresholds or if the Company's creditworthiness deteriorates. In order to ensure that the Company can meet these margin or collateral requirements, and provide a reliable supply of natural gas for its customers, the Company needs to have bank credit facilities available to it in excess of the requirements arising from the day-to-day operations of the Company.

Unfortunately, there has also been a reduction in the overall capacity of the Canadian market for backstop credit facilities. Over the past several years, a number of foreign-based banks, notably Japanese banks, have reduced or completely eliminated their operations in Canada. It is also anticipated that changes to Federal government policy will facilitate the consolidation of the largest five or six Canadian banks into a smaller group of as few as two or three. This could further reduce the availability and attractiveness of backstop credit facilities. Backstop credit facilities are an essential part of the Company's liquidity management, as they are required by credit rating agencies to be in place to support the authorized borrowing limit of the Company's commercial paper program. In addition, recent events in California have clearly demonstrated how a sharp increase in liquidity requirements, combined with a loss of confidence by the financial markets, can plunge a regulated utility (in this case, Pacific Gas & Electric Company and Southern California Edison) into financial distress in a short period of time.

The events in California have also highlighted the need to avoid undue reliance on short-term borrowings as a means of financing long-term assets. Accordingly, the Company has revised its target capital structure. Implementing this change will involve the issuance of approximately $150 million in additional long-term debt over and above the requirements that would otherwise be implied by debt maturities and rate base growth. The Company expects to carry out this financing in early 2003, following scheduled debt repayments in the second half of 2002. This financing has been incorporated into the financial projections in the Application. The Company's authorized commercial paper borrowing limit will not necessarily decrease by a corresponding amount, as some of the capacity previously used to finance rate base will be reserved to meet unanticipated working capital requirements, such as increases in the GCRA balance and credit requirements in gas purchase agreements.

This change in financing policy will result in slightly higher interest costs as fixed rate borrowings have historically incurred a higher cost than floating rate borrowings. In order to mitigate the interest cost impact of increasing the proportion of long-term debt in the capital structure, the Company intends to maintain its fixed interest rate and floating interest rate exposure at previous levels (52% of rate base fixed, 15% floating). This can be achieved by issuing floating rate bonds, or through the use of interest rate derivatives. The increased cost associated with the use of these structures is expected to be less than 0.50% per annum. Other Canadian companies facing similar circumstances, including Enbridge Consumers Gas which issued $100 million of floating rate bonds in November 2001, and numerous companies in the United States have used this strategy.

BC Gas will revise its mix of short-term and long-tem borrowings and will issue approximately $150 million of incremental long-term debt and through interest rate swaps or floating rate bonds will mitigate the impact on financing costs. By linking the cost of this incremental $150 million in long-term debt to short-term interest rates, the Company anticipates savings of $2.25 million annually as compared to financing tied to long-term interest rates, based on the interest rate projections discussed below.

c. Financing requirements and forecast interest rates for 2003 - 2007

With the completion of the Southern Crossing Pipeline project, BC Gas anticipates that financing requirements arising from capital expenditures will return to more normal levels. The anticipated LILO transactions with Vernon, Nelson and Prince George also reduce the requirement for new long-term debt issuance by approximately $50 million. New long-term debt issuance in the 2003-2007 period is expected to total $800 million, including the $150 million in 2003 to implement the revised mix of short-term and long-term debt referred to previously.

Short-term interest rates, which have been at historically low levels in 2002, are expected to rise significantly during 2002 and 2003 and return to levels that are more typical of recent history. The Company forecasts a short-term interest rate of 5.0% for 2003, as well as for the 2004-2007 period. In arriving at this forecast, the Company has considered both historical short-term interest rates, and implied forward interest rates in the capital markets. Over the last ten years, the average three-month bankers' acceptance rate has averaged 5.04%. In addition, six-year interest rate swaps currently have a fixed rate of approximately 5.25%, which implies that the financial markets expect three-month bankers' acceptance rates over the next six years to average 5.25%. It should be noted that the Company's all-in cost of short-term borrowing normally exceeds the three-month bankers' acceptance rate by approximately 0.15%. Even though this implies a 5.40% short-term interest rate, a rate of 5.0% has been reflected in the Application. For 2003, a one-year interest rate swap starting on January 1, 2003 would currently have a fixed rate of approximately 4.50%, which implies that the financial markets expect three-month bankers' acceptance rates to average 4.50% during calendar 2003. Given the incremental costs over bankers' acceptance rates referred to previously, the Company believes that a short-term interest rate of 5.0% is reasonable for 2003 on a stand-alone basis.

The Company expects its costs of fixed rate, long-term borrowing to be 7.0% over the 2003-2007 period, which approximates current long-term borrowing costs.

2. ACCOUNTING POLICIES AND PROCEDURES

The accounting policies in the Company are kept in accordance with Generally Accepted Accounting Principles ("GAAP") and the external auditors each year report that the financial statements are prepared in accordance with GAAP.

There are a number of exposure drafts, accounting guidelines and research studies currently underway at the CICA which may have implications for the Company. Below is a summary of the activities in progress. BC Gas is seeking recovery through rates for changes in accounting standards.

a. Rate-regulated Operations

There has been an ongoing research study by the CICA to review financial accounting for rate-regulated enterprises. Although a research study has not as yet been published, one is expected at the end of June 2002. An article in "CA Magazine" has indicated that the research study, if implemented would be controversial. It is expected that their findings will have significant influence on future accounting standards and reporting requirements for rate-regulated enterprises in Canada. For example, one of the proposals currently being reviewed is the Application and adoption of future income tax ("FIT") accounting for rate-regulated utilities. Should this be the case, future tax expense will create an additional charge against earnings. In addition, the large FIT liability required under FIT accounting would increase the Company's Large Corporation Tax (LCT) expense.

b. Special Purpose Entities

In response to concerns arising from the collapse of Enron, the Accounting Standards Board of the CICA and the U.S. Financial Accounting Standards Board (FASB) are developing guidelines that propose the consolidation of special purpose entities (SPE). This means that the synthetic lease in place to finance the Coastal Facilities project would need to be recorded in the Company's balance sheet and no longer be treated as an operating lease. In accordance with BCUC directions, and in order to meet the expectations of credit rating agencies, the Company has maintained over time its allowed capital structure of 33% equity and 67% debt supporting rate base. When the synthetic lease was established, the Company agreed that the Coastal Facilities project could be financed outside of rate base with 100% debt within the synthetic lease, because the debt would not appear on the Company's balance sheet and therefore the debt ratio reported in the Company's financial statements would be preserved. Because the synthetic lease is effectively financed with 100% debt, on-balance sheet accounting for this obligation will result in the Company's debt ratio exceeding the levels presently authorized by the BCUC and expected by credit rating agencies. In order to restore the Company's debt ratio to levels expected by credit rating agencies, the Company will need to issue or retain additional common equity. Unless the Coastal Facilities assets are included in rate base, with an allowed return based on 33% equity and 67% debt, the Company will be penalized by having to maintain common equity that it is not permitted to earn an appropriate return on. If the accounting treatment for the synthetic lease is changed, the Company would request treatment in accordance with BCUC Order Number C-14-98. This Order confirms that "the Company shareholders will be protected from the impact of changes to the current accounting and tax rules" and "if it is not feasible to renew the lease arrangement, the outstanding costs of the Project may be financed as a traditional rate base item". In these circumstances, the Company would expect to collapse the current lease arrangement and would finance the Coastal Facilities assets with a conventional mix of debt and equity, as the cost of debt in the synthetic lease is moderately higher than the cost of debt achievable through the issuance of conventional debt. The proposed guideline is expected to be published in July 2002.

c. Asset Retirement Obligations

In order to harmonize Canadian GAAP with United States GAAP, the CICA has issued an exposure draft on Asset Retirement Obligations (ARO). This exposure draft, if implemented, will require companies to recognize a liability for any retirement obligation at fair value when it is incurred. These obligations can result from existing or enacted law, statute, ordinance, or contract. The amount of the obligation would be set up as a liability and capitalized as an additional cost of the related asset, which would then be depreciated over the asset's remaining useful life. The liability would be adjusted in subsequent periods for interest expense and for any changes in the estimated value of the obligation, with a charge to expense. There is no exemption for rate-regulated enterprises. The proposed effective date is for fiscal years beginning on or after January 1, 2004. Should the proposals for AROs be adopted, the Company would seek to recover such costs in future rates.

3. COMPLIANCE WITH TRANSFER PRICING POLICY AND CODE OF CONDUCT FOR BC GAS UTILITY

With regard to cross-charges to the Non-Regulated Businesses (NRBs), the Company complies with the Transfer Pricing Policy and the Code of Conduct for provision of Company resources and services (documents dated August 1997). Employees keep track of the time they spend on non-utility activities. The salary cost, loaded for benefits and concessions, and an overhead charge for the use of facilities and other resources, and in some cases, an availability and supervisory surcharge is then charged to the NRB and invoiced on a monthly basis. This process is managed through the continuing services contracts between the Company and the following NRBs:

BC Gas Inc.
BCG Services Inc.
BCG International Inc.
ENRG (PFC eFuels Inc.)
Trans Mountain Pipe Line Co. Ltd.
Corridor Pipeline Limited
Huntingdon International Pipeline Corp.
Squamish Gas Co. Ltd.
Sumas International Pipeline Inc.
Inland Pacific Energy Services Ltd.
Centra Gas British Columbia Inc.
Centra Gas Whistler Inc.

Work performed for BC Gas Inc. is categorized as either (1) General and Administration or (2) Non-Utility. The General and Administration activities include preparation of financial statistics, financial reporting, tax reporting, financial planning, investor and shareholder relations and other activities performed on behalf of BC Gas Inc. and benefiting all companies under the BC Gas umbrella. Since the Company represents the largest subsidiary of BC Gas Inc., in previous years, 80% of these charges was allocated back to the Company. This allocation was consistent with the relative proportion of assets, revenues, and earnings of the BC Gas Inc. group of companies. With the growth of BC Gas Inc. through the development of new projects (e.g. Corridor pipeline) and acquisition of other companies (e.g. Centra Gas), this allocation has been reviewed and has been determined to be approximately 70% for 2002 and onwards. This reduced charge-back percentage is reflected in the O&M expenses in this Application.

Non-utility activities performed on behalf of BC Gas Inc. and other NRBs are charged 100% to BC Gas Inc. and to the NRBs respectively. This is managed through monthly timesheets and appropriate charge codes for each NRB. For 2003, it is expected that Company personnel will charge BC Gas Inc. and other NRBs for 33,200 hours of work. This translates to a reduction of $2.2 million in Company O&M expenses and a $0.5 million recovery of overheads. While the amount of charges to the NRBs will vary slightly from year to year, the Application assumes this amount of cross-charges will remain constant at these levels for the 2003 – 2007 period.

The Company has been asked previously to address the charges made by BC Gas Utility officers to BC Gas Inc. and other NRBs. The table below summarizes the percentage of total hours charged out to BC Gas Inc. and its NRB's for 2002 onwards.

Mary Bruce	13%
Randy Jespersen	2%
Ron Jupp	0%
Jan Marston	5%
David Masuhara	4%
John Reid	46%
Steve Richards	19%
Bob Samels	5%
Doug Stout	0%
Milton Woensdregt	42%
David Zerr	0%

4. DEFERRED CHARGES AND AMORTIZATION

This Application seeks Commission approvals respecting deferral accounts and amortization. By way of a general comment the recording of deferred charges and their amortization follow the provisions of the respective BCUC orders approving the various accounts. The Company's requests in this Application pertain to cases where BC Gas does not have specific approval to defer and amortize particular amounts or to cases where deferral has been approved but the amortization period has not yet been set by the Commission. The forecast of deferred charges is found in Section H, Tab 3.

a. Rate Stabilization Adjustment Mechanism ("RSAM")

The RSAM is a mechanism that stabilizes the Company's collection of delivery margin from the Residential and Commercial customer classes (Rates 1, 2, 3 and 23). The RSAM enables the Company to record delivery margin for these customers classes based on the forecast use per customer for each rate class that was used in establishing rates. If weather or other factors result in the customer use varying, an entry is made in the RSAM account that brings the delivery margin back to the approved forecast use per customer level.

The recent experience of high commodity prices has contributed to customer use decreases well beyond the impact of weather leading to large unforecast deficit (i.e. debit) accumulations in the RSAM account, mainly in 2000 and 2001. In the context of these large unforecast balances and uncertainty around customer use rates going forward the Company is seeking treatment for RSAM account balances similar to that for the Gas Cost Reconciliation Account ("GCRA"). Variances from the forecast GCRA balance attract interest at the Company's short-term borrowing rate. The recording of interest on the variance from the forecast GCRA balance was approved by BCUC Order G-98-95. At that time there had been unforecast credit accumulations in the GCRA which, it was asserted by intervenors, provided carrying cost benefits to the Company at no cost. The booking of interest on variances reduces the likelihood of large carrying cost benefits or losses accruing to either the Company or to customers. In the prevailing circumstances for the RSAM, BC Gas considers it reasonable and appropriate to apply the same interest treatment to variances from the forecast RSAM account balance.

b. Property Tax, Income Tax and Government Levies Deferral Account

The Company has in the past had deferral accounts to collect variances in its cost of service arising from property taxes, income taxes and government levies. Changes in the costs in these areas are beyond the Company's control and the timing of such changes often does not fit well with the regulatory process for setting rates. The 1998 – 2001 PBR Plan included deferral accounts for such changes in taxes and government levies. BC Gas is requesting that in 2003 similar treatment be afforded the Company. While the determination of amounts to be deferred for tax and levy changes will follow past practice, BC Gas is requesting a specific approach be established for the manner of refunding or recovering the accumulated balance.

Specifically, BC Gas requests the following:

- that a deferral account be established to collect variances between actual and forecast property taxes and to collect variances in other government taxes, charges and levies, both direct and indirect, including changes in tax laws or accepted assessing practices at federal, provincial, municipal or any other level, from those embedded in the rates approved as a result of this Application. In addition, the Company is being reassessed for BC Corporation Capital Tax for the years from 1995 forward. While these reassessments will be appealed, BC Gas seeks to collect in this account the costs of the appeal process and the amount of any net reassessments owing;
- that accumulated balances in this account be subject to interest at the Company's short-term borrowing rate; and
- that refunding or recovering the accumulated balances (including accumulated interest) occur over a three-year period through a rate rider commencing in the year following.

The rationale for requesting that this be an interest-bearing account is similar to the basis identified for interest on RSAM variances requested above. BC Gas has forecast a zero balance in this account in its schedule of deferred charges for 2003. Interest on accumulated variance from that forecast will ensure that no large benefit or cost accrues to the Company or its customers from the deferred balances.

The reason for requesting that the amount in this account be refunded or recovered through a rate rider stems from the proposal that 2003 form the base year for a multi-year PBR Plan. The use of a rate rider will allow the refund or recovery of the balance in this account during a multi-year PBR Plan. The three-year amortization period follows the BCUC-approved treatment for the RSAM balances. The Commission found in the context of approving the RSAM that a three-year amortization period offered a reasonable blend of timeliness and smoothing of customer rate impacts.

c. Residual Deferred Charge Issues from the 1998 – 2001 PBR Plan

Several deferral accounts approved by BCUC Order No. G-85-97 or subsequent rate-setting orders from the four Annual Reviews or other proceedings held in that period require Commission determination. Most pertain to setting an amortization period where one has not been established previously. A listing of these requests is found in Section H, Tab 3, Pages 5.1 to 5.5. The requested BCUC order approving the deferral is identified in each case.

There is one deferral account set up in the 1998 – 2001 period that merits a more detailed explanation. This is the amount recorded in deferred charges related to the computer software portion of the income tax refund BC Gas received due to a change in tax treatment of Overheads Capitalized. An appropriate adjustment was made to the contributions-in-aid-of-construction software account to reflect the effect of the tax refund from the change in the tax treatment of overheads capitalized. The balance in the deferral account is a credit that BC Gas seeks to amortize over a five-year period. The amortization of this account results in a revenue requirement decrease. The requested five-year period for amortization is based on the proposed depreciation rate of 20% for computer software

5. PROPOSED CHANGES IN ACCOUNTING POLICIES FOR 2004 ONWARDS

As noted in previous Applications, BC Gas has identified the need for changes in depreciation and overhead capitalization. The depreciation rate changes have been reflected in the financial calculations in Tab H in 2004 and proposed changes to the overhead capitalization rates have been reflected in 2005.

a. Depreciation Rate Changes

<u>Overview</u>

BC Gas retained Gannett Fleming Valuation and Rate Consultants Inc. ("Gannett Fleming") of Harrisburg, Pennsylvania to conduct a Depreciation Study of its utility rate base assets. The initial study work was undertaken in 1997 with a preliminary draft report being issued in early 1998. The study was originally done based on gas plant-in-service as of December 31, 1995 and included utility assets in the Lower Mainland, Inland, Columbia and Fort Nelson Service Areas and BC Gas' Corporate Division. In 1999 Gannett Fleming updated the study to take into account gas plant-in-service and accumulated depreciation as of December 31, 1998.

A new study has not been undertaken to update the information. BC Gas considers that the study results continue to be reasonable and Gannett Fleming estimates the rates calculated in the Depreciation Study are reasonable for a period of three to five years (page III-2). BC Gas has internally updated the plant balances in the Depreciation Study and recalculated the revenue requirement impacts of implementing the Study.

Gannett Fleming has estimated the depreciation rates using various statistical methods and informed judgement based on their extensive experience in the natural gas industry. Straight-line depreciation is developed for the assets in a particular class beginning with the original cost, the estimated average and remaining service life characteristics and then accounting for the accumulated depreciation already booked in that class and the applicable net salvage costs.

Overall, the Gannett Fleming study highlights two factors which contribute to the increase in depreciation rates: technological changes affecting information technology capital, particularly computer software, and the impact of abandonment and removal costs, including in the impact of inflation, on Service Lines, Distribution Mains and Meters.

Full Implementation

Full implementation of the recommended depreciation rates would increase the average depreciation rate for the Lower Mainland, Inland and Columbia Service Areas from 2.96% to 3.68%. Depreciation expense in BC Gas' cost of service would increase by $17.2 million. Since depreciation expense is not tax deductible, the Company's revenue requirement would increase by $27.5 million. In terms of rate impact, this constitutes a delivery margin increase of about 5.6% or a revenue increase of about 2.2%.

Past Applications

In 2000, the Gannett Fleming study was reviewed with Commission Staff and a summary of the study was circulated to interested parties. A BC Gas proposal for increases in some depreciation rates was included in the Annual Review of November 2000, but because of large commodity-related rate increases at that time, the proposal was not implemented. In the Revenue Requirement Application filed in 2001 BC Gas sought to implement, effective January 1, 2002, changes in the depreciation rates for Meter, Meter Installations and Regulators, and Computer Software. That Application was later withdrawn.

Application in 2004

BC Gas believes it is now appropriate to implement increases in the accounts mentioned above in 2004. Accordingly, the 2004-2007 depreciation expense in this Application reflects changes to the depreciation rates for Meters, Meter Installations and Regulators, and Computer Software.

Summary of Impact on 2004-2007 Rates

	2004	2005	2006	2007
Depreciation Study Results to be implemented				
- Meters, Installations and Regulators	$1.6	$1.7	$1.8	$2.0
- Computer Software	2.9	2.5	2.1	(0.5)
	4.5	4.2	3.9	1.5
Mitigating factors				
- Amortization of CIAOC - Software tax savings	(1.0)	(0.9)	(0.2)	(0.6)
Depreciation Expense Impact	$3.5	$3.3	$3.7	$0.9
Revenue Requirement Impact	$5.3	$5.0	$5.7	$1.4

Increased Depreciation Expense

The major sources of increases in depreciation expense resulting from the implementation of the recommended changes to Meters, Meter Installations and Regulators, Computer Software and Hardware along with mitigating factors are discussed below.

Account 483-20 Computer Software

The recommended depreciation rate rises from the existing 12.5% to approximately 20%. The expected life for software in the study is five years implying a 20% depreciation rate. The Gannett Fleming study did not include the software costs for larger systems (e.g. SAP financial system). Recognizing that these large systems have a longer life than implied by the 20% rate, Gannett Fleming recommended that the depreciation of software be split into two categories, with existing software and new desktop software attracting the 20% rate and new large infrastructure-type systems attracting the existing 12.5% rate.

Account 478 Meters

Gannett Fleming estimated the average life of meters at 25 years (4%) and the average remaining life of the meter stock in rate base at 16.7 year. BC Gas has been depreciating meters over 33.3 years (3%). The Gannett Fleming Study recommended rate for meters of 4.78% accounts for both the change to a 25-year life and for catching up for the lower accumulated depreciation, accrued at the 3% rate.

Subsequent to the release of the Gannett Fleming Study, BC Gas has determined the average expected life of a meter is 28 years (3.57%). On average a meter is put into service for two 14-year cycles with re-calibration after the first cycle.

BC Gas is basing its request for a change in 2004 on the lower of these two estimates resulting in a 3.57% depreciation rate for Meters.

Account 474 Meter Installations and Regulators

Gannett Fleming recommended the depreciation rate increase from 3% to 3.67%. A significant contributor to the increase in the depreciation rate is the negative net salvage cost of Meter Installations assessed at 25% of the original cost. The Study has indicated that the high rate of negative salvage is attributable to the cost of disconnecting meters and the amount of inflation that has occurred between the time of original installation and the time that abandonment costs are incurred.

BC Gas is requesting the same 3.57% (28 years) depreciation rate for meter installations and regulators as for meters.

<u>Mitigating Factors</u>

Amortization of Contributions in Aid of Construction

The Gannett Fleming Study recommends an increase of depreciation rates for computer software from 12.5% to 20%. The amortization on contributions in aid of construction related to software tax savings is also changed to reflect the recommended rates.

b. Overhead Capitalization

<u>Overview</u>

In response to concerns expressed by the Commission and other interested parties regarding the capitalization of overheads into rate base, BC Gas filed a study and proposal to substantially reduce its capitalized overhead in the 1998-2002 PBR Application. The study titled “Overheads Capitalized Accounting Policy Change” was filed with the BCUC in the 1998-2002 PBR Application, Volume 1, Section F.

The study recommended a capitalization rate of roughly 10% of total O&M. By Order No. G-85-97, the Commission accepted the study and proposal but approved reductions in BC Gas’ overheads capitalization rate to 20% in 1998, 20% in 1999 and 16% in 2000 respectively on total Gross O&M excluding Defined Required Incremental Activities (DRIA). The rate of 16% was also approved for the one-year extension in 2001. It was viewed that any further reduction to capitalized overhead would have resulted in too large a rate impact for customers.

<u>Future Application</u>

To minimize the impact on customers, BC Gas proposes that the 16% overheads capitalization rate be continued through 2004 and the study method of calculating overheads capitalized be implemented in 2005. The study method of calculating overheads results in a capitalization rate of approximately 10% of total O&M excluding DSM expenses, OPEBs, and the capital-related portion of the CustomerWorks charges.

The following table shows the proposed overhead capitalization rates and their impact on the revenue requirement.

Proposed O/H Capitalized	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**
O/H Capitalized %	16%	16%	16%	10%	10%	10%
O/H Capitalized ($mm)	25.5	26.9	28.7	18.2	18.7	19.3
Resulting Revenue Requirement ($mm)				17.4	18.0	18.6

The detail calculations of the proposed overheads capitalized shown above is set out in Section H, Tab 9, Page 2.2.

<u>Summary of the method used to calculate the 2005-2007 Overhead Capitalized.</u>

The study uses an incremental approach to capitalizing overhead that would capitalize only the indirect variable overhead costs. This means that general and administrative costs, which have no or limited relation to the level of capital activity, will not be subject to capitalization and will be treated as period costs.

The table below shows the current organization and the capitalization percentage of each business area. The capitalization percentages are determined by reviewing the activities performed in the department and consulting the responsible manager. These percentages will be reviewed in the annual budgeting cycle and adjusted as necessary to reflect the changes in activities.

Table: Proposed Capitalization Percentages by Business Area

Business Area	Capitalization %	Notes
Distribution Operations	25%	Capitalization % based on review of activities
Network Development & Operations Support	49%	Engineering 100% capitalized; Measurement Technology 70% capitalized; System Planning 100% capitalized; Planning & Project Development based on activity
Gas Supply & Transmission	N/A	
Customer Care & Marketing	N/A	
Finance	5%	5% capitalization rate for Operations Finance based on review of activities
CEO & President	N/A	
Human Resources	N/A	
RESSCL and Legal/Risk Management	10%	Land Services 90% capitalized; Supply Chain & Logistics 40% capitalized.
Information Technology	N/A	

6. INCOME AND OTHER TAXES

a. Income Tax Rates in Application

Income taxes have been calculated using the flow-through method at the corporate tax rate of 37.62% for 2003 and 35.62% for 2004 and future years. The tax calculations used in the Application effectively exclude the federal surtax of 1.12% because of the ability of the Company to apply the surtax to reduce Large Corporations Tax (“LCT”). The corporate tax rates used in the Application are based on the Canada Income Tax Act and the B.C. Income Tax Act legislation.

This information is set out in Section H, Tab 13.

b. Changes in Income Taxes since 1997

As a result of recent jurisprudence, the Canada Customs and Revenue Agency ("CCRA") now accepts the deduction of indirect overheads for income tax purposes. Previously, the CCRA required capitalization of all direct and indirect overheads.

Taxes in this Application are calculated on the basis of the deduction of indirect overheads for income tax purposes.

c. Other Taxes

Large Corporations Tax ("LCT")

The LCT is equal to 0.225% of a corporation's taxable capital employed in Canada in excess of a capital deduction of $10 million. Net taxable capital is calculated based on the actual balances of liabilities and equity accounts (with certain exceptions) at the corporation's year end and is therefore approximately equal to the total assets of the corporation as of that date, as recorded for accounting purposes. Federal surtax paid is applied to reduce LCT as mentioned above.

Details of the LCT are set out in Section H, Tab 13, Page 6 of this Application.

Goods and Services Tax (GST)

BC Gas, as a GST registrant, is entitled to recover virtually all of the GST it pays on its taxable purchases of goods and services, and is required to charge GST on all its taxable supplies. As such, the tax does not represent a net cost to the Company.

Provincial Social Services Tax (PST)

The Province levies this tax on purchases of tangible property and certain services that the Company uses in its operations. Unlike the GST, the PST is not recoverable and therefore represents a net cost to the Company. The PST rate was raised from 7.0% to 7.5% effective February 20, 2002.

d. Tax issues in 2003 - 2007

B.C. Corporation Capital Tax (CCT)

The CCT has been eliminated effective September 2002. However, the Company is undergoing a CCT audit for the years 1995 to the present. The CCT Branch has completed the 1995 audit and has reassessed the Company on a number of issues. Most significantly, the CCT Branch is proposing to exclude Contributions in Aid of Construction as a credit against capital tax base. For 1995, this represents an increase in the capital tax base of $38.3 million, and tax of $115,000 before interest and penalties. Other adjustments bring the total reassessment to $146,000 before interest and penalties.

The Company expects that the CCT Branch will audit all years since 1995 on the same basis in due course. The total potential liability for years 1995 to the present including interest and penalties is roughly $2.2 million. The Company intends to defend its filing position with respect to the various issues; ultimately the disputed matters may have to be decided by the Courts. BC Gas' historical filing position has been a reasonable and defendable one, and as such, customers have benefited from the lower tax liabilities calculated in prior years. BC Gas is seeking recovery through rates for costs incurred in defending its position, as well as for any tax liabilities and related interest and penalties should the matters be decided against the Company (see also page 10 above).

e. Risk of Changes in Tax Laws or Accepted Assessing Practices

At any time, the Company can face changes in tax laws or accepted assessing practices in respect of federal income tax and large corporation tax, provincial income tax and corporate capital tax, provincial sales tax or any other tax that may be imposed. Given the current economic conditions in the Province of B.C., the Government is facing financial pressures that could lead to an increase in taxes or other user fees. BC Gas is seeking recovery through rates for changes in tax laws or accepted assessing practices at federal, provincial, municipal or any other level as noted at page 10 above.

6. PROPERTY TAX REVIEW

The table below summarizes annual property taxes paid and shows that since 1997 these taxes paid increased by $12.4 million (51.0%) or in real (inflation adjusted) terms by $10.6 million (41.0%).

ANNUAL PROPERTY TAX EXPENDITURES ($ MILLIONS)						
Classification	**1997**	**1998**	**1999**	**2000**	**2001**	**2002**
General (LGA[1] – S353 1% of Revenues)		7.1	7.6	7.6	9.0	11.6
General		2.5	2.6	2.6	3.8	4.2
School		11.7	12.1	12.2	14.9	14.9
Other		3.7	3.9	4.1	5.7	6.0
Total Nominal	**24.3**	**25.0**	**26.2**	**26.5**	**33.4**	**36.7**
Total Real (2002 $)	**26.1**	**26.8**	**27.8**	**27.6**	**34.1**	**36.7**

Note: (1) LGA refers to Local Government Act

The increase in property taxes is primarily the result of additional revenues earned within municipalities due to increased gas commodity costs, the completion of Southern Crossing pipeline, a 4% increase in 2001 to legislated rates used to determine the assessment value of transmission pipelines, and additions to distribution plant. In 2001, the value of BC Gas property subject to property taxation was just over $1.0 billion and, as shown in the table above, BC Gas paid $33.4 million in property taxes.

The average tax rate applied to BC Gas properties in 2001 was approximately 3.3%. That is, for every $1,000 increase in assessment value, BC Gas will pay $33 in additional taxes. In general, the utility property class is taxed at a much higher rate than other property classes. Table below provides comparative data on tax burden for other property classes.

COMPARATIVE PROPERTY TAX BURDEN (BASED ON $1,000 OF ASSESSMENT VALUE)		
Tax Category	**2001 Taxes**	(Note: taxes may vary between jurisdictions)
Utility Category	$ 33	
Major Industry	$ 28	
Office / Business	$ 15	
Residential	$ 8	Excludes Homeowner Grants

Property taxes are based on two components. The first is the “assessment or market value” of the real property and the second consists of a variety of tax rates (historically known as mill rates). As a general rule, a single property tax payment in the Province of British Columbia consists of three main amounts:

- General Taxes – are the taxes levied directly by the local government for the provision of services within the municipality. In BC, utility companies are required to pay 1% (1.25% in the City of Vancouver) of revenues earned in place of the general portion of taxes on all improvements that are not buildings and are used solely within a municipality or group of adjoining municipalities for local transmission, or distribution.

- School Taxes – are levied by the Provincial Government and collected on their behalf by the municipality.

- Other Taxes – are generally levied by other taxing authorities that provide some form of service to the municipality. These may include but are not limited to Hospital Taxes, Transit, Regional District, BC Assessment, and the Municipal Finance Authority. In addition, these may represent more specifically targeted taxes within a municipality or rural area and include such items as road, sidewalks, gas-by-tax, 911 service, and street lighting.

These taxes are paid to either a town or municipality for incorporated areas, the British Columbia Minister of Finance for unincorporated areas, and to First Nations who have been granted taxation authority.

The table below summarizes the 2003 forecast Property Tax.

FORECAST PROPERTY TAX EXPENDITURES ($ MILLIONS)

Classification	2003
General (LGA[1] – S353 1% of Revenues)	15.1
General	4.2
School	15.7
Other	6.2
Total	**41.2**

Note: (1) LGA refers to Local Government Act

Property taxes are subject to pressures in several areas related to downloading from senior levels of government to provincial and municipal governments respectively. Currently, BC Gas has only one individual who is responsible for monitoring and managing property tax issues. From the perspective of management, it is prudent to attain additional resources to actively manage and mitigate property tax increases faced by the Company. As such, the 2003 - 2007 forecast includes incremental funding to provide additional resources in support of this area.

In addition, BC Gas is a member of, and actively participates in, a number of associations in an effort to influence and respond to proposed changes in property taxes. The most important of these are the following:

- the Canadian Energy Pipeline Association (CEPA) Property Tax Committee,

- the Canadian Property Tax Association, and

- the Vancouver Board of Trade Local Government & Finance Task Force.

Other activities that are being undertaken include:

- building and maintaining relationships with the 17 area assessment offices within BC Gas' service area, including the head office of the BC Assessment Authority,
- helping to create a unified voice in dealing with municipal taxation issues by establishing working groups involving all utility class taxpayers and some major industrial tax payers,
- developing a strategic model to manage municipal taxation issues from an industry perspective with other utility tax payers, with the intention of managing taxation issues proactively,
- developing valuation models with BC Assessment that will avoid significant future increases in taxation, and
- creating an integrated lands and facilities management system within BC Gas to help better manage the impact of property taxes.

The Company recognizes that there are uncertainties in the level of property taxes going forward. The cost pressures mentioned above could vary in the timing of their occurrence and in the overall amount of the related expense. Since property taxes are imposed by government, the degree of influence and control that can be exercised by BC Gas on these costs is limited. In the Application, BC Gas has set the annual property tax expense at a fixed amount of $41.2 million - this amount represents the forecast of 2003 property taxes based on current taxation practices. BC Gas is requesting deferral account treatment to capture each year variances from the $41.2 million level. The deferral account would capture any positive or negative variances in annual property taxes from the fixed level. It is proposed that any amounts deferred each year would be charged to or refunded to customers through a rate rider based on a three-year amortization period. See the further discussion of this deferral account at page 10 above.

F. TARIFF CHANGES

This section addresses Tariff changes proposed by BC Gas as part of this Application. These changes are divided into three groups: Transportation Service, Housekeeping, and Clarification changes. In addition, a discussion of ongoing business process reviews that may result in the need for potential future Tariff changes is provided at the end of this section.

The Tariff changes proposed in this Application are primarily driven by three factors. First, Tariff revisions are required to reflect certain enhancements to services which respond to the changing expectations and needs of customers. Second, Tariff changes are also required to reflect changes in the business practices of BC Gas that are driven by external changes in the natural gas industry, particularly with regard to Transportation Service. Third, Tariff changes have been proposed to ensure the rights and obligations of BC Gas and its customers are described in a clear and understandable manner.

In the following discussion, the specific proposals are outlined with an explanation regarding the need, along with the proposed Tariff language.

1. TRANSPORTATION SERVICE TARIFF CHANGES

BC Gas is currently working on system improvements to the transportation service scheduling systems that are designed to support self-service web-based nominations and reporting. These system enhancements will be completed later this year. BC Gas intends to file Tariff changes to reflect those improvements once customers have had the opportunity to become familiar with the enhancements. A number of Transportation Service Tariff changes, however, are required prior to that time and are described below.

a. Provision of Daily Consumption Data

At the request of Shipper Agents, BC Gas has increased the frequency of providing inventory and group data on a reasonable efforts basis and BC Gas will continue to make efforts to enhance this service. A Tariff change is proposed, however, for Section 4.1 of the Shipper Agent Agreement to reflect that the data provided on a twice weekly basis is on a “best available” basis, as that data is not billing grade data, and does not replace the need for close contact by the marketer with its customers in determining the daily requirements of the group. The specific Tariff language change is as follows:

“4.1 **Weekly Provision of Data** - Twice a week BC Gas will provide to the Shipper Agent a schedule setting out ~~the~~ BC Gas’ best available data on the daily ~~takes~~ consumption of the Group.”

b. Amendments to Group Membership in Shipper Agent Agreement

It is also proposed that the Shipper Agent Agreement be revised to allow marketers to advise BC Gas in writing of changes to the group without requiring a new, signed Shipper Agent Agreement each time a change affects the group. The current practice has been to require new Shipper Agent Agreements to be executed each November 1 due to the large number of Group member changes that occur effective November 1 each year. The Tariff change proposed here together with BC Gas’ new practice of encouraging Shipper Agents to evergreen Shipper Agent Agreements will reduce the administrative burden on both BC Gas and the Shipper Agent.

The specific changes to Sections 5.1 to 5.3 of the Shipper Agent Agreement that are proposed are to delete those sections and replace them with the following:

“5.1 **Amendments to Group –** Schedule “A” sets out the Shippers who are the members of the Group represented by the Shipper Agent to this agreement. No additions or deletions may be made to the Group without the Shipper Agent providing notice to BC Gas of such additions and deletions through provision to BC Gas of an amended Schedule “A” showing such additions and deletions and the effective dates of such additions and deletions in accordance with Section 5 of this agreement.

5.2 **Deletions from Group** – If the Shipper Agent wishes to cease acting as agent for a Shipper and a Shipper wishes to cease being a member of the Group, upon receipt by BC Gas of not less than 30 days prior written notice from both the Shipper and Shipper Agent and provided that the Shipper Agent has provided to BC Gas an amended Schedule “A” showing the effective date of deletion of the Shipper from the Group, such Shipper shall be deleted from the Group upon the effective date specified in the amended Schedule “A”. A Shipper will be deleted from a Group effective November 1 of a Year if BC Gas receives not less than 30 days prior written notice from either the Shipper or Shipper Agent.

5.3 **Additions to Group** – If the Shipper Agent wishes to add a Shipper to a Group and the Shipper wishes to be added to the Group, and the Shipper has entered into a Transportation Agreement and completed an Appendix "A" – Notice of Appointment of Shipper Agent, and both the Shipper and the Shipper Agent have given to BC Gas not less than 30 days prior written notice of such addition and provided that the Shipper Agent has provided to BC Gas an amended Schedule "A" showing the effective date of the addition of the Shipper to the Group, such Shipper shall be added to the Group upon the effective date specified in Schedule "A"."

c. Direct Billing of Shipper Agents for Group Charges

One service presently provided by BC Gas will be eliminated on November 1, 2002. The Tariff currently contemplates that BC Gas bills individual customers in the marketer's group for Schedule 10 gas and other group level charges such as balancing and backstopping according to an allocation provided by the Shipper Agent. Increasingly, the practice has been for Shipper Agents to pay these charges directly. In addition to reflecting the changing business practices of the Shipper Agents, the elimination of the allocation service will allow BC Gas to be able to bill customers approximately two days earlier than presently possible. The shortening of the billing cycle will improve service to customers and Shipper Agents.

An added benefit to discontinuing marketer allocations is to protect BC Gas from the potential for "credit gaming". BC Gas has, on occasion, had a marketer allocate all of the Group's Schedule 10 purchases to a customer with credit issues just prior to dropping the customer.

The existing Tariff language does not reflect the practice of Shipper Agents assuming the Schedule 10, balancing and backstopping charges rather than allocating them to Customers. BC Gas proposes that the Tariff be changed to eliminate the allocation service and to provide for obtaining payment for Group charges directly from the Shipper Agent. In addition, although most marketers currently pay these charges that are incurred at the Group level to BC Gas, the Company does not have credit arrangements with marketers to cover the marketer's assumption of responsibility for these charges. Credit risk management practices will be implemented with Shipper Agents to reflect the changes in payment practices that have occurred

The specific Tariff changes required for Rate Schedule 22 are as follows. Equivalent changes are required for Rate Schedules 23, 25 and 27.

In the Shipper Agent Agreement, delete Sections 3.8 and 3.9 and replace them with the following new sections:

"3.8 **Shipper Agent Responsibility for Charges** –The Shipper Agent shall be responsible for and will pay directly to, or to the order of, BC Gas in accordance with the applicable Rate Schedules the amounts owing on behalf of the Shippers which are members of its Group on account of the daily Gas consumption of each member of the Group for the following:

(i) the Schedule 10 Gas taken;

(ii) the Schedule 14 Gas taken;

(iii) the Backstopping Gas and the Balancing Gas taken;

(iv) any Unauthorized Overrun Gas taken;

(v) any Replacement Gas incurred; and

(vi) any Positive Imbalance and Negative Imbalance incurred under Rate Schedule 40.

3.9 **Responsibility of Shippers for Unpaid Charges** – If the Shipper Agent fails to pay to, or to the order of, BC Gas any of the charges referred to in Section 3.8 within the time specified in Section 6.2, BC Gas will bill each of the Shippers that are members of the Group on the basis of the best available information. For Balancing Gas BC Gas will bill the Shippers on a basis proportional to the actual consumption of the Shippers during the month. For Backstopping Gas BC Gas will bill the Shippers on a basis proportional to the actual Day-to-Day consumption of the Shippers during the Days when Backstopping Gas was supplied. For Unauthorized Overrun Gas BC Gas will bill the Shippers on the basis of the applicable Standard Priority Schedule provided by the Shipper Agent pursuant to Section 3.4. For Schedule 10 Gas and Schedule 14 Gas BC Gas will bill the Customers of BC Gas which are members of the Group on the basis of the best available information. For Replacement Gas BC Gas will bill Non-Bypass Shippers in the Group on a basis proportional to actual Day-to-Day takes of the Non-Bypass Shippers during the Day for which the Peaking Gas Quantities were not returned. For Positive Imbalances and Negative Imbalances for West to East SCP Transportation Service BC Gas will bill Non-Bypass Shippers in the Group on a basis proportional to the Peak Day Demand of the Non-Bypass Shippers. If further information becomes available, BC Gas will adjust the billings on the basis of the further information."

In the Shipper Agent Agreement, insert the following new section between Section 5 and Section 6 and renumber Sections 6 through 12 accordingly:

"**6 Statements and Payments**

6.1 **Statements to be Provided** - BC Gas will, on or about the 15th day of each month, deliver to the Shipper Agent a statement for the preceding month showing the aggregate Gas quantities delivered to the members of the Group for each of the Shipper Agent's Groups, the applicable charges for which the Shipper Agent is responsible as per Section 3.8 and the amount due. If the Shipper is a member of a Group then the statement and the calculation of the amount due from the Shipper will be based on information supplied by the Shipper Agent, or based on other information available to BC Gas, as set out in the Shipper Agent Agreement. Any errors in any statement will be promptly reported to the other party as provided hereunder, and statements will be final and binding unless questioned within one year after the date of the statement.

6.2 **Payment and Interest** - Payment for the full amount of the statement, including federal, provincial and municipal taxes or fees applicable thereon, will be made to, or to the order of, BC Gas at its Surrey, British Columbia office, or such other place in Canada as it will designate, on or before the 1st business day after the 10th calendar day following the billing date. If the Shipper Agent or Shipper fails or neglects to make any payment required under this Shipper Agent Agreement, or any portion thereof, to or to the order of BC Gas when due, interest on the outstanding amount will accrue, at the rate of interest declared by the chartered bank in Canada principally used by BC Gas, for loans in

Canadian dollars to its most creditworthy commercial borrowers payable on demand and commonly referred to as its "prime rate", plus:

(a) 2% from the date when such payment was due for the first 30 days that such payment remains unpaid and 5% thereafter until the same is paid where the Shipper Agent or Shipper has not, during the immediately preceding 6 month period, failed to make any payment when due hereunder; or

(b) 5% from the date when such payment was due to and including the date the same is paid where the Shipper Agent or Shipper has, during the immediately preceding 6 month period, failed to make any payment when due hereunder."

In Appendix A of the Transportation Agreement, the Notice of Appointment of Shipper Agent, BC Gas proposes items 6 and 7 be deleted and replaced with the following:

"6. Shipper and Shipper Agent acknowledge that BC Gas will bill the Shipper Agent on the bases set out in Section 3.8 of the standard form Shipper Agent Agreement of BC Gas, and if necessary, will bill the Shipper directly on the bases set out in Section 3.9 of the standard form Shipper Agent Agreement of BC Gas.

7. Shipper and Shipper Agent agree to pay BC Gas as billed. Any disputes between the Shipper and the Shipper Agent as to their respective liability for the amounts billed by BC Gas shall be resolved as between the Shipper and the Shipper Agent and shall not constitute a basis for non-payment to BC Gas of the amounts billed."

In Rate Schedule 22, it is proposed that the Section 19.3 be revised as indicated. Changes to the equivalent sections of Rate Schedules 23, 25 and 27 would also be made.

"19.3 **Principal Obligant** – If the Shipper is a member of a Group, the ~~Shipper's~~ obligations <u>of each of the Shipper Agent (acting for and on behalf of the Shippers that are members of the Group) and the Shipper (in the event of the failure of the Shipper Agent to make such payments)</u> to pay <u>to, or to the order of, BC Gas</u> the charges for Backstopping Gas, Balancing Gas, unauthorized overruns and Demand Surcharges set out in the Table of Charges, are ~~that~~

those of principal obligant and not of surety, and are independent of the respective obligations of the Shipper Agent and the Shipper towards each other pursuant to the Shipper Agent Agreement."

d. Notice Period for Switching Between Rate Schedules

BC Gas is also proposing to change the notice periods for customers switching between various sales and transportation rate schedules. For most rate schedules, BC Gas requires "not less than 2 months notice prior to the end of the Contract Year then in effect", to switch between rates. Customers excepted are those moving from an interruptible to firm service, which requires 12 months notice to ensure facilities are adequate for the change. However, there are two Rate Schedules that do not follow the 2-month notice period - Rate Schedules 22 and 27. Rate Schedule 22 requires 6 months notice and Rate Schedule 27 requires 10 days notice to move to any other interruptible Rate Schedule. BC Gas proposes that customers moving from either Rate Schedule 22 or 27 to any other interruptible Rate Schedule require a 2-month notice period to be consistent with the other Rate Schedules. This standardized approach will ensure non-discriminatory treatment of customers switching between firm to firm, interruptible to interruptible, and firm to interruptible rate types. The 2-month notice period is also consistent with the business model proposed for commodity unbundling.

BC Gas believes that this change will have a positive impact on Customers. By aligning the required notice periods to 2 months, each rate class will have an equal opportunity to assess the option of moving to a BC Gas bundled sales rate to that of a third party supplier. More specifically, Rate 22 customers will experience a 4-month reduction in the notice required to move to other interruptible rates, whereas Rate 27 customers will be required to provide 50 days more.

Third party suppliers will benefit from having a consistent time frame to market their services regardless of customer rate class. More specifically, marketers will have an additional 4 months to capture large industrial customers who wish to move to an interruptible bundled sales rate.

From an operations and administrative process perspective, BC Gas will benefit from increased efficiency in the process for effecting customer rate switches, as all administrative process changes will follow the 2-month time frame.

The specific Tariff changes requested with regard to notice period are as follows.

For Rate Schedule 22, in Section 11.2:

> **"**11.2 **Automatic Renewal** - Except as specified in the Transportation Agreement, the term of the Transportation Agreement will continue from year to year after the expiry of the initial term unless cancelled by either BC Gas or the Shipper, subject to section 3.3 (Warning if Switching from Interruptible to Firm Transportation Service or Sales) upon not less than ~~6~~ 2 months notice prior to the end of the Contract Year then in effect."

For Rate Schedule 27, in Section 10.2:

> "10.2 **Automatic Renewal** - Except as specified in the Transportation Agreement, the term of the Transportation Agreement will continue from year to year after the expiry of the initial term unless cancelled by either BC Gas or the Shipper, subject to section 3.3 (Warning if Switching from Interruptible to Firm Transportation Service or Sales), upon not less than ~~10 days~~ 2 months notice prior to the end of the Contract Year then in effect."

2. HOUSEKEEPING CHANGES

As part of this Application, BC Gas also seeks to make a number of housekeeping changes. Several irregularities in the Tariff have been identified that should be addressed. These changes clarify the intent of the Tariff without changing the services provided or the quality of services or rights and obligations of BC Gas or its customers.

BC Gas requests the following housekeeping changes be made to the Tariff.

a. Definition of "Day"

The BC Gas "Day" currently operates from 7:00 am to 7:00 am Pacific Standard Time ("PST") (8:00 am to 8:00 am Mountain Standard Time) and was established on April 1, 1998. Operationally, BC Gas' Measurement Services Group reprogrammed all gas meters at this time. This operational change was made as allowed for in Definition 1.2 of the Industrial and Transportation Rate Schedules. However, the Rate Schedules were never amended to reflect the change in the definition of Day. Although Definition 1.2 of the various Rate Schedules technically accommodates this operational change, the change in Day is not apparent to customers unless the customer is also familiar with the upstream pipelines' business practices and understands the implication of Definition 1.2. In conjunction with this change, the definitions of Month, Day and Year should also be changed to start at 7:00 am PST. The Commencement and Termination, or Expiry, dates of Transportation Agreements and Shipper Agent Agreements will also be changed accordingly.

b. "Local Time" Definition

With the change of the definition of Day the concept of Local Time is no longer required (i.e. 7:00 am Pacific Standard Time is the same as 8:00 am Mountain Standard Time). It is proposed that all references to Local Time in the Tariff be removed and replaced with the appropriate Pacific Standard Time (or Pacific Clock Time, in the case of nomination deadlines) reference.

The following are the Tariff changes that are proposed for Sections 1 (g), 1 (s), 8.2, 11.1 and 18.2 of Rate Schedule 22 to incorporate the changes to the definition of Day and deletion of the Local Time definition. Similar wording changes are required in the equivalent sections of Rate Schedules 4, 6, 7, 23, 25 and 27.

"1. Definitions

(g) **Day** - means, subject to section 1.2 (Change in Definition of "Day"), any period of twenty-four consecutive hours beginning and ending at ~~8~~7:00 a.m. ~~Local~~ Pacific Standard Time.

~~(q) **Local Time** - means Pacific Standard Time for the Inland and Lower Mainland service areas and Mountain Standard Time for the Columbia service area or daylight savings time as the case may be.~~

(s) **Month** - means, subject to any changes from time to time required by BC Gas, the period beginning at ~~8~~7:00 a.m. ~~Local~~ Pacific Standard Time on the first day of the calendar month and ending at ~~8~~7:00 a.m. ~~Local~~ Pacific Standard Time on the first day of the next succeeding calendar month.

(u) **Pacific Clock Time** – means Pacific Standard Time or Daylight Savings Time as it applies in Surrey, British Columbia."

"8.2 **Requested Quantity** - The Shipper will provide to BC Gas by fax or other method approved by BC Gas, prior to 7:30 a.m. ~~Local~~ Pacific Clock Time on each Day (or such other time as may be specified from time to time by BC Gas) such information as may be requested by BC Gas, which will include, but is not limited to, the Shipper's Requested Quantity for the Day commencing in approximately 24 hours. If the Shipper does not notify BC Gas in accordance with the foregoing, then the Shipper's Requested Quantity for the Day commencing in approximately 24 hours will be deemed to be the Shipper's Requested Quantity, adjusted as set out in section 8.3 (Adjustment of Requested Quantity), for the Day just commencing. The Shipper's Requested Quantity each Day will equal the Shipper's best estimate of the quantity of Gas the Shipper will actually consume on such Day."

"11.1 **Term** - The initial term of the Transportation Agreement will begin on the Commencement Date and will expire at ~~8~~7:00 a.m. ~~Local~~ Pacific Standard Time on the November 1st next following, provided that if the foregoing results in an initial term of less than one year, then the initial term will instead expire at the end of one further Contract Year."

"18.2 **Specific Notices** - Notwithstanding section 18.1 (Notice), notices with respect to Force Majeure will be sufficient if

(a) given by BC Gas in writing by fax, or orally in person, or by telephone (to be confirmed in writing) to the person or persons designated from time to time by the Shipper as authorized to receive such notices, or

(b) given by the Shipper by telephone (to be confirmed by fax) in the following manner

To claim Force Majeure..."Please be advised that (name of company and location of plant) has (reason for claiming Force Majeure as provided in section 20) and hereby claims suspension by reason of Force Majeure in accordance with the terms of Rate Schedule 22 effective ~~8~~7 a.m. ~~Local~~ Pacific Standard Time (date

Force Majeure suspension to become effective, but not to be retroactive)."

To terminate Force Majeure..."Please be advised that (name of company and location of plant) requests a return to normal natural gas service in accordance with Rate Schedule 22 and the Transportation Agreement effective ~~8~~7 a.m. ~~Local~~ Pacific Standard Time (date Force Majeure suspension to end, but not to be retroactive) whereby the suspension by reason of Force Majeure currently in force will be terminated.""

c. "Daily Demand" Definition

BC Gas believes that the definitions of Daily Demand in Rate Schedules 5 and 25 and Peak Day Demand in Rate Schedule 23 should be modified to make it clear that the intent is to base the calculation on the highest average daily consumption. In addition, the reference to Note 3 in Section 10.4 of Rate Schedule 25 is incorrect and should be Note 2.

The proposed Tariff changes are as follows.

In the Note 2 of the Table of Charges for Rate Schedules 5 and 25 should be:

"Daily Demand is equal to 1.25 multiplied by the greater of

(a) the Customer's ~~average daily use of gas for the month of greatest use~~ highest average daily consumption of any month during the winter period (November 1 to March 31), or

(b) one half of the Customer's ~~average daily use of gas for the month of greatest use~~ highest average daily consumption of any month during the summer period (April 1 to October 31)~~,~~ ~~multiplied by 0.5~~.

The calculation of Daily Demand will be based on the Customer's actual gas use during the preceding Contract Year."

Section 10.4 of Rate Schedule 23 should be:

"10.4 **Peak Day Demand –** For purposes of determining the Peaking Gas Quantity available to a Non-Bypass Shipper on a Day, the Peak Day

Demand of a Rate Schedule 23 Shipper is equal to 1.25 times the Shipper's ~~average daily consumption of Gas during the Month of that Shipper's greatest consumption~~ highest average daily consumption of any month in the winter period from November through March of the preceding Contract Year. In instances respecting which it is agreed by BC Gas and Shipper that a Shipper's Gas consumption during the preceding Contract Year is not indicative of prospective consumption, BC Gas will set the Peak Day Demand of that Shipper after consultation with that Shipper."

Section 10.4 of Rate Schedule 25 should be:

"10.4 **Peak Day Demand –** For purposes of determining the Peaking Gas Quantity available to a Non-Bypass Shipper on a Day, the Peak Day Demand of a Rate Schedule 25 Shipper is equal to Daily Demand as defined in Note ~~3~~2 of the Table of Charges. In instances respecting which it is agreed by BC Gas and Shipper that a Shipper's Gas consumption during the preceding Contract Year is not indicative of prospective consumption, BC Gas will set the Peak Day Demand of that Shipper after consultation with that Shipper."

d. Updated BC Gas Contact Information

The BC Gas telephone contact numbers and address set out in the Notice Section of each of the industrial and transportation Rate Schedules need to be updated to account for the relocation of the BC Gas Utility staff to the Surrey Operations Centre.

As an example of the required change, Section 18.1 of Rate Schedule 22 should be amended as follows:

"18.1 **Notice** - Any notice, request, statement or bill that is required to be given or that may be given under this Rate Schedule or under the Transportation Agreement will, unless otherwise specified, be in writing and will be considered as fully delivered when mailed, personally delivered or sent by fax to the other in accordance with the following:

if to BC Gas	BC GAS UTILITY LTD.
MAILING ADDRESS:	~~1111 West Georgia Street~~ 16705 Fraser Highway ~~Vancouver~~ Surrey, B.C. ~~V6E 4M4~~ V3S 2X7
NOMINATIONS AND FORCE MAJEURE:	Attention: ~~Transportation Coordinators~~ Marketing Services Representative Telephone: (604) ~~443-6950~~ 592-7788 Fax: (604) ~~443-6952~~ 648-8751 or (403) 206-7293
BILLING AND PAYMENT:	Attention: ~~Manager, Customer Administration~~ Supervisor, CustomerWorks Telephone: (604) ~~443-6509~~ 592-7816 Fax: (604) ~~443-6588~~ 592-7620
CUSTOMER RELATIONS	Attention: ~~Manager~~ Business Leader, Transportation and ~~Industrial~~ Marketing Services Telephone: (604) ~~443-6610~~ 592-7866 Fax: (604) ~~443-6770~~ 592-7894
LEGAL AND OTHER:	Attention: Vice President. ~~Legal,~~ Regulatory, Environment & Safety, Supply Chain & Logistics Telephone: (604) ~~443-6607~~592-7644 Fax: (604) ~~443-6904~~592-7890

if to the Shipper, then as set out in the Transportation Agreement. If to the Shipper Agent, then as set out in the Shipper Agent Agreement.”

e. "Sumas Daily Price" Definition

The definition of Sumas Daily Price as it appears in various Transportation Service Rate Schedules should be modified to account for the fact that the practice for determining the index over weekend and holiday periods has changed. The definition that was approved in the recent Rate Schedule 10 and Rate Schedule 14 application will be adopted.

The specific Tariff wording change is as follows for Note 1 of the Table of Charges of Rate Schedule 22. The same change should be made to the "Sumas Daily Price" definition in Rate Schedules 22A, 23, 25, 27 and 40 and to the definitions of "Kingsgate Daily Price" and "Station 2 Daily Price" in Rate Schedule 40.

> **"Sumas Daily Price** – means the "NW Sumas" Daily Midpoint Price as set out in Gas Daily's Daily Price Survey for ~~gas~~ Gas delivered to Northwest Pipeline Corporation at Sumas, converted to Canadian dollars using the noon exchange rate as quoted by the Bank of Canada one business day prior to Gas flow date, for each Day. ~~For each Day during weekends or holidays and/or other periods during which the Gas Daily may not be published, the NW Sumas Daily Midpoint Price will be deemed to be the average of the prices quoted in Gas Daily on the Day immediately before and after the period for which the Daily Gas was not published.~~ Energy units are converted from MMBtu to Gigajoule by application of a conversion factor equal to 1.055056 Gigajoule per MMBtu."

3. TARIFF CLARIFICATION CHANGES

There are areas of the current Tariff where BC Gas believes that the language needs to be clarified in order to ensure that the rights and obligations of BC Gas and its customers are clear. Based on experience, BC Gas has identified a number of areas where the intent of a clause is not clearly conveyed in the Tariff language. This lack of clarity has in some cases led to internal questions regarding the proper application of business rules. In other cases this has resulted in customers questioning, or undertaking litigation related to a particular business practice. BC Gas believes it will be helpful to all parties to remove these ambiguities prior to entering into a revenue requirement period.

BC Gas proposes that the following clarification changes be made:

a. Recovery of Meter Protection Costs

BC Gas believes that the Tariff provisions in Section 24.4 of the General Terms and Conditions were intended to allow BC Gas to recover the full cost of the provision of meter protection, and updating and altering service lines. BC Gas proposes that the following language be added to the end of Section 24.4 of the General Terms and Conditions,

> "<u>For greater certainty and without limiting the generality of the foregoing, the Customer is responsible for all expense, risk and liability arising from any measures required to be taken by BC Gas in order to ensure that the Meter Sets or related equipment on the Customer's Premises are adequately protected, as well as any updates or alterations to the Service running line(s) on the Customer's Premises necessitated by changes to the grading or elevation of the Customer's Premises or obstructions placed on such line(s).</u>"

b. Re-activation Cost Recovery

BC Gas proposes revisions to Section 5 of the General Terms and Conditions to clarify the intent to recover the costs associated with re-activation of service where the service applicant is requesting re-activation after being de-activated. BC Gas believes that the fee should recover the cost of de-activation where the applicant is the same party that was de-activated.

Section 5.4 (b) (i) should be revised by adding the wording indicated as follows:

"5.4 **Reactivation Charges** - If

(a) Service is terminated

(i) at the request of a Customer, or

(ii) for any of the reasons described in Section 23 (Discontinuance of Service and Refusal of Service), or

(iii) to permit Customers to make alterations to their Premises, and

(b) the same Customer or the spouse, employee, contractor, agent or partner of the same Customer requests reactivation of Service to the Premises within one Year,

the applicant for reactivation must pay the greater of

(i) the costs BC Gas incurs in de-activating and re-activating the Service, or

(ii) the sum of the minimum charges set out in the applicable Rate Schedule which would have been paid by the Customer between the time of termination and the time of reactivation of Service."

c. Force Majeure Obligations

BC Gas believes that it is not the intent of the Force Majeure sections in the various Rate Schedules to relieve Customers of the obligation to continue to pay the Basic and Demand Charges during a Force Majeure event. In order to state this obligation more clearly, BC Gas proposes additional language in the respective Force Majeure section of Rate Schedules 4, 5, 6, 7, 22, 23, 25 and 27.

As an example of the nature of the additional clarifying language, in Section 13.6 of Rate Schedule 5, BC Gas proposes that the section be amended as follows,

"13.6 **No Exemption for Payments –** Notwithstanding any of the provisions of this section 13, Force Majeure will not relieve or release either party from its obligations to make payments to the other in respect of any amounts then accrued and owing under this Rate Schedule and Service Agreement, and Force Majeure will not relieve or release the Customer from its obligation to make payments for any Basic Charge and Demand Charge specified in the Table of Charges for the shorter of the period of Force Majeure and the balance of the term of the Customer's Service Agreement."

d. Telephone Line Requirements for Automated Meter Reading ("AMR")

In most cases where AMR is installed to support the provisions of the applicable industrial or transportation Rate Schedules, BC Gas is able to utilize the Customer's communication lines after regular business hours to collect the measurement data. In some cases access to existing communication lines is not adequate either because the lines are unavailable after regular business hours, or they are not located in a way that easily facilitates the collection of measurement data. In these cases, BC Gas requires customers to install a separate telephone line for AMR requirements. BC Gas proposes the addition of clarifying language in the “Facilities and Equipment” Clause of the “Measuring Equipment” Section of Rate Schedules 22, 23, 25, 27, 5 and 7.

For example, in Rate Schedule 22, BC Gas proposes that Section 14.1 be reworded by adding the language indicated as follows,

> “14.1 **Facilities and Equipment** - BC Gas will, at the cost to the Shipper, install, maintain and operate at the Delivery Point such metering and communications facilities and equipment as BC Gas determines are necessary or desirable for measuring the quantity of Gas delivered pursuant to this Rate Schedule to the Shipper and the Shipper will permit BC Gas, without cost to BC Gas, to use the Shipper's communications lines and power for the purpose of installing, maintaining and operating the measuring equipment of BC Gas.”

4. PROSPECTIVE TARIFF CHANGES

In addition to the changes proposed in this Application, BC Gas anticipates future changes may be required to reflect the outcomes of the ongoing process review initiatives described in this Application in the section dealing with O&M. For example, both the review of all of the business processes involved from the time the meter is read through production and mailing of a customer’s bill to processing payments and bad debt management and the review of the process and systems utilized to provide Transportation Service to Industrial and Large Commercial customers will likely require Tariff changes. BC Gas is also working on system improvements to the transportation service scheduling systems and back-office support processes and systems to support web-based nominations and reporting. In addition, the Network Development & Operations Support Department is engaged in a review of the business processes used to attach new customers to the system through the installation of new mains and services. As BC Gas reviews these processes, it is finding that additional flexibility in the Tariff would allow BC Gas to better respond to customer’s needs and the dynamic nature of the business. Although these initiatives are not completed there have been several process changes identified in area of transportation service provision that will result in an overall increase in the quality of service provision. In order to provide these services, changes will be required to the Tariff either later this year or in 2003.

In addition to these potential revisions, process changes driven by the replacement of BC Gas’ billing system will also affect commercial and industrial customers, and marketers and will need to be reflected in the Tariff. Large commercial and industrial customers and gas marketers are presently billed using a manual process. Effective November 1, 2002, these customers will be billed using the Energy Customer Information System provided by CustomerWorks as part of the customer care outsourcing agreement. Customers and marketers will then be able to access their billing status via the Internet. Marketers will be given access to the consumption data of individual members of their group through a web-based system.

Automation, self-service, and web-access will permit customers and marketers to manage their business with BC Gas with reliability around the clock from anywhere in the world. To achieve these benefits, customers and marketers may require improved Internet access and training in the self-service features imbedded in web-access and the automation of the nomination process. The use of telephones and faxes to carry out the pipeline business will be eliminated once Shippers have had the opportunity to transition to the web-based nominating system. As new automated processes are introduced, additional areas for improvement may be identified over time.

The specific process changes and tariff amendments necessary to reflect those changes are currently being defined. Once these reviews have been completed, BC Gas will file a separate Application with the BCUC to make further Tariff changes as they are required.

5. SUMMARY

BC Gas believes these proposed and prospective Tariff revisions will result in an overall improvement in the quality of service provision and result in greater clarity in the rights and obligations of BC Gas and its customers.

G. MULTI-YEAR COMPREHENSIVE PBR

A key element in bringing value to customers of a public utility is the mode of regulation under which the utility operates. Cost of service (rate base, rate of return) regulation is the traditional method by which the rates of public utilities such as BC Gas have been established. This method of regulation involves the periodic review of the utility's costs through a formal hearing process with rates being determined almost exclusively by reference to the costs of the utility.

While traditional cost of service regulation has allowed customers to have confidence that their rates were "cost-based", that method of regulation does not necessarily lead to the lowest long-term rates for customers of regulated public utilities.

For much of the period since BC Gas and its predecessor companies commenced natural gas service, British Columbia was characterized as having relatively high levels of customer and load growth. Throughout most of that period natural gas has enjoyed a competitive advantage in comparison to the price of alternative energy sources.

BC Gas has recently been experiencing, and is forecasting, significantly lower rates of customer growth. In addition, the consumption of natural gas per account in the residential and commercial sectors has declined. During the recent period of high gas commodity prices, the difference between the retail price of electricity in the BC Gas service area and the delivered price of natural gas narrowed considerably.

In this environment, opportunities for BC Gas reducing costs through economies of scale have dramatically diminished and therefore the need to consider more comprehensive regulatory models is increased. Since 1994 the regulatory model used to set the rates of BC Gas has evolved. BC Gas believes a further expansion of the regulatory mode will provide further opportunities for alignment with its customers.

The Delivery Rate Setting Mechanism ("DRSM") discussed in this section is a more comprehensive ratemaking methodology that BC Gas believes will provide customers with increased benefits and will incent the Company to introduce efficiencies and minimize capital expenditures; all of which is in the long-term interests of customers.

In many jurisdictions, the regulatory framework for utilities has been moving towards an incentive-based mode. B.C. has been leader in Canada in this area. In the process leading to the settlements that helped establish past PBR plans, parties have participated in the exchange of information, commentary, workshops, analyses, negotiations and settlement discussions. The processes culminated in agreements containing elements focusing on incentives to enhance utility performance, as well as ongoing annual reviews to monitor results in a Commission sponsored process.

In British Columbia, the Commission has initiated or endorsed changes to the regulation environment for utilities under its jurisdiction. A sample of these includes:

- facilitating the first direct purchase of natural gas to industrial customers through transportation tariffs in the Inland Natural Gas system (a predecessor company to BC Gas);
- facilitating bypass tariffs for industrials;
- facilitating performance based regulatory plans;
- instituting the first generic ROE automatic adjustment mechanism; and
- instituting alternative dispute resolution mechanisms for rate cases, both revenue requirement and rate design.

1. BC GAS PBR HISTORY

BC Gas has operated under PBR for many years. As experience has been gained, the structure of these plans has evolved. The PBR settlements approved by the Commission for BC Gas have moved the Company and customers into closer alignment of interests and have encouraged the attainment of efficiencies.

Prior to the 1998 – 2001 PBR Plan BC Gas had two-year revenue requirement applications for 1994/95 and 1996/97. These were both effectively forward test year applications with a limited set of predetermined adjustment factors in the second year of both two-year periods. The formula-based approach to setting O&M expenses was first adopted in the 1994/95 settlement and refined in the 1996/97 settlement. The generic approach to establishing the allowed return on equity was established by the Commission in 1994 and was used for the setting of rates in each year of these two applications. While these plans represented a modest evolution away from traditional cost of service regulation, their relatively short duration hindered the seeking of significant efficiencies beyond those embedded in the O&M formula because of the likelihood of having the efficiencies rebased before achieving economic payback.

In 1997 the Commission approved a PBR Plan for BC Gas that was a significant departure from cost of service regulation. That Plan was for the three years from 1998 to 2000. By agreement of stakeholders and the Company, and as approved by the BCUC, it was extended to include 2001. During the period since 1997 the Company has undertaken initiatives to meet and exceed productivity targets in the PBR Plan without deterioration in the quality of service to customers. These initiatives led to the significant reduction of the Company's workforce and the achievement of an operating cost per customer that places the Company amongst the lowest of comparable Canadian LDCs.

Although the Company achieved a high level of performance in the area that was the focus of the 1998 - 2001 PBR Plan, namely O&M expenses, the delivery rates of the Company increased during the term of the PBR Plan. The primary driver of this increase was the necessary and required investment in capital to provide safe, reliable and efficient service to customer.

The regulatory model that was negotiated in 1997 was developed in an era of considerable customer growth and gas prices that were lower than the prices of other energy sources. The most significant incentive that the PBR Plan provided to the Company was that of reducing O&M costs. The O&M productivity targets in the PBR Plan were set at a high level, given an assumption of continued high customer growth. The Company was able to meet the productivity targets, but only by investing approximately $12.4 million in a restructuring initiative. The multi-year term of the 1998 - 2001 PBR Plan provided the Company with an opportunity to recoup the costs of restructuring and thereby obtain an economic payback.

The Company's experience under the 1998 - 2001 PBR Plan demonstrates that sizeable and on-going business changes will be needed in the Company to achieve future gains in efficiency. These changes will undoubtedly require significant investment, and accordingly need a sufficiently long period of time to achieve an economic payback. For the 1998-2001 PBR Plan, the cost to the Company of the $12.4 million restructuring cost was reduced to $9.4 million through a $3 million restructuring contribution from customers that offset part of the restructuring expenditures. Even with the $3 million contribution from customers' rates, the Company required four years to recoup its restructuring expenditures.

The PBR plans that have been in place for BC Gas have provided the Company with incentives to achieve greater efficiency in its operations and in doing so the Company has in large measure taken advantage of the "low-hanging fruit". Future efficiencies require more complex, aggressive and costly changes to business operations. The Company's ability to achieve economic payback demands that the regulatory mode to be more comprehensive to include a combination of items such as longer term, a larger share of savings, and a larger contribution by customers to restructuring costs.

Under the 1998 - 2001 PBR Plan, the extent to which the Company could recover restructuring costs was dampened by the absence of an adequate multi-year payback mechanism in the areas of capital and new revenues. These areas were rebased each year of the Plan; which minimized the opportunity for savings in capital or an increase in revenues to be used for the recovery of restructuring expenditures. The 1998 - 2001 Plan was initially limited to three years, and did not include a phase-out mechanism that provided for the recovery of efficiency-related expenditures made in the later years of the Plan. Further, the 50:50 earnings sharing mechanism reduced the Company's opportunity for payback for initiatives by half. With limited opportunity for an economic payback of costs incurred to produce efficiencies, economic justification of measures to produce increased efficiency was also limited.

2. OPPORTUNITY TO EVOLVE PBR

The continued pursuit of efficiency gains requires an increasingly more comprehensive regulatory model. The model should integrate all elements of the utility business, including operating and maintenance expenses, capital expenditures and revenues. A focus on integrating all elements of the Company's business in a balanced fashion to deliver value to customers is needed. The methodology discussed in this section does not focus only on O&M, but rather provides for incentives to achieve efficiencies in capital expenditures and to enhance the generation of revenues. The enhancement of the PBR methodology to include these elements creates greater rate certainty and predictability for customers, but also creates greater risk for BC Gas. BC Gas is prepared to assume the greater risk under an appropriately constructed PBR methodology.

BC Gas believes a clear opportunity exists at this time to advance the mode of regulation in British Columbia. The Commission and its Staff have taken a role in advancing and enhancing the mode of regulation in B.C. The recent Interim Report of the Task Force on Energy Policy has reinforced the Commission's actions in this evolution and has recommended that the Commission provide leadership on:

- results oriented regulation; and
- performance-based rate setting through negotiated settlements.

PBR is a regulatory tool that has been developed by regulators to enhance the performance of utilities through the use of incentives beyond those found in traditional cost of service regulation. These incentives are provided to incent behaviour that is desired by the customers, usually the pursuit of greater efficiencies and improved customer service. A common theme that emerges is the need to break or weaken the link between costs and prices so that utilities have greater incentives to reduce costs.

As discussed earlier, traditional regulation establishes a link between the regulated firm's prices and its costs. While this link is generally viewed as the basis for equitable rates, tying prices to costs reduces the utility's incentive to reduce costs and increase market responsiveness, since gains from these efforts will only be available to the utility until the gains are rebased in the next rate determination. In traditional regulation, rebasing usually occurs in the short term. Similarly, the firm's incentive to innovate is also attenuated since in the short term the costs of such innovation are not recovered by the utility; thus, the firm's gains from innovation are constrained. Further, the utility's earnings under traditional regulation are tied to the utility's rate base, creating an environment in which there is a link between earnings and capital investments.

While cost of service regulation has proved reasonably effective at achieving the investment in utility plant required to provide service to customers, changes in the economy from capital intensive industries to more adaptive forms of enterprises has increasingly led many to conclude that the cost of service methodology may be too slow, too rigid, and too complex. The adoption of a regulatory framework that is more responsive and more flexible is also a consistent theme.

3. PBR DESIGN PRINCIPLES AND ATTRIBUTES

The following is a list of principles developed by BC Gas that it believes should be considered in the design of a PBR plan. The PBR plan should:

- align the interest of customers and the utility;
- be administratively simple and easy to understand;
- be sufficiently comprehensive to allow the utility to manage its business in a more holistic fashion and should not focus unduly or distort individual business parameters. The utility should be motivated to achieve benefits in optimizing all areas of its activities (O&M expense, capital expenditures, capital costs and revenue generation) in an integrated fashion;
- promote efficiency and motivate economic decision making by the utility, minimizing biases (such as capital spending vs. O&M spending);
- be transparent and facilitate communication to allow stakeholders to remain aware of the ongoing operations and activities of the company;
- encourage innovation and continuous improvement throughout its term, and should not discourage such activity as the end of its term nears;
- allow the utility flexibility to respond to changing and varied circumstances;
- have a sufficiently long term to permit opportunities for the utility to recover one-time expenditures related to gains in efficiency and to earn enhanced return in the event of superior performance; and
- be oriented to a user-pay approach for managing new costs and providing greater focus on new developments paying the cost of new infrastructure.

It has become clear that customers also would favour a methodology that provides:

- greater rate certainty and predictability;
- safe, reliable and good quality service;
- new products and services that respond to customers interests; and
- a financially viable and sound utility.

In the materials filed with this Application, the Company has forecast a range of potential rate impacts over five years under the traditional cost of service regulatory methodology. It is the Company's belief that a new comprehensive multi-year PBR plan will generate results that are better than traditional cost of service for all parties.

BC Gas believes that the views expressed in this section of the Application provide a foundation from which to develop such a framework. BC Gas recommends that the process for establishing a comprehensive multi-year regulatory framework be conducted in conjunction with the review of the 2003 rates applied-for in this Application thereby enabling implementation of a new long-term regulatory plan effective January 1, 2003.

4. DRSM MECHANISM 2003 - 2007

BC Gas believes that a long-term regulatory mechanism that relates the Company's delivery charges (excluding gas costs) to the Consumer Price Index (B.C.) index is the most appropriate methodology at this time to determine the rates of BC Gas. At a high level, the DRSM model is expressed as follows:

$R_1 = R_0$ (I+CPI) where:

R_0 = the current year's rates

R_1 = the subsequent year's rates

CPI = forecast Consumer Price Index for B.C. for period R_1

This mechanism would operate with the current GCRA and RSAM mechanism and with a limited number of other rate adjustments (discussed below). An array of effective service quality measures would support this mechanism. BC Gas believes that the above-mentioned mechanism is responsive to customer and Company desires and represents an appropriate evolution of the PBR framework applicable to BC Gas.

This methodology focuses more on the delivery charges to customers than on the individual costs and revenues of the Company. While gas commodity costs form approximately 65% of customers' rates, the Company has the greatest control over the portion of costs that relates to the delivery service. BC Gas believes that key elements of the current regulatory methodology should be retained, such as the continuation of the RSAM, the GCRA, the Gas Supply Mitigation Incentive Plan and BCUC sponsored Annual Reviews

BC Gas believes that this methodology would benefit customers in several ways. It would:

- provide a higher degree of rate certainty and predictability for customers;
- provide a delivery charge setting mechanism with the potential for no real increases in the customers' delivery charges;

- produce lower rates for gas delivery service than would otherwise be expected under traditional rate making;
- provide greater incentives for the Company to reduce its total cost of service, consistent with the maintenance of adequate, efficient, just and reasonable service;
- shift the risk for certain revenues and margin away from customers and onto the Company;
- allow the Company to optimize its mix of inputs to meet customer requirements;
- provide a framework that will allow the Company to offer new and innovative services to its customers; and
- ensure quality of service to customers is assured through a more comprehensive set of service quality measures.

Customers would be subject to changes in delivery charges related to changes in CPI, while continuing to have assurance of safe, reliable, and efficient service. Under the mechanism, customers' rates would be insulated to an unprecedented degree from impacts such as:

- changes in long-term and short-term debt;
- changes in authorized rates of return on equity;
- changes in economic conditions;
- fluctuations in industrial revenues;
- variations in operation costs;
- changes in inflation from forecast;
- variations in customer additions; and
- variations in the costs of capital additions including major projects requiring Certificates of Public Convenience and Necessity.

Compared to the range of rate impacts that could result from these factors under the traditional mode of regulation, this mechanism provides considerable customer benefits.

5. PBR PLAN ELEMENTS

BC Gas is requesting a PBR Plan that creates a rate making methodology for setting its delivery rates to customers called a Delivery Rate Setting Mechanism (DRSM) which will operate for a minimum term of five years. This basic structure of the DRSM can be simply described as follows:

$R_1 = R_0$ (I+CPI) where:

R_0 = the current year's rates

R_1 = the subsequent year's rates

CPI = forecast Consumer Price Index for B.C. for period R_1

The DRSM does not relate to the treatment of gas commodity costs or related incentive mechanisms. The GCRA would continue to operate. The RSAM would continue to operate. There would also be potential adjustments to rates, as discussed below.

Key elements of any PBR methodology, including the DRSM, are:

- base delivery rates and adjustments;
- term;
- rate flexibility;
- new products and services;
- exogenous factors;
- service quality indicators;
- sharing mechanism;
- extension of term; and
- phasing out of benefits at end of term.

These elements, and other features of the DRSM, are discussed below.

a. Delivery Charges

The DRSM would start with the delivery rates, plus existing riders, as approved for 2003. The DRSM will operate for at least five years (2003 – 2007). Price changes for each of the customer rate classes will be determined in advance of each year. Rate riders would continue to be determined annually for specific items.

b. Base Rates and Adjustments

Base Rates are the 2003 approved rates for each customer class. For 2003, the rates will also be adjusted to reflect changes to the authorized rate of return on common equity under the Commission's automatic ROE adjustment mechanism that is determined in late 2002. In terms of determining rates for subsequent years, the rates would be adjusted annually by an inflation factor. This factor should be the forecast CPI (B.C.) that was used in the 1998 - 2001 PBR plan. Its use during this period proved that it was a stable, understandable, readily available index and has not led to any discernible distortions or unintended results.

In all other respects, except for items discussed below, no other adjustments to the delivery margin portion of customers' rates would be permitted.

c. Adjustments for Uncontrollable Items

These adjustments would include taxes; changes in accounting standards; and Legislative/Regulatory/Administrative changes, orders or directives (including unbundling). Financial impacts from changes of this type will continue to be flowthroughs as has been the case for a number of years.

In this Application, BC Gas is seeking a deferral account that would capture the variance in property taxes from that which is forecast, and a three-year amortization of the variance through a rate rider. The same manner of dealing with property tax variance would also apply under the DRSM.

The deferral account that BC Gas is seeking for variances in property taxes will also collect variances in other, and new, government taxes, charges and levies. Under the DRSM, the variances to be collected in the deferral account would be variances from the level of taxes, charges and levies that have been announced (e.g. changes from the corporate income tax rates referenced in Section E), and new taxes charges and levies.

As discussed in Section E of the Application, accounting standards and policies may have implications for BC Gas. If accounting standards or policies change and if the change affects BC Gas, then under the DRSM customers' rates would be adjusted to reflect the impact of the change.

In recent years there have been discussions about measures to allow residential and commercial customers to acquire gas commodity from entities other than BC Gas. This has been referred to as "Unbundling". If Unbundling proceeds the recovery of the costs of BC Gas associated with the Unbundling process will need to be determined. Any such costs would not be within the DRSM and an adjustment to customers' rates would be necessary to recover those costs.

To the extent there are additional fees or levies to BC Gas from the Commission, or the Commission orders or directs BC Gas to undertake additional expenditures, customer rates would be adjusted to recover the additional costs.

"Downloading" of costs and responsibilities from government and its agencies has occurred and is projected to continue. To the extent it is able to do so, BC Gas would seek recovery of such downloading through a "user-fee" approach; and if "user-fee" recovery were not possible, an adjustment to customers' rates would be required.

The capital expenditures for 2003 - 2007 discussed in Section C of the Application include expenditures related to the Transmission Pipeline Integrity Plan. If a portion of the expenditures forecast to be funded under that plan were required to be treated as an expense, rather than a capital expenditures, then an adjustment to rates would be necessary to compensate for that additional expense.

SCP third party revenues are uncertain. To the extent there is a variance from forecast of those revenues, the variance would be collected in a deferral account and customers' rates would be adjusted to credit or recover the variance.

During the first five years of the DRSM, customers' rates would not be adjusted for CPCN capital expenditures. Subsequent to that period, large CPCN projects may require rate adjustments.

d. Term

BC Gas proposes a base term of five years, 2003 to 2007. The term of the last PBR was initially three years and subsequently extended to four years, and then rates were frozen in year five through a withdrawal of BC Gas' 2002 Revenue Requirement Application. The five-year minimum period for the DRSM will enable the Company to undertake activities that traditionally have not been attainable and to implement initiatives that have greater risk. As the "low-hanging fruit" has largely been harvested, BC Gas requires adequate time to invest in systems and process change initiatives to realize benefits, and design and promote new products and services that customers will value. Such investments must permit a reasonable return to the utility's shareholders (i.e. an appropriate financial payback). The last PBR Plan contained a $3 million contribution from customers' rates to assist in restructuring. An allowance for restructuring costs must be recognized as part of the DRSM, either as a contribution from customers or through other elements of the Plan.

As discussed elsewhere, considerable effort has been expended by the Company in the area of reducing O&M expenditures. Opportunities for further efficiencies are limited and focus on other areas such as the management of capital and revenues are required. However, these two areas require a longer term to permit payback; for capital because of the low depreciation rates; for revenues programs because of a higher reliance on development and new process implementation.

BC Gas believes that should the DRSM operate appropriately during the first three years, then BC Gas would have the ability to elect to extend the Plan for a subsequent three-year period by providing notice at the Annual Review immediately preceding the end of the third year. This extension provision would provide a longer planning horizon for the Company and customers and also provide continued rate certainty for customers.

e. Phase-out of Benefits at End of Term

One of the key attributes of an effective PBR Plan is the aspect of motivating the Company to seek out productivity continuously. While the longer term of the DRSM attempts to achieve this, it is also apparent that pay back economics of initiatives become less achievable as the Plan term nears its end. To overcome this challenge, BC Gas proposes that a phase-out of benefits from activities be instituted at the end of a term. This mechanism provides the Company with the motivation to seek continuous improvement throughout the whole of the term.

f. Current Regulatory Accounting Methodologies

Current accounting treatments prescribed by the Commission will remain in effect during the period of the delivery rate setting mechanism proposal. This includes maintaining the GCRA and RSAM rate stabilization accounts, the taxes payable method of accounting for income taxes, the regulatory accounting treatment for CPCNs set in the 1998 – 2001 PBR Plan, and accounting for certain assets and the rate stabilization accounts on a net of realized tax savings basis. The accounting for property, plant & equipment will include an allocation of overhead costs and an allowance for funds used during construction. Depreciation rates approved by the BCUC will remain and the current treatment of property, plant & equipment retirements will continue. Deferred charges previously approved will continue to be amortized in the prescribed manner and will continue to include long-term debt issue costs and any other costs the Commission orders the Company to defer.

g. Exogenous Factors: Non-routine Items

Consistent with most longer-term PBR proposals, BC Gas proposes a mechanism to adjust rates for positive and negative cost changes beyond the reasonable control of the Company. BC Gas proposes that this factor adjust for material matters, such as revenue losses, property damage, remediation and recovery costs which arise from events which are out of the reasonable control of BC Gas, such as catastrophic events in the nature of a major seismic event in the service area or an act of war or violence. Further, under this DRSM, BC Gas seeks the continuation of the deferral account recovery as set out under paragraph 7 of the Application Section.

h. Sharing Mechanism

Sharing mechanisms are generally put in place to allow for participation by ratepayers in the gains or losses of the utility. They are also put in place to mitigate against unintended results of such a new PBR Plan as windfall profits earned by the Company or unexpectedly low earnings.

BC Gas proposes that the DRSM contain an earning sharing mechanism that incorporates a collar within which the Company assumes all risk. The collar would be ±200 basis points around the Reference ROE (discussed below). Sharing would occur on a 50/50 basis between customers and the Company outside this band, up to 300 basis points from the Reference ROE. Thereafter, the DRSM would be subject to review as discussed in the Off Ramps section. Within the ±200 basis point collar, BC Gas would absorb all benefits as well as all risks.

The “collar” provides the strongest incentive for the Company to seek productivity gains and realize efficiencies. This view is further supported in the December 2000 report of the NARUC sponsored, “PBR for Distribution Utilities”, which stated:

> “There are three important points about sharing mechanisms. Two points argue against sharing mechanisms and the third argues in their favour.

1. The “compared-to-what” test demonstrates that traditional cost-of-service regulation has no earnings cap or sharing mechanism. The utility keeps 100% of any savings and incurs 100% of any cost increases. Thus, to the extent that an increased cost-cutting incentive is a high priority, incorporating a sharing mechanism in a PBR will probably mean that the PBR has weaker cost-cutting incentives than cost-of-service regulation.

2. Most sharing mechanisms purport to be symmetrical, with the sharing of excess profits matching the sharing of losses. In reality, any earnings-based sharing mechanism is inherently biased because earnings can be manipulated. The timing of expenses, as well as spending on discretionary items, gives utility management the ability to change earnings. This, in turn, reduces the amount of sharing required. To the extent earnings can be thus “managed,” it is safe to assume they will be managed to the benefit of utility managers and shareholders, rather than consumers.

3. Sharing mechanisms provide some level of insurance for the utility and consumers against the risk that something in the PBR will go awry. A sharing mechanism can blunt the effect of windfall profits on the utility or, in the case of downside sharing, of unexpectedly low earnings.

   Reconciling these perspectives calls for a sharing mechanism that takes effect only if earnings fall outside a wide range. The range need not be symmetrical. Inside the range, the sharing mechanism has no effect and hence does not blunt the cost-cutting incentives. If something goes wrong and earnings fall outside the range, the PBR probably loses its effect anyway, and some sort of insurance, or revenue stabilizing, mechanism is called for.”

i. Reference ROE

As discussed in detail below, under the DRSM BC Gas will be subject to significant risk beyond that to which it would be subject in traditional cost of service regulation. In recognition of this substantial increase in risk, the return on equity to be used as the midpoint for the ±200 basis point collar is the year to year return on equity for BC Gas allowed pursuant to the BCUC generic ROE adjustment mechanism plus 100 basis points.

The combination of the DRSM as a whole combined with this mechanism will provide enduring benefits to customers.

It should be noted that BC Gas is NOT seeking to adjust its rates to recover from customers any additional amount to fund a higher ROE. Rather, the Reference ROE is only for determining the collar of the sharing mechanism.

j. Flexibility

A cornerstone to the DRSM is the ability of the Company to have a greater level of flexibility in order to manage the higher level of risk for the Company created by the DRSM, and which it is prepared to absorb in order to provide the rate certainty and service quality that customers have requested.

The flexibility desired is in the ability to seek out new revenue opportunities; optimize all inputs and deal with affiliated companies without all the strictures of the Transfer Pricing Policy.

i) Revenue Opportunities

The ability to focus on the generation and retention of revenues will be a key to meet the challenges of the DRSM. The avenues where the Company believes opportunities exist are:

- Provision of new products and services to optimize the utilization of facilities or business units. BC Gas seeks the ability to develop and offer a variety of products and services that would deliver value to customers. These new products and services would be provided at the risk of the Company and would have no incremental funding in rates. This would provide a platform for growth through a stronger customer oriented incentive.

- To enter into transactions with affiliates for the provision or procurement of services and products, free of the constraints of transfer pricing rules. This is appropriate since the DRSM constrains the Company's rates and forces the Company to optimize its resources within this constraint.

- To have tariff flexibility to price at below tariffed rates to retain existing customers, or attract new customers.

ii) Input Optimization

Another key aspect of the DRSM is the ability of the Company to view its costs as an integrated mix of resources that can be assessed and utilized in accordance with the needs of the Company to meet its responsibilities. Rather than categorize capital into discrete groups as in its previous PBR, what is sought in this new model is for the Company to have the flexibility to make capital expenditures in the area which has the greatest business imperative in terms of the Company meeting its responsibilities; and to substitute capital and O&M expenditures as the Company deems most efficient. Over a longer term, the Company foresees that various influences could impact the capital requirements of the Company which cannot be reasonably predicted today. In any given year, there could be requirements that necessitate greater expenditures in mains and services, greater than the level arising from the normal forecasting methodology. Under the DRSM, the Company would reduce its expenditure in another area, such as general plant to meet the capital requirement. This flexibility becomes even more vital when considered from the perspective that the Company will take on responsibility during the initial five years of the DRSM to fund the identified CPCN's without adjustment in customers' rates.

iii) Code of Conduct and Transfer Pricing Policy

The current Transfer Pricing Policy ("TPP") and Code of Conduct ("CoC") already provide some flexibility by allowing BC Gas Utility to apply for approvals for policy variances. However, this approach has become too administratively complex and burdensome in the current working business environment where quick decisions to reallocate resources temporarily need to be made, particularly when opportunities are short-term or small dollar value transactions. BC Gas believes the benefit of five years of experience of working with the current rules has demonstrated that there is an opportunity to relax some of the policy constraints without impairing the functioning of the competitive market or customer service limits. In fact, it is clear that due to certain provisions in the current CoC customer needs currently are not being met.

The provision of services to affiliates by BC Gas allows the Company to access economies of scale and scope that would otherwise not be available. In addition, the provision of services to affiliates by the Company allows the Company to shed costs associated with resources that may be temporarily surplus. Typical examples of services that BC Gas may be able to offer affiliates include legal, human resources, finance, and IT. The sharing of resources is a realistic, practical approach to the effective utilization of resources especially where there is a commonality of purposes (such as with a common owner and common customer, as in the case with BC Gas). Item 6 (Equitable Access to Services) of the CoC should be deleted.

A further reason to review the TPP and CoC is that after successive years of PBR, BC Gas has been able to extract significant productivity savings from its cost structure. However, these opportunities are becoming less and less available and new means of delivering productivity savings to customers must be found. Introducing increased flexibility in the CoC and ensuring the most appropriate transfer prices are embedded in the TPP will help meet this challenge.

An example of the conservatism inherent in the original transfer pricing rules is the requirement to charge the greater of market or fully allocated cost, which impairs the Company's ability to achieve productivity gains. Requiring the greater of market price or fully allocated cost ensures that where market alternatives exist which are lower than the utility's costs, the NRB would be better off not using the utility's resources. The limitation with the Transfer Price at fully allocated cost is that this price will prevent or discourage economic transactions if the market price is above incremental cost but below fully allocated cost. Ultimately, this approach biases the Company's Transfer Price upwards to a point where BC Gas may be foregoing opportunities to reduce its costs even though there may be ample capacity to meet the NRBs requirements. Moving towards a floor price of incremental cost, together with an incentive through PBR to maximize transfer-pricing revenue, would provide increased opportunities for enhanced cost recovery with no adverse impact on customers. BC Gas recommends a change to the TPP to include transfer pricing at market prices where feasible and practical, and incremental cost as the floor price for transactions between the utility and non-regulated affiliates.

Brand names, which provide a common identity to an array of services, can help to reduce customers' search and information costs, while providing economies of scope to the firm. Logos can provide a common visual identity to a firm's various products. Restrictions on the ability of utilities and utility affiliates to communicate to customers does not benefit consumers or improve the efficiency of competition.

The current restrictions on the use of the BC Gas name is really only relevant for gas marketing where there is a fledgling competitive market. In an already competitive market, it is unclear why this is a requirement. Further, the BC Gas name and logo are an asset of the BC Gas Inc. shareholder.

The BC Gas brand holds meaning for consumers. Consumers know BC Gas as a trusted service provider. The current CoC restricts the use of the BC Gas name by newly established NRBs, when the utility name is used as the primary identifier in British Columbia. This prevents customers from having information available. Item 9 of the CoC (Use of Utility Name) should also be deleted in order to allow BC Gas to use its name.

k. Off Ramps

This term is found in PBR plans to address circumstances which trigger a regulatory review of the PBR Plan. This normally would occur when a serious flaw in the performance of the Plan has been identified and is one not foreseen before its introduction. Under a regulatory review the options would vary from an adjustment of certain plan parameters to terminating the Plan.

The parameters which are proposed for the DRSM to trigger an off ramp regulatory review are the following:

- if the achieved ROE of the Company exceeds or drops below the then current Reference ROE by 300 basis points; and
- if there is a serious degradation of the Service Quality Indicators.

l. Items External to the DRSM

Rate riders arising under Commission orders or directions would not be affected by the DRSM.

BC Gas pays fees under franchise agreements and operating agreements with municipalities in the Interior. Discussions have been underway with municipalities to revise the manner in which those fees are calculated. The fees paid to municipalities under those agreements do not form part of the delivery margin portion of a customer's rate. Revisions to the municipal fees, and any resulting impact on the amount paid by customers, is external to the DRSM.

PST and GST is payable by customers on the amount of the BC Gas bill. These taxes payable by customers, and any changes thereto, are external to the DRSM.

As noted above, the GCRA and the RSAM account would continue in place, and rate riders would flow through amortizations of those accounts.

m. Service Quality Indicators

BC Gas believes that maintaining a high level of service quality and customer value is critical to the success of the Company under any regulatory regime. One of the regulatory concerns is that as a result of the implementation of PBR regimes there may be the potential for deterioration of service quality in favour of financial objectives. Service Quality Indicators (SQIs) are important to offset the concern that a utility will seek the financial incentive to reduce costs at the expense of service and system standards.

SQIs have been a key component of the current PBR and BC Gas proposes to continue with this feature. Annually, BC Gas will report to the BCUC and stakeholders to allow a comparison of the performance of the utility against the targets set for each of the SQIs. The role of SQIs is to provide assurance that certain operating (and customer interaction) standards will be maintained throughout the term of the DRSM. Service quality results will also be reviewed at the annual workshops. An expanded list of SQIs is proposed as follows:

INDICATORS	PREVENTATIVE MAINTENANCE SUB-MEASURES	BILLING SUB-MEASURES
Response time to site for emergency calls;	Transmission Pressure Pipe Cathodic Protection Close Interval Survey (% of kilometers surveyed).	Percentage of bills accurate based upon input data.
Percent of response time by a person for a emergency call;	Distribution and Intermediate Pressure Leak survey (% of kilometers surveyed).	Percentage of bills delivered to Canada Post within two days of the date that the statement file is created.
Percent of customer bills produced meeting accuracy, timeliness and completion;	Cathodic Protection Rectifier Operational Survey (% of rectifiers surveyed)	Percentage of customers billed within two business days of the scheduled billing date.
Percent of scheduled preventive maintenance activities completed;	Regulator Station Operational Survey (% of stations surveyed)	
	Transmission Pressure Line Survey (Line Patrol and Leak Survey) [% of kilometers surveyed]	

n. BCUC Annual Reviews

The 1998-2001 PBR Plan had an annual review process through a BCUC sponsored proceeding. This has been a positive feature that provided a formal venue for all parties to remain in contact with the Company, to review the performance and activities of the Company, to understand the issues and challenges faced, and to provide comments and feedback. The annual review was also the forum that reviewed business parameters that were reset each year in the 1998 - 2001 PBR Plan. BC Gas proposes to continue this process. Under the DRSM, the Commission would review annually any rate adjustments resulting from the operation of the Plan.

BC Gas proposes to conduct annual workshops with customers, the Commission, its Staff and interested parties to review the operation of the DRSM and rate adjustments prior to January 1 of each year. This process will provide customers, all interested parties and the Commission an opportunity to remain informed about the activities of the Company and provide feedback to BC Gas and the Commission.

6. CUSTOMER ASSISTANCE FUND

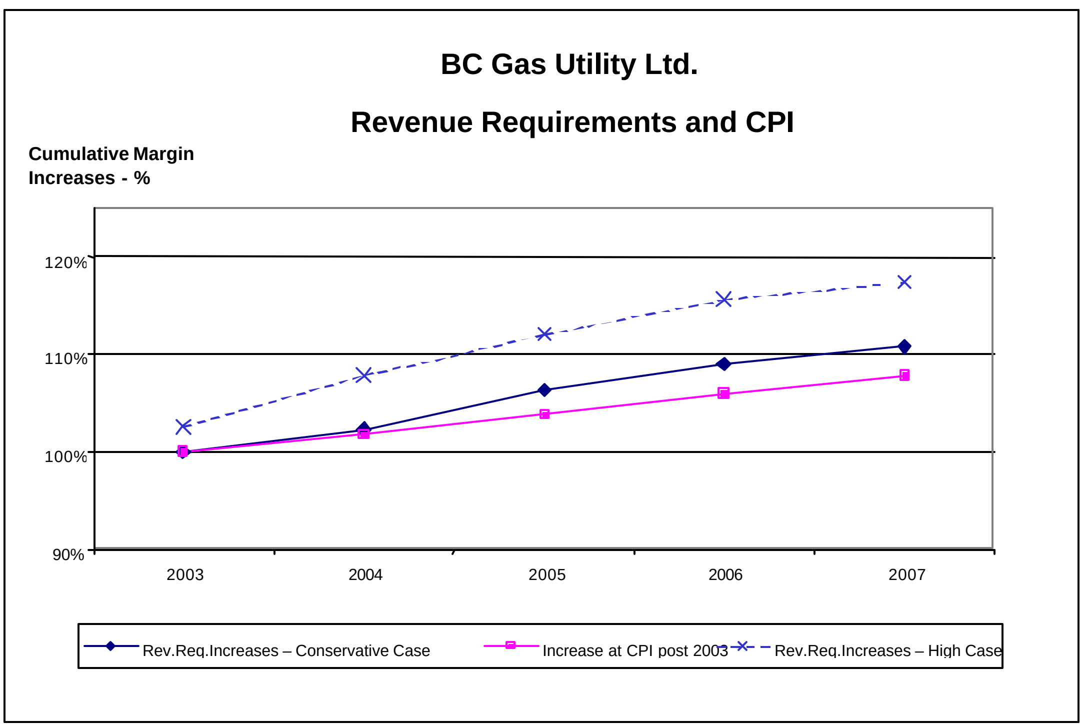
As part of the BC Gas DRSM proposal, the Company proposes to create a fund to assist the most needy of its customers in paying their gas bill. BC Gas shareholders intend to establish this fund by way of a one-time contribution of approximately $2 million. The fund would be to assist customers in dealing with potential gas rate volatility. It should be noted that this fund would NOT be funded in customer rates. Rather, it would be funded by the shareholders of the Company for its customers.

This fund would demonstrate an "up-front" commitment by the Company of benefits of a comprehensive multi-year PBR. It is the delivery of a tangible outcome for customers that would not otherwise arise. Notwithstanding the Company's assumption of greater risk under the DRSM, BC Gas believes that over a longer term, value can be generated that could support initiatives such as this. It reinforces the view that greater alignment can be achieved between the Company and customers through a more comprehensive PBR Plan.

7. FIVE YEAR FORECAST

To provide an illustration of the benefit of the DRSM, BC Gas has forecast potential revenue requirement impacts to customers for the period 2003 – 2007 under a traditional cost of service type of regulation. The chart below shows a range of impacts between a conservative case and a high case.

The solid line represents the projected costs of the Company from 2003-2007 based on conservative assumptions. The dashed lined represents a high case for the costs of the Company for the same period. The elements which form the high case include reduced revenues from the industrial sector, and higher interest rates, authorized rates of return on equity, capital expenditures, depreciation and operating costs than projected in the conservative case. It is difficult to predict with precision what the Company's revenue requirements will be over the next five years. Such a prediction is especially difficult in view of the uncertainty regarding the various cost pressures facing BC Gas. The chart compares a reasonable range of revenue requirement forecasts versus projected CPI increases. A DRSM based on CPI would transfer the risk of potential future cost increases to the Company and should be preferable to customers.



8. PROFILE OF THE UTILITY UNDER THE DRSM

This following section reviews the additional risks that BC Gas is prepared to manage under the proposed DRSM.

a. Price Volatility

Under the traditional mode of ratemaking, the annual rate setting process determines the rates for the ensuing year. The level and direction of customers' annual rates both in terms of gas commodity and delivery rates are not known with certainty.

Under the DRSM the delivery rates will have greater certainty and predictability as the proposed method provides few business parameters to be varied in an annual rate setting process. This is of benefit to customers as rate certainty is one of their key interests.

b. Variations in Industrial Forecast Use

Under the traditional mode, industrial revenues are forecast each year in the annual rate determination process. If the revenue forecast as accepted by the Commission declines from the previous year, this reduction will be reflected in higher rates to customers (all other things remaining the same).

Under the DRSM, customers will be insulated from the effect of changes in revenues from industrial customers.

c. Changes in Customer Growth Rate

Under the traditional rate setting methodology, customer additions are forecast each year in the annual rate determination process. The effect of reduced customer growth is reflected in lower revenues, which is reflected in rates for the following year. Under the DRSM, customers will be insulated from year to year variations in customer growth. To the extent there are variances in customer growth, the Company will be at risk.

d. Changing Economic Conditions

The impact of economic conditions is reflected in various rate impacts under the traditional mode, such as those associated with revenue and expense forecasts. BC Gas typically manages variances within the test year and the effects of economic conditions are taken into account in the subsequent year; customers absorb the impacts of changing economic conditions over the longer term.

Under the DRSM, BC Gas assumes the risk of changing economic conditions during the term. Exceptions to this are the RSAM and the zone above and below the 200 basis point collar.

e. O&M Expense Variances

The Company will manage all O&M expense variances during the term of the DRSM and insulate the customers, including higher insurance premiums and bad debts. BC Gas provides services to CustomerWorks LP and receives payment that is credited to the cost of service. CustomerWorks can terminate the various services on notice to BC Gas. Under the DRSM BC Gas would not seek to adjust rates if those payments from CustomerWorks are reduced or eliminated.

f. Capital Expenditure Variances

The Company will manage capital expenditure variances during the term of the DRSM and insulate the customers.

g. Interest Rates Variances

In the past, a deferred account has been in place to capture variances from forecasts of short and long-term interest rates. Under the DRSM, BC Gas will assume the interest rate risks relating to short term and long-term borrowing costs.

h. Changes in the Authorized Level of Return on Common Equity

BC Gas rates have been adjusted for changes in its authorized level of return on common equity pursuant to the BCUC generic ROE adjustment formula. Customers' rates fluctuate based on the application of the formula as well as the amount of rate base.

It should be noted that considerable efforts are being undertaken by utilities across Canada to seek approval for significant increases in ROE from their regulators. BC Gas is choosing not to engage in this type of process with its customers. Customers' rates will be adjusted for the 2003 ROE determined pursuant to the Commission's adjustment mechanism, but beyond that during the DRSM there will be no further adjustment to rates for ROE changes. Rather, under the DRSM, if BC Gas earns superior returns, it will be through its own efforts as opposed to an increase in the rates of its customers.

In summary, the foregoing illustrates that BC Gas is willing to assume greater risk during the term of the DRSM, and that customers will be insulated from those risks. While the

Company will absorb greater risk, customers are provided with greater rate certainty and predictability.

9. CONCLUSION

In conclusion, BC Gas submits that the DRSM is a reasonable evolution of the regulatory methodology applicable for BC Gas. The DRSM will allow the determination of rates that are just and reasonable and will allow the Company to continue to provide safe, reliable and secure service. The DRSM is an appropriate mechanism for setting the Company's rates for the years 2003 – 2007.

The DRSM is viewed by BC Gas as an important component in meeting the challenge of a changing business environment. The five year minimum term is intended to provide the Company sufficient opportunity to recoup the expenditures necessary to achieve on-going productivity leading to enduring benefits for our customers.

The Commission should establish a negotiated settlement process to be used for consideration of the DRSM.

H. FINANCIAL SCHEDULES

This section provides the financial schedules supporting the Company’s 2003 revenue requirement request. Included are details with respect to the components of rate base, income and earned return, income taxes and return on rate base / capital structure. The materials also contain continuity schedules and historical information to support the 2003 revenue requirement components.

Beyond the 2003 and historical information Section H also provides forecasts of the various rate base and revenue requirement elements for the years 2004 to 2007. The calculations of the annual revenue requirements in this period incorporate the changes discussed in Section E to deprecation rates in 2004 and to overheads capitalized in 2005.

An index is included identifying the key revenue requirement component covered under each numbered tab. Additional indices are included in the longer tabs for further assistance in finding the various schedules.

BC GAS UTILITY LTD
COST OF SERVICE
FOR THE YEARS ENDING DECEMBER 31, 2003 TO 2007

BC GAS UTILITY LTD.

SUMMARY OF RATE INCREASE REQUIRED
FOR THE YEAR ENDING DECEMBER 31, 2003
($000)

Line No.	Particulars	2001	2003 Rates 1, 2, 3 and 23	2003 Rates 4, 5 and 6	2003 Other	2003 Bypass and Special Rates	2003 Total	Change
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	RATE INCREASE REQUIRED							
2								
3	Gas Sales and Transportation Revenue,							
4	At Prior Year's Rates	$1,316,127	$1,109,253	$52,213	$40,022	$12,170	$1,213,658	($102,469)
5								
6	Add - Other Revenue Related to SCP Third Party							
7	Revenue / Centra BC (PCEC)	16,559	0	0	0	12,443	12,443	(4,116)
8								
9	Total Revenue	1,332,686	1,109,253	52,213	40,022	24,613	1,226,101	(106,585)
10								
11	Less - Cost of Gas	(852,158)	(718,059)	(39,281)	(1,389)	(388)	(759,117)	93,041
12								
13	**Gross Margin**	$480,528	$391,194	$12,932	$38,633	$24,225	$466,984	($13,544)
14								
15	**Revenue Deficiency**		$3,709	$123	$366	$0	$4,198	
16	- Use Rate Change		11,167	0	0	0	11,167	
17	Total Revenue Deficiency		$14,876	$123	$366	$0	$15,365	
18								
19	**Revenue Deficiency as a % of Gross Margin**		0.95%	0.95%	0.95%	0.00%	0.90%	
20	- Use Rate Change		2.85%	0.00%	0.00%	0.00%	2.39%	
21	Rate Increase as a % of Gross Margin		3.80%	0.95%	0.95%	0.00%	3.29%	
22								
23	**Revenue Deficiency as a % of Total Revenue**		0.33%	0.24%	0.91%	0.00%	0.34%	
24	- Use Rate Change		1.01%	0.00%	0.00%	0.00%	0.91%	
25	Rate Increase as a % of Total Revenue		1.34%	0.24%	0.91%	0.00%	1.25%	

BC GAS UTILITY LTD.

SUMMARY OF RATE INCREASE REQUIRED
FOR THE YEARS ENDING DECEMBER 31, 2004 AND 2005
($000)

Line No.	Particulars	2004 Core	2004 Non-Core	2004 Bypass and Special Rates	2004 Total	2005 Core	2005 Non-Core	2005 Bypass and Special Rates	2005 Total
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	RATE INCREASE REQUIRED								
2									
3	Gas Sales and Transportation Revenue,								
4	At Prior Year's Rates	$1,179,167	$48,968	$12,172	$1,240,307	$1,199,778	$50,239	$12,174	$1,262,191
5									
6	Add - Other Revenue Related to SCP Third Party								
7	Revenue / Centra BC (PCEC)	0	0	12,241	12,241	0	0	12,328	12,328
8									
9	Total Revenue	1,179,167	48,968	24,413	1,252,548	1,199,778	50,239	24,502	1,274,519
10									
11	Less - Cost of Gas	(764,437)	(1,434)	(438)	(766,309)	(771,512)	(1,444)	(458)	(773,414)
12									
13	Gross Margin	$414,730	$47,534	$23,975	$486,239	$428,266	$48,795	$24,044	$501,105
14									
15	Revenue Deficiency	$9,402	$1,078	$0	$10,480	$17,035	$1,941	$0	$18,976
16									
17	Revenue Deficiency as a % of Gross Margin	2.27%	2.27%	0.00%	2.16%	3.98%	3.98%	0.00%	3.79%
18									
19	Revenue Deficiency as a % of Total Revenue	0.80%	2.20%	0.00%	0.84%	1.42%	3.86%	0.00%	1.49%

BC GAS UTILITY LTD.

SUMMARY OF RATE INCREASE REQUIRED
FOR THE YEARS ENDING DECEMBER 31, 2006 AND 2007
($000)

Line No.	Particulars	2006 Core	2006 Non-Core	2006 Bypass and Special Rates	2006 Total	2007 Core	2007 Non-Core	2007 Bypass and Special Rates	2007 Total
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	RATE INCREASE REQUIRED								
2									
3	Gas Sales and Transportation Revenue,								
4	At Prior Year's Rates	$1,228,280	$52,378	$12,174	$1,292,832	$1,252,620	$53,915	$12,224	$1,318,759
5									
6	Add - Other Revenue Related to SCP Third Party								
7	Revenue / Centra BC (PCEC)	0	0	12,329	12,329	0	0	12,330	12,330
8									
9	Total Revenue	1,228,280	52,378	24,503	1,305,161	1,252,620	53,915	24,554	1,331,089
10									
11	Less - Cost of Gas	(778,637)	(1,453)	(517)	(780,607)	(785,827)	(1,457)	(401)	(787,685)
12									
13	Gross Margin	$449,643	$50,925	$23,986	$524,554	$466,793	$52,458	$24,153	$543,404
14									
15	Revenue Deficiency	$12,612	$1,428	$0	$14,040	$8,200	$921	$0	$9,121
16									
17	Revenue Deficiency as a % of Gross Margin	2.80%	2.80%	0.00%	2.68%	1.76%	1.76%	0.00%	1.68%
18									
19	Revenue Deficiency as a % of Total Revenue	1.03%	2.73%	0.00%	1.08%	0.65%	1.71%	0.00%	0.69%

BC GAS UTILITY LTD.

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2003
($000)

Line No.	Particulars	2001	2003 Present Rates	2003 Adjustments	2003 Revised Rates	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Plant in Service, Beginning	$2,110,015	$2,711,233	$0	$2,711,233	$601,218	
2	CPCNs	434,195	31,845	0	31,845	(402,350)	- Tab 3, Page 2.2
3							
4	Additions	107,092	119,102	0	119,102	12,010	- Tab 3, Page 2.2
5	Disposals	(15,980)	(13,067)	0	(13,067)	2,913	- Tab 3, Page 2.2
6							
7	Plant in Service, Ending	2,635,322	2,849,113	0	2,849,113	213,791	
8							
9	Add - Intangible Plant	837	837	0	837	0	
10							
11		2,636,159	2,849,950	0	2,849,950	213,791	
12							
13	Contributions In Aid of Construction	(133,691)	(148,436)	0	(148,436)	(14,745)	- Tab 3, Page 4.1
14							
15	Less - Accumulated Depreciation	(428,130)	(527,002)	0	(527,002)	(98,872)	- Tab 4, Page 2
16							
17							
18	Net Plant in Service, Ending	$2,074,338	$2,174,512	$0	$2,174,512	$100,174	
19							
20							
21	Net Plant in Service, Beginning	$2,058,968	$2,138,353	$0	$2,138,353	$79,385	- Tab 3, Page 4.4
22							
23							
24	Net Plant in Service, Mid-Year	$2,066,653	$2,156,433	$0	$2,156,433	$89,780	
25	Adjustment to 13-Month Average	0	0	0	0	0	
26	Construction Advances	(4,000)	(1,000)	0	(1,000)	3,000	
27	Work in Progress, No AFUDC	3,748	4,200	0	4,200	452	
28	Unamortized Deferred Charges	76,796	31,546	0	31,546	(45,250)	- Tab 3, Page 5.7
29	Cash Working Capital	14,890	(13,451)	367	(13,084)	(27,974)	- Tab 5, Page 2
30	Other Working Capital	88,705	98,485	0	98,485	9,780	- Tab 5, Page 2
31	Deferred Income Tax, Mid-Year	0	(364)	0	(364)	(364)	
32	Capital Efficiency Mechanism	(7,780)	(1,381)	0	(1,381)	6,399	
33	LILO Benefit	0	(2,265)	0	(2,265)	(2,265)	
34	Utility Rate Base	$2,239,012	$2,272,203	$367	$2,272,570	$33,558	- Tab 2, Page 2

BC GAS UTILITY LTD.

UTILITY RATE BASE
FOR THE YEARS ENDING DECEMBER 31, 2004 AND 2005
($000)

		2004			2005			
Line No.	Rates	2003 Rates	Adjustments	Revised Rates	2004 Rates	Adjustments	Revised Rates	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Plant in Service, Beginning	$2,849,113	$0	$2,849,113	$2,950,816	$0	$2,950,816	
2	CPCNs	9,673	0	9,673	9,436	0	9,436	- Tab 3, Pages 2.2 & 2.4
3								
4	Additions	113,169	0	113,169	104,073	0	104,073	- Tab 3, Pages 2.2 & 2.4
5	Disposals	(21,139)	0	(21,139)	(17,767)	0	(17,767)	- Tab 3, Pages 2.2 & 2.4
6								
7	Plant in Service, Ending	2,950,816	0	2,950,816	3,046,558	0	3,046,558	
8								
9	Add - Intangible Plant	837	0	837	837	0	837	
10								
11		2,951,653	0	2,951,653	3,047,395	0	3,047,395	
12								
13	Contributions In Aid of Construction	(156,440)	0	(156,440)	(160,831)	0	(160,831)	- Tab 3, Page 4.1
14								
15	Less - Accumulated Depreciation	(585,983)	0	(585,983)	(655,161)	0	(655,161)	- Tab 4, Page 2
16								
17								
18	Net Plant in Service, Ending	$2,209,230	$0	$2,209,230	$2,231,403	$0	$2,231,403	
19								
20								
21	Net Plant in Service, Beginning	$2,184,185	$0	$2,184,185	$2,218,666	$0	$2,218,666	- Tab 3, Page 4.4
22								
23								
24	Net Plant in Service, Mid-Year	$2,196,708	$0	$2,196,708	$2,225,035	$0	$2,225,035	
25	Adjustment to 13-Month Average	0	0	0	0	0	0	
26	Construction Advances	(1,000)	0	(1,000)	(1,000)	0	(1,000)	
27	Work in Progress, No AFUDC	4,000	0	4,000	3,600	0	3,600	
28	Unamortized Deferred Charges	4,483	0	4,483	(7,663)	0	(7,663)	- Tab 3, Pages 5.9 & 5.11
29	Cash Working Capital	(13,433)	(25)	(13,458)	(13,134)	278	(12,856)	- Tab 5, Page 2
30	Other Working Capital	102,494	0	102,494	105,023	0	105,023	- Tab 5, Page 2
31	Deferred Income Tax, Mid-Year	(364)	0	(364)	(364)	0	(364)	
32	LILO Benefit	(2,131)	0	(2,131)	(1,997)	0	(1,997)	
33								
34	Utility Rate Base	$2,290,757	($25)	$2,290,732	$2,309,500	$278	$2,309,778	- Tab 2, Page 2.1

BC GAS UTILITY LTD.

UTILITY RATE BASE
FOR THE YEARS ENDING DECEMBER 31, 2006 AND 2007
($000)

Line No.	Rates	2006: 2005 Rates	2006: Adjustments	2006: Revised Rates	2007: 2006 Rates	2007: Adjustments	2007: Revised Rates	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Plant in Service, Beginning	$3,046,558	$0	$3,046,558	$3,123,829	$0	$3,123,829	
2	CPCNs	23,097	0	23,097	69,120	0	69,120	- Tab 3, Pages 2.4 & 2.6
3								
4	Additions	109,078	0	109,078	104,665	0	104,665	- Tab 3, Pages 2.4 & 2.6
5	Disposals	(54,904)	0	(54,904)	(26,138)	0	(26,138)	- Tab 3, Pages 2.4 & 2.6
6								
7	Plant in Service, Ending	3,123,829	0	3,123,829	3,271,476	0	3,271,476	
8								
9	Add - Intangible Plant	837	0	837	837	0	837	
10								
11		3,124,666	0	3,124,666	3,272,313	0	3,272,313	
12								
13	Contributions In Aid of Construction	(165,422)	0	(165,422)	(156,959)	0	(156,959)	- Tab 3, Page 4.2
14								
15	Less - Accumulated Depreciation	(691,047)	0	(691,047)	(768,630)	0	(768,630)	- Tab 4, Page 2
16								
17								
18	Net Plant in Service, Ending	$2,268,197	$0	$2,268,197	$2,346,724	$0	$2,346,724	
19								
20								
21	Net Plant in Service, Beginning	$2,254,500	$0	$2,254,500	$2,337,317	$0	$2,337,317	- Tab 3, Page 4.4
22								
23								
24	Net Plant in Service, Mid-Year	$2,261,349	$0	$2,261,349	$2,342,021	$0	$2,342,021	
25	Adjustment to 13-Month Average	0	0	0	0	0	0	
26	Construction Advances	(1,000)	0	(1,000)	(1,000)	0	(1,000)	
27	Work in Progress, No AFUDC	3,800	0	3,800	3,700	0	3,700	
28	Unamortized Deferred Charges	(15,146)	0	(15,146)	(18,199)	0	(18,199)	- Tab 3, Pages 5.13 & 5.15
29	Cash Working Capital	(13,147)	297	(12,850)	(13,119)	314	(12,805)	- Tab 5, Page 2.1
30	Other Working Capital	107,961	0	107,961	110,476	0	110,476	- Tab 5, Page 2.1
31	Deferred Income Tax, Mid-Year	(364)	0	(364)	(364)	0	(364)	
32	LILO Benefit	(1,863)	0	(1,863)	(1,729)	0	(1,729)	
33								
34	Utility Rate Base	$2,341,590	$297	$2,341,887	$2,421,786	$314	$2,422,100	- Tab 2, Page 2.2

BC GAS UTILITY LTD.

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2003
($000)

Line No.	Particulars	2001	2003 Present Rates	2003 ----Revised Rates----- Revised Revenue	2003 ----Revised Rates----- Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	ENERGY VOLUMES (TJ)						
2	Sales	138,365	126,035	0	126,035	(12,330)	
3	Transportation	155,961	124,369	0	124,369	(31,592)	
4		294,326	250,404	0	250,404	(43,922)	
5							
6	Average Rate per GJ						
7	Sales	$9.113	$9.156		$9.156	$0.043	
8	Transportation	$0.354	$0.480		$0.480	$0.126	
9	Average	$4.472	$4.847		$4.908	$0.436	
10							
11	UTILITY REVENUE						
12	Sales - Present Rates	$1,260,905	$1,154,009	$0	$1,154,009	($106,896)	- Tab 7, Page 1
13	- Increase			14,689	14,689	14,689	
14							
15	Transportation - Present Rates	55,222	59,649	0	59,649	4,427	- Tab 7, Page 1
16	- Increase			676	676	676	
17	**Total**	1,316,127	1,213,658	15,365	1,229,023	(87,104)	- Tab 7, Page 2.1
18							
19	Cost of Gas Sold (Including Gas Lost)	852,158	759,117	0	759,117	(93,041)	
20							
21	**Gross Margin**	463,969	454,541	15,365	469,906	5,937	
22							
23	Operation and Maintenance	132,940	152,013	0	152,013	19,073	- Tab 9, Page 2.1
24	Vehicle / Coastal Facilities Lease	7,130	6,306	0	6,306	(824)	
25	Property and Sundry Taxes	40,924	41,213	0	41,213	289	- Tab 10, Page 2
26	Depreciation and Amortization	70,324	72,651	0	72,651	2,327	- Tab 11, Page 2
27	Other Operating Revenue	(21,691)	(22,737)	0	(22,737)	(1,046)	- Tab 12, Page 2
28		229,627	249,446	0	249,446	19,819	
29	Utility Income Before Income Taxes	234,342	205,095	15,365	220,460	(13,882)	
30							
31	Income Taxes	50,203	34,749	5,602	40,351	(9,852)	
32							
33	**EARNED RETURN**	$184,139	$170,346	$9,763	$180,109	($4,030)	
34							
35	**UTILITY RATE BASE**	$2,239,012	$2,272,203	$367	$2,272,570	$33,558	
36							
37	**RATE OF RETURN ON UTILITY RATE BASE**	8.224%	7.497%		7.926%	-0.30%	

BC GAS UTILITY LTD.

UTILITY INCOME AND EARNED RETURN
FOR THE YEARS ENDING DECEMBER 31, 2004 AND 2005
($000)

Line No.	Particulars (1)	2004: 2003 Rates (2)	2004: ----Revised Rates----- Revised Revenue (3)	2004: ----Revised Rates----- Total (4)	2005: 2004 Rates (5)	2005: ----Revised Rates----- Revised Revenue (6)	2005: ----Revised Rates----- Total (7)	Reference (8)
1	ENERGY VOLUMES (TJ)							
2	Sales	127,222	0	127,222	128,406	0	128,406	
3	Transportation	131,987	0	131,987	135,103	0	135,103	
4		259,209	0	259,209	263,509	0	263,509	
5								
6	Average Rate per GJ							
7	Sales	$9.275	$0.000	$9.349	$9.350	$0.000	$9.483	
8	Transportation	$0.457	$0.000	$0.465	$0.456	$0.000	$0.470	
9	Average	$4.785	$0.000	$4.825	$4.790	$0.000	$4.862	
10								
11	UTILITY REVENUE							
12	Sales - Present Rates	$1,179,961	$0	$1,179,961	$1,200,590	$0	$1,200,590	- Tab 7, Page 1
13	- Increase	0	9,405	9,405	0	17,041	17,041	
14								
15	Transportation - Present Rates	60,346	0	60,346	61,601	0	61,601	- Tab 7, Page 1
16	- Increase		1,075	1,075		1,935	1,935	
17	Total	1,240,307	10,480	1,250,787	1,262,191	18,976	1,281,167	- Tab 7, Pages 2.3 & 2.5
18								
19	Cost of Gas Sold (Including Gas Lost)	766,309	0	766,309	773,414	0	773,414	
20								
21	Gross Margin	473,998	10,480	484,478	488,777	18,976	507,753	
22								
23	Operation and Maintenance	158,470	0	158,470	173,592	0	173,592	- Tab 9, Page 2.1
24	Vehicle / Coastal Facilities Lease	6,394	0	6,394	6,344	0	6,344	
25	Property and Sundry Taxes	41,213	0	41,213	41,213	0	41,213	- Tab 10, Page 2
26	Depreciation and Amortization	79,547	0	79,547	81,131	0	81,131	- Tab 11. Page 2
27	Other Operating Revenue	(22,575)	0	(22,575)	(22,771)	0	(22,771)	- Tab 12, Page 2
28		263,049	0	263,049	279,509	0	279,509	
29	Utility Income Before Income Taxes	210,949	10,480	221,429	209,268	18,976	228,244	
30								
31	Income Taxes	37,302	3,617	40,919	40,520	6,545	47,065	
32								
33	EARNED RETURN	$173,647	$6,863	$180,510	$168,748	$12,431	$181,179	
34								
35	UTILITY RATE BASE	$2,290,757	($25)	$2,290,732	$2,309,500	$278	$2,309,778	
36								
37	RATE OF RETURN ON UTILITY RATE BASE	7.580%	0.000%	7.880%	7.310%	0.000%	7.844%	

BC GAS UTILITY LTD.

UTILITY INCOME AND EARNED RETURN
FOR THE YEARS ENDING DECEMBER 31, 2006 AND 2007
($000)

		2006			2007			
			----Revised Rates-----			----Revised Rates-----		
Line No.	Particulars	2005 Rates	Revised Revenue	Total	2006 Rates	Revised Revenue	Total	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	ENERGY VOLUMES (TJ)							
2	Sales	129,599	0	129,599	130,801	0	130,801	
3	Transportation	143,684	0	143,684	129,215	0	129,215	
4		273,283	0	273,283	260,016	0	260,016	
5								
6	Average Rate per GJ							
7	Sales	$9.484	$0.000	$9.581	$9.583	$0.000	$9.646	
8	Transportation	$0.444	$0.000	$0.453	$0.505	$0.000	$0.512	
9	Average	$4.731	$0.000	$4.782	$5.072	$0.000	$5.107	
10								
11	UTILITY REVENUE							
12	Sales - Present Rates	$1,229,107	$0	$1,229,107	$1,253,456	$0	$1,253,456	- Tab 7, Page 1.1
13	- Increase	0	12,614	12,614	0	8,202	8,202	
14								
15	Transportation - Present Rates	63,725	0	63,725	65,303	0	65,303	- Tab 7, Page 1.1
16	- Increase		1,426	1,426		919	919	
17	Total	1,292,832	14,040	1,306,872	1,318,759	9,121	1,327,880	- Tab 7, Pages 2.7 & 2.9
18								
19	Cost of Gas Sold (Including Gas Lost)	780,607	0	780,607	787,685	0	787,685	
20								
21	Gross Margin	512,225	14,040	526,265	531,074	9,121	540,195	
22								
23	Operation and Maintenance	181,702	0	181,702	189,447	0	189,447	- Tab 9, Page 2.1
24	Vehicle / Coastal Facilities Lease	6,332	0	6,332	6,037	0	6,037	
25	Property and Sundry Taxes	41,213	0	41,213	41,213	0	41,213	- Tab 10, Page 2
26	Depreciation and Amortization	85,995	0	85,995	85,687	0	85,687	- Tab 11, Page 2
27	Other Operating Revenue	(22,901)	0	(22,901)	(23,013)	0	(23,013)	- Tab 12, Page 2
28		292,341	0	292,341	299,371	0	299,371	
29	Utility Income Before Income Taxes	219,884	14,040	233,924	231,703	9,121	240,824	
30								
31	Income Taxes	43,890	4,931	48,821	46,359	3,143	49,502	
32								
33	EARNED RETURN	$175,994	$9,109	$185,103	$185,344	$5,978	$191,322	
34								
35	UTILITY RATE BASE	$2,341,590	$297	$2,341,887	$2,421,786	$314	$2,422,100	
36								
37	RATE OF RETURN ON UTILITY RATE BASE	7.520%	0.000%	7.904%	7.650%	0.000%	7.899%	

BC GAS UTILITY LTD.

INCOME TAXES / REVENUE DEFICIENCY
FOR THE YEAR ENDING DECEMBER 31, 2003
($000)

Line No.	Particulars	2001	2003 Present Rates	2003 ----Revised Rates----- Revised Revenue	2003 ----Revised Rates----- Total	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	CALCULATION OF INCOME TAXES						
2	Earned Return	$184,139	$170,346	$9,763	$180,109	($4,030)	- Tab 2, Page 2
3	Deduct - Interest on Debt	(115,802)	(111,633)	(18)	(111,651)	4,151	- Tab 13, Page 3
4	Add- Non-Tax Ded. Expense (Net)	2,836	1,766	0	1,766	(1,070)	- Tab 13, Page 4
5							
6	Accounting Income After Tax	71,173	60,479	9,745	70,224	(949)	
7	Add (Deduct) - Timing Differences	(18,066)	(14,219)	0	(14,219)	3,847	- Tab 13, Page 4
8	Add - Large Corporation Tax	4,106	4,273	(171)	4,102	(4)	- Tab 13, Page 6
9							
10	Taxable Income After Tax	$57,213	$50,533	$9,574	$60,107	$2,894	
11							
12	Income Tax Rate (Current Tax)	44.620%	37.620%	37.620%	37.620%	-7.000%	
13	1 - Current Income Tax Rate	55.380%	62.380%	62.380%	62.380%	7.000%	
14							
15	Taxable Income (L10 : L13)	$103,310	$81,008	$15,347	$96,356	($6,954)	
16							
17	Income Tax - Current (L12 x L15)	$46,097	$30,475	$5,774	$36,249	($9,848)	
18							
19	- Large Corporation Tax	4,106	4,273	(171)	4,102	(4)	- Tab 13, Page 6
20							
21	Total	$50,203	$34,748	$5,603	$40,351	($9,852)	- Tab 2, Page 2
22							
23							
24	REVENUE DEFICIENCY						
25	Earned Return	$184,139		$9,763	$180,109	($4,030)	
26	Add - Income Taxes	50,203		5,602	40,351	(9,852)	- Tab 13, Page 2
27	Deduct - Utility Income Before Taxes,						
28	Present Rates	(182,057)		0	(205,095)	(23,038)	
29	Corporate Capital Tax	4		0	0	(4)	- Tab 10, Page 2
30							
31	Deficiency After Corporate Capital Tax	$52,289		$15,365	$15,365	($36,924)	

BC GAS UTILITY LTD.

INCOME TAXES / REVENUE DEFICIENCY
FOR THE YEARS ENDING DECEMBER 31, 2004 AND 2005
($000)

Line No.	Particulars	2004 2003 Rates	2004 ----Revised Rates----- Revised Revenue	2004 ----Revised Rates----- Total	2005 2004 Rates	2005 ----Revised Rates----- Revised Revenue	2005 ----Revised Rates----- Total	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	CALCULATION OF INCOME TAXES							
2	Earned Return	$173,647	$6,863	$180,510	$168,748	$12,431	$181,179	- Tab 2, Page 2.1
3	Deduct - Interest on Debt	(111,489)	2	(111,487)	(111,574)	(8)	(111,582)	- Tab 13, Page 3
4	Add- Non-Tax Ded. Expense (Net)	1,906	0	1,906	1,450	0	1,450	- Tab 13, Page 4
5								
6	Accounting Income After Tax	64,064	6,865	70,929	58,624	12,423	71,047	
7	Add (Deduct) - Timing Differences	(8,333)	0	(8,333)	3,135	0	3,135	- Tab 13, Page 4
8	Add - Large Corporation Tax	4,164	(117)	4,047	4,088	(211)	3,877	- Tab 13, Page 6
9								
10	Taxable Income After Tax	$59,895	$6,748	$66,643	$65,847	$12,212	$78,059	
11								
12	Income Tax Rate (Current Tax)	35.620%	35.620%	35.620%	35.620%	35.620%	35.620%	
13	1 - Current Income Tax Rate	64.380%	64.380%	64.380%	64.380%	64.380%	64.380%	
14								
15	Taxable Income (L10 : L13)	$93,033	$10,482	$103,515	$102,279	$18,968	$121,247	
16								
17	Income Tax - Current (L12 x L15)	$33,138	$3,734	$36,872	$36,432	$6,756	$43,188	
18	- Deferred Income Tax							
19	- Large Corporation Tax	4,164	(117)	4,047	4,088	(211)	3,877	- Tab 13, Page 6
20								
21	Total	$37,302	$3,617	$40,919	$40,520	$6,545	$47,065	- Tab 2, Page 2.1
22								
23								
24	REVENUE DEFICIENCY							
25	Earned Return		$6,863	$180,510		$12,431	$181,179	
26	Add - Income Taxes		3,617	40,919		6,545	47,065	- Tab 13, Page 2
27	Deduct - Utility Income Before Taxes,							
28	Present Rates		0	(210,949)		0	(209,268)	
29	Corporate Capital Tax		0	0		0	0	- Tab 10, Page 2
30								
31	Deficiency After Corporate Capital Tax		$10,480	$10,480		$18,976	$18,976	

INCOME TAXES / REVENUE DEFICIENCY
FOR THE YEARS ENDING DECEMBER 31, 2006 AND 2007
($000)

Line No.	Particulars	2006 2005 Rates	2006 ----Revised Rates----- Revised Revenue	2006 ----Revised Rates----- Total	2007 2006 Rates	2007 ----Revised Rates----- Revised Revenue	2007 ----Revised Rates----- Total	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	CALCULATION OF INCOME TAXES							
2	Earned Return	$175,994	$9,109	$185,103	$185,344	$5,978	$191,322	- Tab 2, Page 2.2
3	Deduct - Interest on Debt	(114,530)	(13)	(114,543)	(118,314)	(9)	(118,323)	- Tab 13, Page 3
4	Add- Non-Tax Ded. Expense (Net)	1,317	0	1,317	1,443	0	1,443	- Tab 13, Page 4
5								
6	Accounting Income After Tax	62,781	9,096	71,877	68,473	5,969	74,442	- Tab 13, Page 4
7	Add (Deduct) - Timing Differences	5,166	0	5,166	3,648	0	3,648	- Tab 13, Page 6.1
8	Add - Large Corporation Tax	4,054	102	4,156	4,156	(102)	4,054	
9								
10	Taxable Income After Tax	$72,001	$9,198	$81,199	$76,277	$5,867	$82,144	
11								
12	Income Tax Rate (Current Tax)	35.620%	35.620%	35.620%	35.620%	35.620%	35.620%	
13	1 - Current Income Tax Rate	64.380%	64.380%	64.380%	64.380%	64.380%	64.380%	
14								
15	Taxable Income (L10 : L13)	$111,837	$14,288	$126,125	$118,480	$9,112	$127,592	
16								
17	Income Tax - Current (L12 x L15)	$39,836	$5,089	$44,926	$42,203	$3,246	$45,448	
18	- Deferred Income Tax							
19	- Large Corporation Tax	4,054	(159)	3,895	4,156	(102)	4,054	- Tab 13, Page 6.1
20								
21	Total	$43,890	$4,930	$48,821	$46,359	$3,144	$49,502	- Tab 2, Page 2.2
22								
23								
24	REVENUE DEFICIENCY							
25	Earned Return		$9,109	$185,103		$5,978	$191,322	
26	Add - Income Taxes		4,931	48,821		3,143	49,502	- Tab 13, Page 2.1
27	Deduct - Utility Income Before Taxes,							
28	Present Rates		0	(219,884)		0	(231,703)	
29	Corporate Capital Tax		0	0		0	0	- Tab 10, Page 2
30								
31	Deficiency After Corporate Capital Tax		$14,040	$14,040		$9,121	$9,121	

BC GAS UTILITY LTD.
RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2003
($000)

Line No.	Particulars	Reference	-------- Capitalization --------	Amount	%	Embedded Cost	Cost Component	Earned Return
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2003 PRESENT RATES							
2	Long-Term Debt			$1,343,432	59.12%	7.643%	4.519%	
3	Unfunded Debt			178,944	7.88%	5.000%	0.394%	
4	Preference Shares			0	0.00%	0.000%	0.000%	
5	Common Equity			749,827	33.00%	7.830%	2.584%	
6								
7				$2,272,203	100.00%		7.497%	
8								
9	2003 REVISED RATES							
10	Long-Term Debt			$1,343,432	59.12%	7.643%	4.519%	$102,679
11	Unfunded Debt		$178,944					
12	Adjustment, Revised Rates		246	179,190	7.88%	5.000%	0.394%	8,960
13	Preference Shares			0	0.00%	0.000%	0.000%	0
14	Common Equity			749,948	33.00%	9.130%	3.013%	68,470
15								
16				$2,272,570	100.00%		7.926%	$180,108
17								
18	2001							
19	Long-Term Debt			$1,193,475	53.30%	8.032%	4.280%	$95,860
20	Unfunded Debt		$211,701					
21	Adjustment, Revised Rates		94,962	306,663	13.70%	6.500%	0.890%	19,933
22	Preference Shares			0	0.00%	0.000%	0.000%	0
23	Common Equity			738,874	33.00%	9.250%	3.050%	68,346
24								
25				$2,239,012	100.00%		8.2200%	$184,139
26								
27	2003 CHANGE FROM 2001							
28	Long-Term Debt			$149,957	5.82%	-0.389%	0.239%	$6,819
29	Unfunded Debt		($32,757)					
30	Adjustment, Revised Rates		(94,716)	(127,473)	-5.82%	-1.500%	-0.496%	(10,974)
31	Preference Shares			0	0.00%	0.000%	0.000%	0
32	Common Equity			11,074	0.00%	-0.120%	-0.037%	124
33								
34				$33,558	100.00%		-0.294%	($4,031)

BC GAS UTILITY LTD.
RETURN ON CAPITAL
FOR THE YEARS ENDING DECEMBER 31, 2004 AND 2005
($000)

Line No.	Particulars	Reference	-------- Capitalization --------	Amount	%	Embedded Cost	Cost Component	Earned Return
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2004 AT 2003 RATES							
2	Long-Term Debt			$1,333,811	58.23%	7.605%	4.519%	
3	Unfunded Debt			200,996	8.77%	5.000%	0.394%	
4	Preference Shares			0	0.00%	0.000%	0.000%	
5	Common Equity			755,950	33.00%	8.221%	2.584%	
6								
7				$2,290,757	100.00%		7.497%	
8								
9	2004 REVISED RATES							
10	Long-Term Debt			$1,333,811	58.23%	7.605%	4.428%	$101,436
11	Unfunded Debt		$200,996					
12	Adjustment, Revised Rates		(17)	200,979	8.77%	5.000%	0.439%	10,049
13	Preference Shares			0	0.00%	0.000%	0.000%	0
14	Common Equity			755,942	33.00%	9.130%	3.013%	69,018
15								
16				$2,290,732	100.00%		7.880%	$180,503
17								
18	2005 AT 2004 RATES							
19	Long-Term Debt			$1,340,937	58.06%	7.551%	4.428%	
20	Unfunded Debt			206,428	8.94%	5.000%	0.439%	
21	Preference Shares			0	0.00%	0.000%	0.000%	
22	Common Equity			762,135	33.00%	7.512%	2.713%	
23								
24				$2,309,500	100.00%		7.580%	
25								
26	2005 REVISED RATES							
27	Long-Term Debt			$1,340,937	58.05%	7.551%	4.383%	$101,254
28	Unfunded Debt		$206,428					
29	Adjustment, Revised Rates		186	206,614	8.95%	5.000%	0.448%	10,331
30	Preference Shares			0	0.00%	0.000%	0.000%	0
31	Common Equity			762,227	33.00%	9.130%	3.013%	69,591
32								
33				$2,309,778	100.00%		7.844%	$181,176

BC GAS UTILITY LTD.
RETURN ON CAPITAL
FOR THE YEARS ENDING DECEMBER 31, 2006 AND 2007
($000)

Line No.	Particulars	Reference	-------- Capitalization --------	Amount	%	Embedded Cost	Component	Earned Return
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2006 AT 2005 RATES							
2	Long-Term Debt			$1,403,665	59.94%	7.571%	4.538%	
3	Unfunded Debt			165,200	7.06%	5.000%	0.353%	
4	Preference Shares			0	0.00%	0.000%	0.000%	
5	Common Equity			772,725	33.00%	9.788%	3.230%	
6								
7				$2,341,590	100.00%		8.121%	
8								
9	2006 REVISED RATES							
10	Long-Term Debt			$1,403,665	59.94%	7.571%	4.538%	$106,271
11	Unfunded Debt		$165,200					
12	Adjustment, Revised Rates		199	165,399	7.06%	5.000%	0.353%	8,270
13	Preference Shares			0	0.00%	0.000%	0.000%	0
14	Common Equity			772,823	33.00%	9.130%	3.013%	70,559
15								
16				$2,341,887	100.00%		7.904%	$185,100
17								
18	2007 AT 2006 RATES							
19	Long-Term Debt			$1,452,962	60.00%	7.559%	4.535%	
20	Unfunded Debt			169,635	7.00%	5.000%	0.350%	
21	Preference Shares			0	0.00%	0.000%	0.000%	
22	Common Equity			799,189	33.00%	8.379%	2.765%	
23								
24				$2,421,786	100.00%		7.650%	
25								
26	2007 REVISED RATES							
27	Long-Term Debt			$1,452,962	59.99%	7.559%	4.535%	$109,829
28	Unfunded Debt		$169,635					
29	Adjustment, Revised Rates		210	169,845	7.01%	5.000%	0.351%	8,492
30	Preference Shares			0	0.00%	0.000%	0.000%	0
31	Common Equity			799,293	33.00%	9.130%	3.013%	72,975
32								
33				$2,422,100	100.00%		7.899%	$191,297

BC GAS UTILITY LTD.
UTILITY RATE BASE
FOR THE YEARS ENDING DECEMBER 31, 2003 TO 2007

BC GAS UTILITY LTD.

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2003
($000)

Line No.	Particulars	2001	2003 Present Rates	2003 Adjustments	2003 Revised Rates	Change	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Plant in Service, Beginning	$2,110,015	$2,711,233	$0	$2,711,233	$601,218	
2	CPCNs	434,195	31,845	0	31,845	(402,350)	- Tab 3, Page 2.2
3							
4	Additions	107,092	119,102	0	119,102	12,010	- Tab 3, Page 2.2
5	Disposals	(15,980)	(13,067)	0	(13,067)	2,913	- Tab 3, Page 2.2
6							
7	Plant in Service, Ending	2,635,322	2,849,113	0	2,849,113	213,791	
8							
9	Add - Intangible Plant	837	837	0	837	0	
10							
11		2,636,159	2,849,950	0	2,849,950	213,791	
12							
13	Contributions In Aid of Construction	(133,691)	(148,436)	0	(148,436)	(14,745)	- Tab 3, Page 4.1
14							
15	Less - Accumulated Depreciation	(428,130)	(527,002)	0	(527,002)	(98,872)	- Tab 4, Page 2
16							
17							
18	Net Plant in Service, Ending	$2,074,338	$2,174,512	$0	$2,174,512	$100,174	
19							
20							
21	Net Plant in Service, Beginning	$2,058,968	$2,138,353	$0	$2,138,353	$79,385	- Tab 3, Page 4.4
22							
23							
24	Net Plant in Service, Mid-Year	$2,066,653	$2,156,433	$0	$2,156,433	$89,780	
25	Adjustment to 13-Month Average	0	0	0	0	0	
26	Construction Advances	(4,000)	(1,000)	0	(1,000)	3,000	
27	Work in Progress, No AFUDC	3,748	4,200	0	4,200	452	
28	Unamortized Deferred Charges	76,796	31,546	0	31,546	(45,250)	- Tab 3, Page 5.7
29	Cash Working Capital	14,890	(13,451)	367	(13,084)	(27,974)	- Tab 5, Page 2
30	Other Working Capital	88,705	98,485	0	98,485	9,780	- Tab 5, Page 2
31	Deferred Income Tax, Mid-Year	0	(364)	0	(364)	(364)	
32	Capital Efficiency Mechanism	(7,780)	(1,381)	0	(1,381)	6,399	
33	LILO Benefit	0	(2,265)	0	(2,265)	(2,265)	
34	Utility Rate Base	$2,239,012	$2,272,203	$367	$2,272,570	$33,558	- Tab 2, Page 2

BC GAS UTILITY LTD.

UTILITY RATE BASE
FOR THE YEARS ENDING DECEMBER 31, 2004 AND 2005
($000)

		2004			2005			
Line No.	Particulars	2003 Rates	Adjustments	Revised Rates	2004 Rates	Adjustments	Revised Rates	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Plant in Service, Beginning	$2,849,113	$0	$2,849,113	$2,950,816	$0	$2,950,816	
2	CPCNs	9,673	0	9,673	9,436	0	9,436	- Tab 3, Pages 2.2 & 2.4
3								
4	Additions	113,169	0	113,169	104,073	0	104,073	- Tab 3, Pages 2.2 & 2.4
5	Disposals	(21,139)	0	(21,139)	(17,767)	0	(17,767)	- Tab 3, Pages 2.2 & 2.4
6								
7	Plant in Service, Ending	2,950,816	0	2,950,816	3,046,558	0	3,046,558	
8								
9	Add - Intangible Plant	837	0	837	837	0	837	
10								
11		2,951,653	0	2,951,653	3,047,395	0	3,047,395	
12								
13	Contributions In Aid of Construction	(156,440)	0	(156,440)	(160,831)	0	(160,831)	- Tab 3, Page 4.1
14								
15	Less - Accumulated Depreciation	(585,983)	0	(585,983)	(655,161)	0	(655,161)	- Tab 4, Page 2
16								
17								
18	Net Plant in Service, Ending	$2,209,230	$0	$2,209,230	$2,231,403	$0	$2,231,403	
19								
20								
21	Net Plant in Service, Beginning	$2,184,185	$0	$2,184,185	$2,218,666	$0	$2,218,666	- Tab 3, Page 4.4
22								
23								
24	Net Plant in Service, Mid-Year	$2,196,708	$0	$2,196,708	$2,225,035	$0	$2,225,035	
25	Adjustment to 13-Month Average	0	0	0	0	0	0	
26	Construction Advances	(1,000)	0	(1,000)	(1,000)	0	(1,000)	
27	Work in Progress, No AFUDC	4,000	0	4,000	3,600	0	3,600	
28	Unamortized Deferred Charges	4,483	0	4,483	(7,663)	0	(7,663)	- Tab 3, Pages 5.9 & 5.11
29	Cash Working Capital	(13,433)	(25)	(13,458)	(13,134)	278	(12,856)	- Tab 5, Page 2
30	Other Working Capital	102,494	0	102,494	105,023	0	105,023	- Tab 5, Page 2
31	Deferred Income Tax, Mid-Year	(364)	0	(364)	(364)	0	(364)	
32	LILO Benefit	(2,131)	0	(2,131)	(1,997)	0	(1,997)	
33								
34	Utility Rate Base	$2,290,757	($25)	$2,290,732	$2,309,500	$278	$2,309,778	- Tab 2, Page 2.1

BC GAS UTILITY LTD.

UTILITY RATE BASE
FOR THE YEARS ENDING DECEMBER 31, 2006 AND 2007
($000)

Line No.	Particulars	2006: 2005 Rates	2006: Adjustments	2006: Revised Rates	2007: 2006 Rates	2007: Adjustments	2007: Revised Rates	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Plant in Service, Beginning	$3,046,558	$0	$3,046,558	$3,123,829	$0	$3,123,829	
2	CPCNs	23,097	0	23,097	69,120	0	69,120	- Tab 3, Pages 2.4 & 2.6
3								
4	Additions	109,078	0	109,078	104,665	0	104,665	- Tab 3, Pages 2.4 & 2.6
5	Disposals	(54,904)	0	(54,904)	(26,138)	0	(26,138)	- Tab 3, Pages 2.4 & 2.6
6								
7	Plant in Service, Ending	3,123,829	0	3,123,829	3,271,476	0	3,271,476	
8								
9	Add - Intangible Plant	837	0	837	837	0	837	
10								
11		3,124,666	0	3,124,666	3,272,313	0	3,272,313	
12								
13	Contributions In Aid of Construction	(165,422)	0	(165,422)	(156,959)	0	(156,959)	- Tab 3, Page 4.2
14								
15	Less - Accumulated Depreciation	(691,047)	0	(691,047)	(768,630)	0	(768,630)	- Tab 4, Page 2
16								
17								
18	Net Plant in Service, Ending	$2,268,197	$0	$2,268,197	$2,346,724	$0	$2,346,724	
19								
20								
21	Net Plant in Service, Beginning	$2,254,500	$0	$2,254,500	$2,337,317	$0	$2,337,317	- Tab 3, Page 4.4
22								
23								
24	Net Plant in Service, Mid-Year	$2,261,349	$0	$2,261,349	$2,342,021	$0	$2,342,021	
25	Adjustment to 13-Month Average	0	0	0	0	0	0	
26	Construction Advances	(1,000)	0	(1,000)	(1,000)	0	(1,000)	
27	Work in Progress, No AFUDC	3,800	0	3,800	3,700	0	3,700	
28	Unamortized Deferred Charges	(15,146)	0	(15,146)	(18,199)	0	(18,199)	- Tab 3, Pages 5.13 & 5.15
29	Cash Working Capital	(13,147)	297	(12,850)	(13,119)	314	(12,805)	- Tab 5, Page 2
30	Other Working Capital	107,961	0	107,961	110,476	0	110,476	- Tab 5, Page 2
31	Deferred Income Tax, Mid-Year	(364)	0	(364)	(364)	0	(364)	
32	LILO Benefit	(1,863)	0	(1,863)	(1,729)	0	(1,729)	
33								
34	Utility Rate Base	$2,341,590	$297	$2,341,887	$2,421,786	$314	$2,422,100	- Tab 2, Page 2.2

BC GAS UTILITY LTD.
GAS PLANT IN SERVICE
FOR THE YEARS ENDING DECEMBER 31, 2003 TO 2007

The Gas Plant In Service details by account for the forecast years 2003 to 2007 are shown on pages 2.1 to 2.6.

The forecast 2003 to 2007 Capital Expenditures and Plant Additions are shown on page 3.

The Net Plant In Service reconciliation from the year-end December 31st balance to the first-of-year January 1st balance is shown on page 4.4. CPCN expenditures put in-service for the year (but still classified as work-in-progress) are added to Plant (Rate Base), on January 1st of the following year.

BC GAS UTILITY LTD.
GAS PLANT IN SERVICE
FOR THE YEARS ENDING DECEMBER 31, 2003 AND 2004
($000)

Line No.	Particulars	Balance 12/31/2002	CPCN'S	2003 Additions	Retirements	Balance 12/31/2003	CPCN'S	2004 Additions	Retirements	Transfers/ Recovery	Balance 12/31/2004
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	401 Franchise Consents	$99	$0	$0	$0	$99	$0	$0	$0	$0	$99
2	402 Other Intangible Plant	148	0	0	0	148	0	0	0	0	148
3	TOTAL INTANGIBLE PLANT	247	0	0	0	247	0	0	0	0	247
4											
5	430 Manufact'd Gas - Land	31	0	0	0	31	0	0	0	0	31
6	432 Manufact'd Gas - Struct. & Improvements	413	0	0	0	413	0	0	0	0	413
7	433 Manufacturing Equipment	269	0	0	0	269	0	0	0	0	269
8	434 Gas Holders - Manufacturing	353	0	0	0	353	0	0	0	0	353
9	436 Compressed Equipment	53	0	0	0	53	0	0	0	0	53
10	437 Measuring and Regulating Equipment	295	0	0	0	295	0	0	0	0	295
11	440/441 Land in Fee Simple and Land Rights	915	0	0	0	915	0	0	0	0	915
12	442 Structures and Improvements	4,264	0	83	0	4,347	0	0	0	0	4,347
13	443 Gas Holders - Storage	12,279	0	1,835	0	14,114	0	1,944	0	0	16,058
14	446 Compressor Equipment	0	0	0	0	0	0	0	0	0	0
15	447 Measuring and Regulating Equipment	0	0	0	0	0	0	0	0	0	0
16	448 Purification Equipment	0	0	0	0	0	0	0	0	0	0
17	449 Local Storage Equipment	16,447	0	6	0	16,453	0	0	0	0	16,453
18	**TOTAL MANUFACTURED GAS / LOCAL STORAGE**	35,319	0	1,924	0	37,243	0	1,944	0	0	39,187
19											
20	460 Land in Fee Simple	22,354	0	0	0	22,354	0	0	0	0	22,354
21	461 Land Rights	25,969	0	1,314	0	27,283	0	1,537	0	0	28,820
22	462 Compressor Structures	13,088	140	279	0	13,507	0	284	0	0	13,791
23	463 Measuring Structures	3,048	0	0	0	3,048	0	0	0	0	3,048
24	464 Other Structures and Improvements	4,282	0	0	0	4,282	0	0	0	0	4,282
25	465 Mains	643,371	16,035	5,173	(742)	663,837	9,673	3,190	(631)	0	676,069
26	466 Compressor Equipment	96,697	8,551	45	0	105,293	0	36	0	0	105,329
27	467 Measuring and Regulating Equipment	25,760	0	3,876	0	29,636	0	1,218	0	0	30,854
28	468 Communication Structures and Equipment	1,300	0	483	0	1,783	0	492	0	0	2,275
29	469 Other Transmission Equipment	0	0	0	0	0	0	0	0	0	0
30	**TOTAL TRANSMISSION PLANT**	835,869	24,726	11,170	(742)	871,023	9,673	6,757	(631)	0	886,822
31											
32	470 Land	749	0	0	0	749	0	0	0	0	749
33	471 Land Rights	558	0	0	0	558	0	0	0	0	558
34	472 Structures and Improvements	5,956	0	261	0	6,217	0	203	0	0	6,420
35	473 Services	451,937	0	13,473	(2,021)	463,389	0	13,037	(1,956)	0	474,470
36	474 House Regulators and Meter Installations	124,686	0	6,341	(317)	130,710	0	6,443	(322)	0	136,831
37	475 Mains	604,538	0	20,784	(2,078)	623,244	0	18,403	(1,840)	0	639,807
38	476 Compressor Equipment										
39											
40	-All Other	229	0	0	0	229	0	0	0	0	229
41	477 Measuring and Regulating Equipment	51,530	2	6,603	(325)	57,810	0	6,306	(315)	0	63,801
42	478 Meters	149,536	0	10,512	(526)	159,522	0	10,646	(532)	0	169,636
43	479 Other Distribution Equipment	500	0	0	0	500	0	0	0	0	500
44	**TOTAL DISTRIBUTION PLANT**	1,390,219	2	57,974	(5,267)	1,442,928	0	55,038	(4,965)	0	1,493,001

BC GAS UTILITY LTD.

GAS PLANT IN SERVICE
FOR THE YEARS ENDING DECEMBER 31, 2003 AND 2004
($000)

Line No.	Particulars	Balance 12/31/2002	CPCN'S	2003 Additions	Retirements	Balance 12/31/2003	CPCN'S	2004 Additions	Retirements	Transfers/ Recovery	Balance 12/31/2004
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	480 Land	$6,531	$0	$20	$0	$6,551	$0	$21	$0	$0	$6,572
2	481 Land Rights	0	0	0	0	0	0	0	0	0	0
3	482 Structures and Improvements										
4											
5	-All Other	39,632	0	606	0	40,238	0	622	0	0	40,860
6	483 Office Furniture and Equipment										
7	-Fraser Valley / Lochburn / LNG	22,170	0	459	(12)	22,617	0	488	(20)	0	23,085
8	-Computers - Hardware	22,690	(17)	6,319	(4,708)	24,284	0	4,233	(6,459)	0	22,058
9	-Computer Software - Non-Infrastructure	39,227	0	850	(1,256)	38,821	0	900	(5,734)	0	33,987
10	-Computer Software - Infrastructure/Custom	78,978	7,133	10,807	(589)	96,329	0	12,863	(1,871)	0	107,321
11											
12											
13	484 Transportation Equipment	409	0	41	(31)	419	0	47	(261)	0	205
14											
15	485 Heavy Work Equipment	12	0	0	0	12	0	0	(4)	0	8
16	486 Tools and Work Equipment	23,528	0	2,084	(195)	25,417	0	2,136	(217)	0	27,336
17	487 Equipment on Customer's Premises	1,644	0	0	0	1,644	0	0	0	0	1,644
18	488 Communication Equipment	14,793	1	969	(267)	15,496	0	1,049	(977)	0	15,568
19	489 Other General Equipment										
20	-Stores Material, Capital	0	0	0	0	0	0	0	0	0	0
21	-All Other	0	0	0	0	0	0	0	0	0	0
22											
23	**TOTAL GENERAL EQUIPMENT**	249,614	7,117	22,155	(7,058)	271,828	0	22,359	(15,543)	0	278,644
24											
25	492 Gas Plant Held for Future Use	0	0	0	0	0	0	0	0	0	0
26	496 Unclassified Plant	0	0	0	0	0	0	0	0	0	0
27	497 Allowance for Funds Used										
28	During Construction	0	0	0	0	0	0	0	0	0	0
29	498 Overhead Charged To Construction	199,965	0	25,879	0	225,844	0	27,071	0	0	252,915
30	499 Plant Suspense - Overheads	0	0	0	0	0	0	0	0	0	0
31											
32	**TOTAL UNCLASSIFIED PLANT**	199,965	0	25,879	0	225,844	0	27,071	0	0	252,915
33											
34	**TOTAL CAPITAL**	$2,711,233	$31,845	$119,102	($13,067)	$2,849,113	$9,673	$113,169	($21,139)	$0	$2,950,816

BC GAS UTILITY LTD.

GAS PLANT IN SERVICE
FOR THE YEARS ENDING DECEMBER 31, 2005 AND 2006
($000)

Line No.	Particulars	Balance 12/31/2004	CPCN'S	2005 Additions	Retirements	Transfers/ Recovery	Balance 12/31/2005	CPCN'S	2006 Additions	Retirements	Transfers/ Recovery	Balance 12/31/2006
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1	401 Franchise Consents	$99	$0	$0	$0	$0	$99	$0	$0	$0	$0	$99
2	402 Other Intangible Plant	148	0	0	0	0	148	0	0	0	0	148
3	TOTAL INTANGIBLE PLANT	247	0	0	0	0	247	0	0	0	0	247
4												
5	430 Manufact'd Gas - Land	31	0	0	0	0	31	0	0	0	0	31
6	432 Manufact'd Gas - Struct. & Improvements	413	0	0	0	0	413	0	0	0	0	413
7	433 Manufacturing Equipment	269	0	0	0	0	269	0	0	0	0	269
8	434 Gas Holders - Manufacturing	353	0	0	0	0	353	0	0	0	0	353
9	436 Compressed Equipment	53	0	0	0	0	53	0	0	0	0	53
10	437 Measuring and Regulating Equipment	295	0	0	0	0	295	0	0	0	0	295
11	440/441 Land in Fee Simple and Land Rights	915	0	0	0	0	915	0	0	0	0	915
12	442 Structures and Improvements	4,347	0	0	0	0	4,347	0	0	0	0	4,347
13	443 Gas Holders - Storage	16,058	0	2,529	0	0	18,587	0	394	0	0	18,981
14	446 Compressor Equipment	0	0	0	0	0	0	0	0	0	0	0
15	447 Measuring and Regulating Equipment	0	0	0	0	0	0	0	0	0	0	0
16	448 Purification Equipment	0	0	0	0	0	0	0	0	0	0	0
17	449 Local Storage Equipment	16,453	0	0	0	0	16,453	0	0	0	0	16,453
18	TOTAL MANUFACTURED GAS / LOCAL STORAGE	39,187	0	2,529	0	0	41,716	0	394	0	0	42,110
19												
20	460 Land in Fee Simple	22,354	0	0	0	0	22,354	0	0	0	0	22,354
21	461 Land Rights	28,820	0	507	0	0	29,327	0	237	0	0	29,564
22	462 Compressor Structures	13,791	0	289	0	0	14,080	0	295	0	0	14,375
23	463 Measuring Structures	3,048	0	0	0	0	3,048	0	0	0	0	3,048
24	464 Other Structures and Improvements	4,282	0	0	0	0	4,282	0	0	0	0	4,282
25	465 Mains	676,069	9,436	4,343	(1,372)	0	688,476	23,097	3,905	(2,658)	0	712,820
26	466 Compressor Equipment	105,329	0	39	0	0	105,368	0	40	0	0	105,408
27	467 Measuring and Regulating Equipment	30,854	0	682	0	0	31,536	0	685	0	0	32,221
28	468 Communication Structures and Equipment	2,275	0	502	0	0	2,777	0	512	0	0	3,289
29	469 Other Transmission Equipment	0	0	0	0	0	0	0	0	0	0	0
30	TOTAL TRANSMISSION PLANT	886,822	9,436	6,362	(1,372)	0	901,248	23,097	5,674	(2,658)	0	927,361
31												
32	470 Land	749	0	0	0	0	749	0	0	0	0	749
33	471 Land Rights	558	0	0	0	0	558	0	0	0	0	558
34	472 Structures and Improvements	6,420	0	245	0	0	6,665	0	250	0	0	6,915
35	473 Services	474,470	0	13,455	(2,018)	0	485,907	0	13,837	(2,076)	0	497,668
36	474 House Regulators and Meter Installations	136,831	0	6,536	(327)	0	143,040	0	6,646	(332)	0	149,354
37	475 Mains	639,807	0	16,634	(1,663)	0	654,778	0	22,106	(2,211)	0	674,673
38	476 Compressor Equipment		0									
39												
40	-All Other	229	0	0	0	0	229	0	0	0	0	229
41	477 Measuring and Regulating Equipment	63,801	0	6,086	(304)	0	69,583	0	6,082	(304)	0	75,361
42	478 Meters	169,636	0	11,001	(550)	0	180,087	0	11,349	(567)	0	190,869
43	479 Other Distribution Equipment	500	0	0	0	0	500	0	0	0	0	500
44	TOTAL DISTRIBUTION PLANT	1,493,001	0	53,957	(4,862)	0	1,542,096	0	60,270	(5,490)	0	1,596,876

BC GAS UTILITY LTD.

GAS PLANT IN SERVICE
FOR THE YEARS ENDING DECEMBER 31, 2005 AND 2006
($000)

Line No.	Particulars	Balance 12/31/2004	CPCN'S	2005 Additions	Retirements	Transfers/ Recovery	Balance 12/31/2005	CPCN'S	2006 Additions	Retirements	Transfers/ Recovery	Balance 12/31/2006
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1	480 Land	$6,572	$0	$21	$0	$0	$6,593	$0	$22	$0	$0	$6,615
2	481 Land Rights	0	0	0	0	0	0	0	0	0	0	0
3	482 Structures and Improvements											
4												
5	-All Other	40,860	0	635	0	0	41,495	0	648	0	0	42,143
6	483 Office Furniture and Equipment											
7	-Fraser Valley / Lochburn / LNG	23,085	0	497	(23)	0	23,559	0	507	(47)	0	24,019
8	-Computers - Hardware	22,058	0	3,501	(2,221)	0	23,338	0	5,632	(5,006)	0	23,964
9	-Computer Software - Non-Infrastructure	33,987	0	3,350	(7,602)	0	29,735	0	1,000	(14,091)	0	16,644
10	-Computer Software - Infrastructure/Custom	107,321	0	12,010	(722)	0	118,609	0	13,133	(27,351)	0	104,391
11												
12												
13	484 Transportation Equipment	205	0	48	0	0	253	0	49	(13)	0	289
14												
15	485 Heavy Work Equipment	8	0	0	(8)	0	0	0	0	0	0	0
16	486 Tools and Work Equipment	27,336	0	2,177	(178)	0	29,335	0	2,221	(161)	0	31,395
17	487 Equipment on Customer's Premises	1,644	0	0	0	0	1,644	0	0	0	0	1,644
18	488 Communication Equipment	15,568	0	1,069	(779)	0	15,858	0	1,091	(87)	0	16,862
19	489 Other General Equipment											
20	-Stores Material, Capital	0	0	0	0	0	0	0	0	0	0	0
21	-All Other	0	0	0	0	0	0	0	0	0	0	0
22												
23	TOTAL GENERAL EQUIPMENT	278,644	0	23,308	(11,533)	0	290,419	0	24,303	(46,756)	0	267,966
24												
25	492 Gas Plant Held for Future Use	0	0	0	0	0	0	0	0	0	0	0
26	496 Unclassified Plant	0	0	0	0	0	0	0	0	0	0	0
27	497 Allowance for Funds Used											
28	During Construction	0	0	0	0	0	0	0	0	0	0	0
29	498 Overhead Charged To Construction	252,915	0	17,917	0	0	270,832	0	18,437	0	0	289,269
30	499 Plant Suspense	0	0	0	0	0	0	0	0	0	0	0
31												
32	TOTAL UNCLASSIFIED PLANT	252,915	0	17,917	0	0	270,832	0	18,437	0	0	289,269
33												
34	TOTAL CAPITAL	$2,950,816	$9,436	$104,073	($17,767)	$0	$3,046,558	$23,097	$109,078	($54,904)	$0	$3,123,829

GAS PLANT IN SERVICE
FOR THE YEAR ENDING DECEMBER 31, 2007
($000)

Line No.	B.C.U.C. Account	Balance 12/31/2006	CPCN'S	2007 Additions	Retirements	Transfers/ Recovery	Balance 12/31/2007
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	401 Franchise Consents	$99	$0	$0	$0	$0	$99
2	402 Other Intangible Plant	148	0	0	0	0	148
3	TOTAL INTANGIBLE PLANT	247	0	0	0	0	247
4							
5	430 Manufact'd Gas - Land	31	0	0	0	0	31
6	432 Manufact'd Gas - Struct. & Improvements	413	0	0	0	0	413
7	433 Manufacturing Equipment	269	0	0	0	0	269
8	434 Gas Holders - Manufacturing	353	0	0	0	0	353
9	436 Compressed Equipment	53	0	0	0	0	53
10	437 Measuring and Regulating Equipment	295	0	0	0	0	295
11	440/441 Land in Fee Simple and Land Rights	915	0	0	0	0	915
12	442 Structures and Improvements	4,347	0	0	0	0	4,347
13	443 Gas Holders - Storage	18,981	0	218	0	0	19,199
14	446 Compressor Equipment	0	0	0	0	0	0
15	447 Measuring and Regulating Equipment	0	0	0	0	0	0
16	448 Purification Equipment	0	0	0	0	0	0
17	449 Local Storage Equipment	16,453	0	0	0	0	16,453
18	TOTAL MANUFACTURED GAS / LOCAL STORAGE	42,110	0	218	0	0	42,328
19							
20	460 Land in Fee Simple	22,354	0	0	0	0	22,354
21	461 Land Rights	29,564	0	241	0	0	29,805
22	462 Compressor Structures	14,375	3,972	301	0	0	18,648
23	463 Measuring Structures	3,048	0	0	0	0	3,048
24	464 Other Structures and Improvements	4,282	0	0	0	0	4,282
25	465 Mains	712,820	49,262	3,579	(178)	0	765,483
26	466 Compressor Equipment	105,408	9,928	40	0	0	115,376
27	467 Measuring and Regulating Equipment	32,221	5,958	699	0	0	38,878
28	468 Communication Structures and Equipment	3,289	0	522	0	0	3,811
29	469 Other Transmission Equipment	0	0	0	0	0	0
30	TOTAL TRANSMISSION PLANT	927,361	69,120	5,382	(178)	0	1,001,685
31							
32	470 Land	749	0	0	0	0	749
33	471 Land Rights	558	0	0	0	0	558
34	472 Structures and Improvements	6,915	0	238	0	0	7,153
35	473 Services	497,668	0	14,329	(2,149)	0	509,848
36	474 House Regulators and Meter Installations	149,354	0	6,743	(337)	0	155,760
37	475 Mains	674,673	0	15,310	(1,531)	0	688,452
38	476 Compressor Equipment						
39							
40	-All Other	229	0	0	0	0	229
41	477 Measuring and Regulating Equipment	75,361	0	6,035	(301)	0	81,095
42	478 Meters	190,869	0	11,723	(586)	0	202,006
43	479 Other Distribution Equipment	500	0	0	0	0	500
44	TOTAL DISTRIBUTION PLANT	1,596,876	0	54,378	(4,904)	0	1,646,350

BC GAS UTILITY LTD.

GAS PLANT IN SERVICE
FOR THE YEAR ENDING DECEMBER 31, 2007
($000)

Line No.	B.C.U.C. Account	Balance 12/31/2006	CPCN'S	2007 Additions	Retirements	Transfers/ Recovery	Balance 12/31/2007
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	480 Land	$6,615	$0	$22	$0	$0	$6,637
2	481 Land Rights	0	0	0	0	0	0
3	482 Structures and Improvements						
4							
5	-All Other	42,143	0	660	0	0	42,803
6	483 Office Furniture and Equipment						
7	-Fraser Valley / Lochburn / LNG	24,019	0	518	(39)	0	24,498
8	-Computers - Hardware	23,964	0	6,271	(5,536)	0	24,699
9	-Computer Software - Non-Infrastructure	16,644	0	14,789	(14,737)	0	16,696
10	-Computer Software - Infrastructure/Custom	104,391	0	0	0	0	104,391
11							
12							
13	484 Transportation Equipment	289	0	48	(24)	0	313
14							
15	485 Heavy Work Equipment	0	0	0	0	0	0
16	486 Tools and Work Equipment	31,395	0	2,266	(164)	0	33,497
17	487 Equipment on Customer's Premises	1,644	0	0	0	0	1,644
18	488 Communication Equipment	16,862	0	1,112	(556)	0	17,418
19	489 Other General Equipment						
20	-Stores Material, Capital	0	0	0	0	0	0
21	-All Other	0	0	0	0	0	0
22							
23	TOTAL GENERAL EQUIPMENT	267,966	0	25,686	(21,056)	0	272,596
24							
25	492 Gas Plant Held for Future Use	0	0	0	0	0	0
26	496 Unclassified Plant	0	0	0	0	0	0
27	497 Allowance for Funds Used						
28	During Construction	0	0	0	0	0	0
29	498 Overhead Charged To Construction	289,269	0	19,001	0	0	308,270
30	499 Plant Suspense	0	0	0	0	0	0
31							
32	TOTAL UNCLASSIFIED PLANT	289,269	0	19,001	0	0	308,270
33							
34	TOTAL CAPITAL	$3,123,829	$69,120	$104,665	($26,138)	$0	$3,271,476

BC GAS UTILITY LTD.
SUMMARY OF CAPITAL ADDITIONS AND CAPITAL EFFICIENCY
FOR THE YEARS ENDING DECEMBER 31, 1997 TO 2007
($000)

Line No.	Particulars	1997	1998	1999	2000	Preliminary 2001	Projected 2002	Forecast 2003	Forecast 2004	Forecast 2005	Forecast 2006	Forecast 2007
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1	**Capital Expenditures**											
2												
3	A: Mains, Services, Meters (Tab3, Page 3.1)	$37,451	$30,645	$31,644	$29,866	$26,684	$27,348	$33,460	$32,819	$33,792	$34,792	$35,927
4												
5	B: Systems Integrity and Reliability (Tab 3, Page 3.2)	17,340	11,728	23,445	28,189	17,514	20,385	25,386	25,064	17,310	21,977	14,931
6												
7	C: All Other Plant (Tab 3, Page 3.3)	27,027	30,840	27,504	30,373	27,914	27,000	30,000	30,249	31,742	33,345	34,012
8												
9	Subtotal - Categories A, B, & C	81,818	73,213	82,593	88,428	72,112	74,733	88,846	88,132	82,844	90,114	84,870
10												
11	D: CPCNs	6,667	20,937	35,165	371,901	58,945	31,137	9,361	9,137	22,509	66,708	4,538
12												
13	TOTAL CAPITAL EXPENDITURES	$88,485	$94,150	$117,758	$460,329	$131,057	$105,870	$98,207	$97,269	$105,353	$156,822	$89,408
14												
15	Capital Efficiency Mechanism - Gross Incentive/ (Penalty		($5,433)	($5,070)	($9,769)	($5,138)						
16												
17	Capital Efficiency Incentive / (Penalty) - Annual Rate Base Impact											
18	1998		($2,717)	($3,622)	($1,811)							
19	1999			(2,536)	(3,380)	($1,690)						
20	2000				(4,886)	(6,513)	($3,256)					
21	2001					(2,073)	(2,763)	($1,381)				
22												
23	TOTAL CAPITAL PENALTY - RATE BASE IMPACT	-	($2,717)	($6,158)	($10,077)	($10,276)	($6,019)	($1,381)	-	-	-	-
24												
25	**RECONCILIATION OF CAPITAL EXPENDITURES TO PLANT ADDITIONS**											
26	Categories A, B & C											
27												
28	Capital Expenditures - Categories A, B & C	$81,818	$73,213	$82,593	$88,428	$72,112	$74,733	$88,846	$88,132	$82,844	$90,114	$84,870
29												
30	Add - Opening WIP	8,696	11,382	12,963	18,840	23,988	26,272	15,591	12,896	16,091	13,858	14,461
31	Adjustment to Opening Plant	(802)	1,121	1,195	(35)	4,132	1					
32												
33	Less- Closing WIP	(11,382)	(12,963)	(18,840)	(23,988)	(26,272)	(15,591)	(12,896)	(16,091)	(13,858)	(14,461)	(14,666)
34												
35	Add - AFUDC		-	265	1,252	1,254	1,631	1,682	1,161	1,079	1,130	999
36	Add - O'H Capitalized	32,557	29,095	29,266	23,307	23,794	25,162	25,879	27,071	17,917	18,437	19,001
37												
38	TOTAL ADDITIONS TO GAS PLANT IN SERVICE- CATEGORIES A, B, & C	$110,887	$101,848	$107,442	$107,804	$99,008	$112,208	$119,102	$113,169	$104,073	$109,078	$104,665
39												
40	Category D - CPCNs											
41												
42	Capital Expenditures - CPCNs	$6,667	$20,937	$35,165	$371,901	$58,945	$31,137	$9,361	$9,137	$22,509	$66,708	$4,538
43	Add - AFUDC - CPCNs		986	1,343	9,805	2,074	930	341	275	674	1,935	136
44												
45	Add - Opening WIP - CPCNs	5,071	9,446	29,383	43,033	424,587	71,588	32,614	10,471	10,210	23,957	69,503
46	Adjustment to Opening Plant		4,101	3,595	(152)	(104)	300					
47	Transfer to CustomerWorks						(21,039)					
48												
49	Less - Closing WIP - CPCNs	(9,446)	(29,383)	(43,033)	(424,587)	(71,588)	(32,614)	(10,471)	(10,210)	(23,957)	(69,503)	(5,057)
50												
51	TOTAL CPCN ADDITIONS TO OPENING GAS PLANT IN SERVICE	$2,292	$6,087	$26,453	-	$413,914	$50,302	$31,845	$9,673	$9,436	$23,097	$69,120
52												
53	TOTAL PLANT ADDITIONS	$113,179	$107,935	$133,895	$107,804	$512,922	$162,510	$150,947	$122,842	$113,509	$132,175	$173,785

BC GAS UTILITY LTD.
MAINS, SERVICES & METER CAPITAL EXPENDITURES
FOR THE YEARS ENDING DECEMBER 31, 1997 TO 2007
($000)

Line No.	Particulars	1997	1998	1999	2000	Preliminary 2001	Projected 2002	Forecast 2003	Forecast 2004	Forecast 2005	Forecast 2006	Forecast 2007
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1	**MAINS, SERVICES & METERS**											
2												
3	**Mains - Recurring**											
4												
5	Cost Driver: Customer Additions	16,468	10,447	11,293	7,262	4,874	7,476	9,265	8,464	8,521	8,793	8,864
6	Services / Customer Ratio		103.92%	84.92%	114.36%	147.93%						
7	Service Additions		10,857	9,590	8,305	7,210						
8												
9	Metres / Service Addition		17.1	16.2	14.3	11.7						
10												
11	$ / metre of Main		$30.62	$37.00	$49.60	$58.00						
12												
13	$ / metre of Main - Real ($ 2002)		$32.18	$38.77	$51.40	$58.99						
14												
15	Total Cost ($000)	**$7,355**	**$5,683**	**$5,735**	**$5,887**	**$4,594**	**$4,740**	**$6,000**	**$5,798**	**$5,914**	**$6,140**	**$6,372**
16												
17	**Services**											
18												
19	Cost Driver: Customer Additions	16,468	10,447	11,293	7,262	4,874	7,476	9,265	8,464	8,521	8,793	8,864
20	Services / Customer Ratio		103.92%	84.92%	114.36%	147.93%						
21	Service Additions		10,857	9,590	8,305	7,210						
22												
23	$ / Service Addition		$1,035.00	$1,088.63	$1,122.82	$1,168.79						
24												
25	$ / Service Addition - Real ($ 2002)		$1,087.65	$1,140.58	$1,163.60	$1,188.66						
26												
27	Total Costs ($000)	**$13,945**	**$11,237**	**$10,440**	**$9,325**	**$8,427**	**$8,446**	**$10,577**	**$9,939**	**$10,349**	**$10,664**	**$11,097**
28												
29	**Gas Measurement - New Meters & Meter Recalled**											
30												
31	Cost Driver: New Meters & Meter Recalled		52,319	53,739	46,305	51,424						
32												
33	$ / New Meter & Meter Recalled		$262.33	$287.85	$316.46	$265.69						
34												
35	$ / New Meter & Meter Recalled - Real ($ 2002)		$275.67	$301.59	$327.95	$270.21						
36												
37	Total Cost ($000)	**$16,151**	**$13,725**	**$15,469**	**$14,654**	**$13,663**	**$14,162**	**$16,883**	**$17,082**	**$17,529**	**$17,988**	**$18,458**
38												
39	**TOTAL COST - MAINS, SERVICES & METERS ($000)**	**$37,451**	**$30,645**	**$31,644**	**$29,866**	**$26,684**	**$27,348**	**$33,460**	**$32,819**	**$33,792**	**$34,792**	**$35,927**

BC GAS UTILITY LTD.
SYSTEM INTEGRITY AND RELIABILITY CAPITAL EXPENDITURES
FOR THE YEARS ENDING DECEMBER 31, 1997 TO 2007
($000)

Line No.	Particulars	1997	1998	1999	2000	Preliminary 2001	Projected 2002	Forecast 2003	Forecast 2004	Forecast 2005	Forecast 2006	Forecast 2007
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1	**SYSTEM INTEGRITY AND RELIABILITY**											
2												
3	**Transmission Plant**											
4												
5	Cost Driver: System Throughput											
6	Forecast - 10^3 m^3 / d		31,791	31,791	33,036	34,404						
7												
8	$ / 10^3 m^3 / d of System Throughput		$263.60	$334.80	$277.70	$248.70						
9												
10	$ / 10^3 m^3 / d of System Throughput, - Real ($ 2002)		$277.01	$350.78	$287.79	$252.93						
11												
12	Total Cost ($000)	**$11,210**	**$8,381**	**$10,644**	**$9,174**	**$8,556**	**$11,418**	**$8,167**	**$11,577**	**$5,807**	**$4,943**	**$5,756**
13												
14												
15	**System Improvements / Reinforcements**											
16												
17	Cost Driver: Customers - EOY	729,491	739,938	751,231	758,493	763,367	770,843	780,108	788,572	797,093	805,886	814,750
18												
19	$ / Customer - EOY		$5.00	$14.00	$21.00	$12.00						
20												
21	$ / Customer - EOY - Real ($ 2002)		$5.25	$14.67	$21.76	$12.20						
22												
23	Total Cost ($000)	**$6,130**	**$3,347**	**$10,825**	**$15,929**	**$8,855**	**$8,967**	**$17,219**	**$13,487**	**$11,503**	**$17,034**	**$9,175**
24												
25	**Meter Set Protection**			**$1,976**	**$3,086**	**$103**	**-**	**-**	**-**	**-**	**-**	**-**
26												
27	**TOTAL COST - SYSTEM INTEGRITY AND**											
28	**RELIABILITY ($000)**	**$17,340**	**$11,728**	**$23,445**	**$28,189**	**$17,514**	**$20,385**	**$25,386**	**$25,064**	**$17,310**	**$21,977**	**$14,931**

($000)

Line No.	Particulars	1997	1998	1999	2000	Preliminary 2001	Projected 2002	Forecast 2003	Forecast 2004	Forecast 2005	Forecast 2006	Forecast 2007
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1	**ALL OTHER PLANT**											
2												
3	**Information Technology Capital**	$11,369	$16,300	$17,504	$17,800	$18,630	$17,000	$17,900	$17,988	$19,298	$20,653	$21,066
4												
5	**Non - Information Technology Capital**	15,658	14,540	10,000	12,573	9,284	10,000	12,100	12,261	12,444	12,692	12,946
6												
7												
8	**TOTAL COST - ALL OTHER PLANT**	**$27,027**	**$30,840**	**$27,504**	**$30,373**	**$27,914**	**$27,000**	**$30,000**	**$30,249**	**$31,742**	**$33,345**	**$34,012**

BC GAS UTILITY LTD.
CPCN EXPENDITURES (Including AFUDC)
FOR THE YEARS ENDING DECEMBER 31, 1997 TO 2007
($000)

Line No.	Particulars	BCUC Order#	1997	1998	1999	2000	Preliminary 2001	Projected 2002	Forecast 2003	Forecast 2004	Forecast 2005	Forecast 2006	Forecast 2007
	(1)	(2)	(3)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1	**CPCN**												
2													
3	**Approved CPCNs**												
4													
5	Miscellaneous Small CPCNs (1996/97)		$8,761	$475									
6													
7	Integrated Business Information System (IBIS)	C-8-98	4,887	17,615									
8													
9	Coastal Facilities	C-14-98			$22	$7,594	$1,092						
10													
11	Fraser River Crossing	C-1-99		246	3,185	5,754	191						
12													
13	Customer Information Systems- Mercury /Pathfinder	C-7-99		3,587	9,502	11,867	13,404						
14													
15	Southern Crossing Pipeline	C-11-99	6,147		20,906	329,550	31,350	$8,129					
16													
17	Fraser Valley Compressor Station	C-14-99			2,218	20,549	1,936	3,980					
18													
19	Integrated Resource Management	C-15-99			51	4,755	915						
20													
21	Work Management System & Preventative Maintenance	C-6-00			627	1,637	2,712	6,745					
22													
23	Transmission Pipeline Integrity Plan	C-15-01 & C-3-02					9,419	8,927	$3,838				
24													
25	Armstrong Compressor Station	C-6-02						4,286					
26													
27	**Proposed CPCNs**												
28													
29	Transmission Pipeline Integrity Plan								5,864	$9,412	$10,448	$4,667	$4,674
30													
31	Nichol to Coquitlam Loop										12,735	11,155	
32													
33	Naramata Loop											32,963	
34													
35	Kitchener B Compressor Unit Addition											19,858	
36													
37	TOTAL COSTS - CPCNs		**$19,795**	**$21,923**	**$36,511**	**$381,706**	**$61,019**	**$32,067**	**$9,702**	**$9,412**	**$23,183**	**$68,643**	**$4,674**

BC GAS UTILITY LTD.
CONTRIBUTIONS IN AID OF CONSTRUCTION (CIAOC)
ACCOUNT 211
FOR THE YEARS ENDING DECEMBER 31, 2003 TO 2007

CIAOC are made by customers in respect of mains extensions, service line installations and for other billable work (relocation of lines etc.). In addition, BC Gas credits Account 211 with income tax credits related to computer software added to gas plant in service.

BC GAS UTILITY LTD.
CONTRIBUTIONS IN AID OF CONSTRUCTION
FOR THE YEARS ENDING DECEMBER 31, 2003 TO 2005
($000)

Line No.	Particulars		Balance 12/31/2002	2003 Additions	2003 Retirements	Balance 12/31/2003	2004 Additions	2004 Retirements	Balance 12/31/2004	2005 Additions	2005 Retirements	Balance 12/31/2005
	(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	DSEP/GEAP	211-06	$12,671	$0	$0	$12,671	$0	$0	$12,671	$0	$0	$12,671
2												
3	NGV Conversion Grants	211-07	0	0	0	0	0	0	0	0	0	0
4												
5	NGV Station Grants	211-08	0	0	0	0	0	0	0	0	0	0
6												
7	Furniture & Equipment	211-10	111	0	0	111	0	0	111	0	0	111
8												
9	Software Tax Savings - Non-Infrastructure	211-11	13,929	542	(750)	13,721	325	(1,956)	12,090	1,251	(4,271)	9,070
10	- Infrastructure/Custom	211-11	40,027	6,897	(245)	46,679	4,639	(224)	51,094	4,483	(2,741)	52,836
11	Service Installation Fee	211-12	13,558	1,236	0	14,794	1,700	0	16,494	1,919	0	18,413
12												
13	Other	211-00 to 05	57,273	3,187	0	60,460	3,520	0	63,980	3,750	0	67,730
14												
15	TOTAL (Tab 3, Page 1 - 1.1)		137,569	11,862	(995)	148,436	10,184	(2,180)	156,440	11,403	(7,012)	160,831
16												
17												
18												
19	Amortization	211-15 to 22										
20												
21	- Software Tax Savings - Non-Infrastructure		(7,660)	(1,741)	750	(8,651)	(2,744)	1,956	(9,439)	(2,418)	4,271	(7,586)
22	- Infrastructure/Custom		(9,631)	(5,003)	245	(14,389)	(5,835)	224	(20,000)	(6,387)	2,741	(23,646)
23	- Other		(15,937)	(1,843)	0	(17,780)	(1,940)	0	(19,720)	(2,055)	0	(21,775)
24												
25												
26	Total Amortization		(33,228)	(8,587)	995	(40,820)	(10,519)	2,180	(49,159)	(10,860)	7,012	(53,007)
27												
28	NET	21	$104,341	$3,275	$0	$107,616	($335)	$0	$107,281	$543	$0	$107,824

BC GAS UTILITY LTD.
CONTRIBUTIONS IN AID OF CONSTRUCTION
FOR THE YEARS ENDING DECEMBER 31, 2006 AND 2007
($000)

Line No.	Particulars		Balance 12/31/2005	2006 Additions	2006 Retirements	Balance 12/31/2006	2007 Additions	2007 Retirements	Balance 12/31/2007
	(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	DSEP/GEAP	211-06	$12,671	$0	$0	$12,671	$0	$0	$12,671
2									
3	NGV Conversion Grants	211-07	0	0	0	0	0	0	0
4									
5	NGV Station Grants	211-08	0	0	0	0	0	0	0
6									
7	Furniture & Equipment	211-10	111	0	0	111	0	0	111
8									
9	Software Tax Savings - Non-Infrastructure	211-11	9,070	409	(758)	8,721	408	(4,966)	4,163
10	- Infrastructure/Custom	211-11	52,836	5,372	(6,497)	51,711	5,336	(15,709)	41,338
11	Service Installation Fee	211-12	18,413	2,095	0	20,508	2,269	0	22,777
12									
13	Other	211-00 to 05	67,730	3,970	0	71,700	4,199	0	75,899
14									
15	TOTAL (Tab 3, Page 1.2)		160,831	11,846	(7,255)	165,422	12,212	(20,675)	156,959
16									
17									
18									
19	Amortization	211-15 to 22							
20									
21	- Software Tax Savings - Non-Infrastructure		(7,586)	(1,814)	758	(8,642)	(1,744)	4,966	(5,420)
22	- Infrastructure/Custom		(23,646)	(6,605)	6,497	(23,754)	(6,464)	15,709	(14,509)
23	- Other		(21,775)	(2,179)	0	(23,954)	(2,313)	0	(26,267)
24									
25									
26	Total Amortization		(53,007)	(10,598)	7,255	(56,350)	(10,521)	20,675	(46,196)
27									
28	NET	211	$107,824	$1,248	$0	$109,072	$1,691	$0	$110,763

BC UTILITY LTD.
CONTINUITY IN CONTRIBUTIONS IN AID OF CONSTRUCTION
FOR THE YEARS ENDING DECEMBER 31, 2001 AND 2002
($000)

Line No.	Particulars	B.C.U.C. Account	Balance 12/31/2000	Preliminary 2001 Opening Adjustment	Preliminary 2001 Additions	Preliminary 2001 Balance 12/31/2001	Projected 2002 Opening Adjustments	Projected 2002 Additions	Projected 2002 Balance 12/31/2002
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	DSEP/GEAP	211-06	$12,671	$0	$0	$12,671	$0	$0	$12,671
2									
3	NGV Conversion Grants	211-07	65	0	0	65	(65)	0	0
4									
5	NGV Station Grants	211-08	0	0	0	0	0	0	0
6									
7	Furniture & Equipment	211-10	111	0	0	111	0	0	111
8									
9	Computer Software Tax Savings - Desktop & Other	211-11	8,278	(87)	4,510	12,701	0	1,228	13,929
10	- Infrastructure/Custom		30,296	(319)	10,697	32,508	0	7,519	40,027
11									
12	Service Installation Fee	211-12	9,605	0	2,070	11,675	0	1,883	13,558
13									
14	Other	211-00 to 05	48,544	(3)	6,146	54,687	0	2,586	57,273
15									
16	TOTAL		109,570	(409)	23,423	124,418	(65)	13,216	137,569
17									
18									
19	Amortization								
20									
21	Computer Software Tax Savings - Desktop & Other	211-15 to 22	(5,099)	0	(973)	(6,072)	0	(1,588)	(7,660)
22	- Infrastructure/Custom		(2,788)	0	(3,747)	(5,567)	0	(4,064)	(9,631)
23									
24	- Other		(12,608)	0	(1,575)	(14,183)	0	(1,754)	(15,937)
25									
26									
27	Total Amortization		(20,495)	0	(6,295)	(25,822)	0	(7,406)	(33,228)
28									
29									
30	NET	211	$89,075	($409)	$17,128	$98,596	($65)	$5,810	$104,341

BC UTILITY LTD.
NET GAS PLANT IN SERVICE
FOR THE YEARS ENDING DECEMBER 31, 2003 TO 2007
($000)

Line No.	Particulars	2003 Amount	2004 Amount	2005 Amount	2006 Amount	2007 Amount	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Gas Plant in Service - December 31, Previous Year	$2,711,233	$2,849,113	$2,950,816	$3,046,558	$3,123,829	- Tab 3, Page 4.6
2							
3	Add: CPCNs on January 1, Beginning of the Year	31,845	9,673	9,436	23,097	69,120	- Tab 3, Page 1
4							
5	Adjusted Opening Gas Plant in Service	2,743,078	2,858,786	2,960,252	3,069,655	3,192,949	
6							
7	Intangible Plant	837	837	837	837	837	- Tab 3, Page 1
8							
9	Less: Contribution in Aid of Construction	(137,569)	(148,436)	(156,440)	(160,831)	(165,422)	- Tab 3, Page 4.1
10							
11	Less: Accumulated Depreciation and Amortization	(467,993)	(527,002)	(585,983)	(655,161)	(691,047)	- Tab 4. Page 2
12							
13	Net Gas Plant in Service as at January 1,	$2,138,353	$2,184,185	$2,218,666	$2,254,500	$2,337,317	- Tab 3, Page 1

($000)

			Preliminary 2001					Projected 2002			
Line No.	B.C.U.C. Account	Balance 12/31/2000	CPCN'S	Adjustments	Additions	Retirements	Balance 12/31/2001	CPCN'S	Additions	Retirements	Balance 12/31/2002
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	401 Franchise Consents	$99	0	$0	$0	$0	$99	$0	$0	$0	$99
2	402 Other Intangible Plant	148	0	0	0	0	148	0	0	0	148
3											
4	TOTAL INTANGIBLE PLANT	247	0	0	0	0	247	0	0	0	247
5											
6	430 Manufactured Gas - Land	31	0	0	0	0	31	0	0	0	31
7	432 Manufactured Gas - Structures & Improvements	384	0	0	1	0	385	0	28	0	413
8	433 Manufacturing Equipment	136	0	0	0	0	136	0	133	0	269
9	434 Gas Holders - Manufacturing	343	0	0	10	0	353	0	0	0	353
10	436 Compressor Equipment	53	0	0	0	0	53	0	0	0	53
11	437 Measuring and Regulating Equipment	322	0	0	1	(28)	295	0	0	0	295
12	440/441 Land in Fee Simple and Land Rights	915	0	0	0	0	915	0	0	0	915
13	442 Structures and Improvements	2,841	0	0	58	0	2,899	0	1,365	0	4,264
14	443 Gas Holders - Storage	10,261	0	0	0	0	10,261	0	2,018	0	12,279
15	446 Compressor Equipment	0	0	0	0	0	0	0	0	0	0
16	447 Measuring and Regulating Equipment	0	0	0	0	0	0	0	0	0	0
17	448 Purification Equipment	0	0	0	0	0	0	0	0	0	0
18	449 Local Storage Equipment	15,509	0	0	0	(30)	15,479	0	968	0	16,447
19											
20	TOTAL MANUFACTURED GAS / LOCAL STORAGE	30,795	0	0	70	(58)	30,807	0	4,512	0	35,319
21											
22	460 Land in Fee Simple	21,793	275	0	18	0	22,086	264	4	0	22,354
23	461 Land Rights	9,387	12,351	0	42	0	21,780	2,760	1,429	0	25,969
24	462 Compressor Structures	9,356	2,697	0	2	0	12,055	463	570	0	13,088
25	463 Measuring Structures	2,840	212	0	19	(27)	3,044	0	4	0	3,048
26	464 Other Structures and Improvements	381	0	105	86	0	572	3,710	0	0	4,282
27	465 Mains	266,619	318,827	8,779	14,096	(1,220)	607,101	31,177	6,205	(1,112)	643,371
28	466 Compressor Equipment	39,175	51,387	0	333	(11)	90,884	4,730	1,083	0	96,697
29	467 Measuring and Regulating Equipment	24,132	2,202	33	1,063	(2,129)	25,301	60	399	0	25,760
30	468 Communication Structures and Equipment	321	0	(10)	251	(13)	549	0	751	0	1,300
31	469 Other Transmission Equipment	0	0	0	0	0	0	0	0	0	0
32	TOTAL TRANSMISSION PLANT	374,004	387,951	8,907	15,910	(3,400)	783,372	43,164	10,445	(1,112)	835,869
33											
34	470 Land	774	0	(23)	4	(24)	731	0	18	0	749
35	471 Land Rights	469	0	0	58	0	527	0	31	0	558
36	472 Structures and Improvements	5,498	0	0	543	(103)	5,938	0	18	0	5,956
37	473 Services	434,348	0	369	9,811	(1,095)	443,433	0	10,005	(1,501)	451,937
38	474 House Regulators and Meter Installations	117,448	21	544	5,467	(2,399)	121,081	0	3,795	(190)	124,686
39	475 Mains	585,324	11	(4,457)	11,031	(485)	591,424	0	14,571	(1,457)	604,538
40	476 Compressor Equipment										
41											
42	-All Other	0	0	229	0	0	229	0	0	0	229
43	477 Measuring and Regulating Equipment	46,221	0	(231)	4,238	(2,326)	47,902	2	3,817	(191)	51,530
44	478 Meters	133,269	0	(166)	7,540	(2,114)	138,529	0	11,586	(579)	149,536
45	479 Other Distribution Equipment	0	0	0	0	0	0	0	500	0	500
46											
47	TOTAL DISTRIBUTION PLANT	1,323,351	32	(3,735)	38,692	(8,546)	1,349,794	2	44,341	(3,918)	1,390,219

BC GAS UTILITY LTD.
CONTINUITY OF GAS PLANT IN SERVICE (CONT'D)
FOR THE YEARS ENDING DECEMBER 31, 2001 AND 2002
($000)

			Preliminary 2001					Projected 2002			
Line No.	B.C.U.C. Account	Balance 12/31/2000	CPCN'S	Adjustments	Additions	Retirements	Balance 12/31/2001	CPCN'S	Additions	Retirements	Balance 12/31/2002
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	480 Land	$6,545	$0	$0	$0	($14)	$6,531	$0	$0	$0	$6,531
2	481 Land Rights	0	0	0	0	0	0	0	0	0	0
3	482 Structures and Improvements										
4											
5	-All Other	39,130	0	(225)	2,423	(2,897)	38,431	0	1,201	0	39,632
6	483 Office Furniture and Equipment						0				
7	-Furniture & Equipment	17,041	4,946	0	604	0	21,200	492	596	(118)	22,170
8	-Computers - Hardware	25,340	1,997	3,053	803	(5,425)	23,752	820	5,174	(7,056)	22,690
9	-Computer Software - Non-Infrastructure	34,520	0	(3,020)	4,904	(717)	35,687	0	3,540	0	39,227
10	-Computer Software - Infrastructure/Custom	51,534	15,854	0	9,565	(386)	59,126	5,315	14,537	0	78,978
11											
12											
13	484 Transportation Equipment	1,044	0	0	68	(34)	1,078	0	13	(682)	409
14	485 Heavy Work Equipment	14	0	0	4	0	18	0	0	(6)	12
15	486 Tools and Work Equipment	20,561	0	0	1,813	0	22,374	(6)	1,806	(646)	23,528
16	487 Equipment on Customer's Premises	2,227	0	0	0	0	2,227	0	0	(583)	1,644
17	488 Communication Equipment	14,229	3,134	0	358	(62)	17,361	515	881	(3,964)	14,793
18	489 Other General Equipment	0	0	0	0	0	0	0		0	0
19											
20	TOTAL GENERAL EQUIPMENT	215,445	25,931	(192)	20,542	(12,795)	227,785	7,136	27,748	(13,055)	249,614
21											
22	492 Gas Plant Held for Future Use	0	0	0	0	0	0	0	0	0	0
23	496 Unclassified Plant	0	0	0	0	0	0	0	0	0	0
24	497 Allowance for Funds Used										
25	During Construction	0	0	0	0	0	0	0	0	0	0
26	498 Overhead Charged To Construction	151,009	0	0	23,794	0	174,803	0	25,162	0	199,965
27	499 Plant Suspense	0	0	0	0	0	0	0	0	0	0
28											
29	TOTAL UNCLASSIFIED PLANT	151,009	0	0	23,794	0	174,803	0	25,162	0	199,965
30											
31											
32	TOTAL CAPITAL	$2,094,851	$413,914	$4,980	$99,008	($24,799)	$2,566,808	$50,302	$112,208	($18,085)	$2,711,233

Unamortized Deferred Charges are carried in the regulatory schedules on a net-of-tax basis. Tab 3, Pages 5.6 to 5.15 show the 2003 to 2007 forecast Unamortized Deferred Charges and Amortization. The forecast mid-year balances are:

- 2003 - $31.5 million
- 2004 - $4.5 million
- 2005 - ($7.7) million
- 2006 - ($15.1) million
- 2007 - ($18.2) million

Section H
Tab 3
Page 5

($000)

Reference Tab 3 Pages 5.6 to 5.15 Line No.	Account	Status	Particulars
(1)	(2)	(3)	(4)
1	Deferred Interest	Request	BC Gas requests a 3-year straight-line amortization commencing January 1, 2003 of the projected December 31, 2002 balance deferred pursuant to BCUC Orders No. G-85-97 and G-48-00.
4	Market Rebate Incentive - Water Heater Grants	Continuation	Orders No. G-31-84 (ING), G-33-87 (CNG), OIC#824/89 (LM), Decision dated August 12, 1994, Page 34. Continuation of approved amortization until final year of amortization in 2004.
6	NGV Conversion Grants	Continuation/ Request	Continuation of the NGV Grant Program as approved by BCUC Order No. G-98-99. Request for additions for 2003 and 5-year amortization.
12	2003 Revenue Requirement / PBR Multi Year	New Request	Approval of the deferred costs and 5-year amortization is requested in this Application.
14	Demand Side Management	Continuation/ Request	Continuation of programs similar to those approved by BCUC Order No. G-85-97. Approval of $1,500,000 expenditures for 2003 and 3-year amortization are requested in this application.

Section H
Tab 3
Page 5.1

($000)

Reference Tab 3 Pages 5.6 to 5.15 Line No.	Account	Status	Particulars
(1)	(2)	(3)	(4)
15	Demand Side Management DRIA	Request	Request for 3-year amortization commencing in 2003 for amounts recorded pursuant to BCUC Orders No. G-85-97 and G-48-00.
18	Tax Deferral (Property, Federal, and Provincial Taxes and Levies)	New Request	Request to establish deferral account for variances from forecast in Property taxes, income taxes, and government fees. And request for 3-year amortization as a rider.
21 & 22	GCRA and GCRA Interest	Continuation	Amortization of the GCRA balance according to BCUC Orders No. G-124-00 and G-134-01 is assumed with full recovery of the outstanding December 31, 2001 GCRA balance by December 31, 2003. Continuation of the recording of GCRA variances from forecast is also assumed.
23	RSAM	Continuation/ Request	Request to amortize as a rider the projected December 31, 2002 debit balance using a 3-year straight-line amortization. Continuation to accumulate differences between Forecast use rate and actual use of RSAM customers for each year from 2003 to 2007. Any RSAM additions to be amortized over a 3-year straight-line period. BC Gas requests to accumulate the carrying costs of RSAM balance variances from Forecast.

Section H
Tab 3
Page 5.2

($000)

Reference Tab 3 Pages 5.6 to 5.15 Line No.	Account	Status	Particulars
(1)	(2)	(3)	(4)
28	BC Hydro Service Agreement Costs	Request	Request for 2-year amortization commencing in 2003 of costs accumulated per BCUC Orders No. G-85-97 and G-48-00.
33, 34 & 35	Coastal Facilities - Relocation - Fraser Valley NBV Amortization - Extraordinary Plant Loss – Lochburn	Continuation	Continuation of the 5-year amortization as per BCUC Order No. C-14-98.
36	Coastal Facilities - Noncapital Finance Costs	Request	Deferral approved by BCUC Order No. C-14-98. Request for amortization over a 5-year period.
42	ABC-T Project Requirements Phase	Continuation	Two-year amortization commencing in 2003 as per BCUC Order G-24-02.
44	Burner Tip Service	Request	Request for 1-year amortization in 2003 of the projected December 31, 2002 balance.
45	Earnings Sharing Mechanism	Request	Request for the projected December 31, 2002 residual balance recorded as per BCUC Orders No. G-85-97 and G-48-00 to be amortized over a 3-year period commencing in 2003 as an expense.

Section H
Tab 3
Page 5.3

($000)

Reference Tab 3 Pages 5.6 to 5.15 Line No.	Account	Status	Particulars
(1)	(2)	(3)	(4)
47	Salmon Arm Reinforcement	Continuation	Continuation of amortization as per BCUC Order G-26-00. Final year of amortization in 2003.
48	NGV Compression Equipment Recovery	Continuation	Continuation of 10-year amortization as per BCUC Order G-143-99.
49	2001 Rate Design	Continuation	Continuation of amortization per BCUC Order No. G-116-01 (Appendix 1, Page 3) over 3 years starting in 2002.
51 & 52	Overheads Change – Income Tax Refund and CIAOC Software Tax Savings/OH Change	Request	Request for amortization over a 5-year period starting in 2003 of the residual balance of the Overheads Change – Income Tax Refund account and the balance of CIAOC Software Tax Savings/OH Change account.
53	Other Post Employment Benefits	Continuation	Continuation of OPEB regulatory accounting treatment as in previous years.
55	Deferred 2000 SCP Cost of Service	Request	Request for amortization over a 5-year period of SCP 2000 Cost of Service deferred pursuant to BCUC Order No. G-135-99.

Section H
Tab 3
Page 5.4

($000)

Reference Tab 3 Pages 5.6 to 5.15 Line No.	Account	Status	Particulars
(1)	(2)	(3)	(4)
56 & 57	SCP Net Mitigation Revenues and SCP West to East Transmission	Continuation/ Request	Request for approval of 5-year amortization of SCP Third Party Revenues deferred as per BCUC Orders No. G-124-00 and G-123-01 deferral of variances in Third Party Revenues from Forecast.
59	CCT Deferral	Request	Request for a 5-year amortization starting in 2003 of the deferred credit recorded as per BCUC Orders No. G-85-97 and G-48-00.

Section H
Tab 3
Page 5.5

BC GAS UTILITY LTD.

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDING DECEMBER 31, 2003
($000)

Line No.	Particulars	Account	Projected Balance 12/31/2002	Gross Additions	Less-Taxes	Net Additions	Amortization Expense	Amortization Other	Balance 12/31/2003	Mid-Year Average 2003
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Deferred Interest	#17904	($4,077)	$0	$0	$0	$1,359	$0	($2,718)	($3,398)
2										
3	Market Rebate Incentive									
4	- Water Heater Grants	#17909	31	0	0	0	(23)	0	8	20
5										
6	NGV Conversion Grants	#17977	373	525	(192)	333	(78)	0	628	501
7										
8	Local Gas Development	#17910	0	0	0	0	0	0	0	0
9	Fraser Valley Gas Exploration	#17928	0	0	0	0	0	0	0	0
10										
11	Revenue Req. Hearing - 1998-2001	#17960	0	0	0	0	0	0	0	0
12	2003 Revenue Requirement / PBR Multi Yr		184	0	0	0	(37)	0	147	166
13										
14	Demand Side Management	#17916	2,060	1,500	(548)	952	(857)	0	2,155	2,108
15	Demand Side Management DRIA	#17961	(150)	0	0	0	50	0	(100)	(125)
16										
17										
18	Tax Deferral (Property, Fed. & Prov.)	#17915	0	0	0	0	0	0	0	0
19	Westar Receivable	#17919	0	0	0	0	0	0	0	0
20										
21	G.C.R.A.	#17926	28,943	0	0	0	0	(28,943)	0	14,472
22	G.C.R.A. Interest	#17973	668	0	0	0	0	(668)	0	334
23	RSAM	#17927	30,547	0	0	0	0	(10,182)	20,365	25,456
24										
25	Buy/Sell Operating Costs	#17930	0	0	0	0	0	0	0	0
26	Revelstoke Propane Cost	#27902	0	0	0	0	0	0	0	0
27										
28	B.C. Hydro Service Agreement Costs	#17963	943	0	0	0	(472)	0	471	707
29	Recovery of Non-Utility Service	#27904	0	0	0	0	0	0	0	0
30										
31	BC21 Power Smart Phase 2	#17966	0	0	0	0	0	0	0	0

BC GAS UTILITY LTD.

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION (CONT'D)
FOR THE YEAR ENDING DECEMBER 31, 2003
($000)

Line No.	Particulars	Account	Projected Balance 12/31/2002	Gross Additions	Less- Taxes	Net Additions	Amortization Expense	Amortization Other	Balance 12/31/2003	Mid-Year Average 2003
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
32	Coastal Facilities (#C-6-95)									
33	- Relocation	#17951	1,159	0	0	0	(232)	0	927	1,043
34	- Extraordinary Plant Loss - Lochburn	#17998	8	0	0	0	(2)	0	6	7
35	- Fraser Valley NBV Amortization	#17996	632	0	0	0	(213)	0	419	526
36	- Noncapital Finance Costs	#17984	764	0	0	0	(153)	0	611	688
37										
38	Organizational Restructuring	#17953	0	0	0	0	0	0	0	0
39	ROE Hearing Costs	#17985	0	0	0	0	0	0	0	0
40										
41	ABC T-Service	#17983	0	0	0	0	0	0	0	0
42	ABC T Project Requirements Phase	#17918	60	0	0	0	(30)	0	30	45
43	Burrard Thermal	#17978	0	0	0	0	0	0	0	0
44	Burner Tip Service	#17972	(100)	0	0	0	100	0	0	(50)
45	Earnings Sharing Mechanism	#17982	294	0	0	0	(98)	0	196	245
46										
47	Salmon Arm Reinforcement	#17990	68	0	0	0	(68)	0	0	34
48	NGV Compression Equip. Recovery	#17992	1,491	0	0	0	(213)	0	1,278	1,385
49	2001 Rate Design	#17974	230	0	0	0	(115)	0	115	173
50										
51	Overheads Change - Income Tax Refund	#17995	(692)	0	0	0	138	0	(554)	(623)
52	CIAOC Software Tax Savings/OH Change	#17995	(4,039)	0	0	0	808	0	(3,231)	(3,635)
53	Other Post Employment Benefits	#17991/93	(5,019)	(5,544)	2,024	(3,520)	0	0	(8,539)	(6,779)
54										
55	Deferred 2000 SCP Cost of Service	#17997	318	0	0	0	(64)	0	254	286
56	SCP Net Mitigation Revenues	#17912	(3,564)	0	0	0	713	0	(2,851)	(3,208)
57	SCP West to East Transmission	#17913	1,962	0	0	0	(392)	0	1,570	1,766
58										
59	CCT Deferral	#17924	(664)	0	0	0	133	0	(531)	(598)
60										
61										
62										
63	Total Deferred Charges for Rate Base		$52,430	($3,519)	$1,284	($2,235)	$254	($39,793)	$10,656	$31,546

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDING DECEMBER 31, 2004
($000)

Line No.	Particulars	Account	Forecast Balance 12/31/2003	Gross Additions	Less- Taxes	Net Additions	Amortization Expense	Amortization Other	Balance 12/31/2004	Mid-Year Average 2004
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Deferred Interest	#17904	($2,718)	$0	$0	$0	$1,359	$0	($1,359)	($2,039)
2										
3	Market Rebate Incentive									
4	- Water Heater Grants	#17909	8	0	0	0	(8)	0	0	4
5										
6	NGV Conversion Grants	#17977	628	725	(250)	475	(145)	0	958	792
7										
8	Local Gas Development	#17910	0	0	0	0	0	0	0	0
9	Fraser Valley Gas Exploration	#17928	0	0	0	0	0	0	0	0
10										
11	Revenue Req. Hearing - 1998-2002	#17960	0	0	0	0	0	0	0	0
12	2003 Revenue Requirement / PBR Multi Yr		147	0	0	0	(37)	0	110	129
13										
14	Demand Side Management	#17916	2,155	1,500	(518)	982	(902)	0	2,235	2,195
15	DSM DRIA	#17961	(100)	0	0	0	50	0	(50)	(75)
16										
17										
18	Tax Deferral (Property, Fed. & Prov.)	#17915	0	0	0	0	0	0	0	0
19	Westar Receivable	#17919	0	0	0	0	0	0	0	(1)
20										
21	G.C.R.A.	#17926	0	0	0	0	0	0	0	0
22	G.C.R.A. Interest	#17973	0	0	0	0	0	0	0	0
23	RSAM	#17927	20,365	0	0	0	0	(10,182)	10,183	15,274
24										
25	Buy/Sell Operating Costs	#17930	0	0	0	0	0	0	0	0
26	Revelstoke Propane Cost	#27902	0	0	0	0	0	0	0	0
27										
28	B.C. Hydro Service Agreement Costs	#17963	471	0	0	0	(471)	0	0	236
29	Recovery of Non-Utility Service	#27904	0	0	0	0	0	0	0	0
30										
31	BC21 Power Smart Phase 2	#17966	0	0	0	0	0	0	0	0

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION (CONT'D)
FOR THE YEAR ENDING DECEMBER 31, 2004
($000)

Line No.	Particulars	Account	Balance 12/31/2003	Gross Additions	Less- Taxes	Net Additions	Amortization Expense	Amortization Other	Balance 12/31/2004	Mid-Year Average 2004
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
32	Coastal Facilities (#C-6-95)									
33	- Relocation	#17951	927	0	0	0	(232)	0	695	811
34	- Extraordinary Plant Loss - Lochburn	#17998	6	0	0	0	(2)	0	4	5
35	- Fraser Valley NBV Amortization	#17996	419	0	0	0	(213)	0	206	313
36	- Noncapital Finance Costs	#17984	611	0	0	0	(153)	0	458	535
37										
38	Organizational Restructuring	#17953	0	0	0	0	0	0	0	0
39	ROE Hearing Costs	#17985	0	0	0	0	0	0	0	0
40										
41	ABC T-Service	#17983	0	0	0	0	0	0	0	0
42	ABC T Project Requirements Phase	#17918	30	0	0	0	(30)	0	0	15
43	Burrard Thermal	#17978	0	0	0	0	0	0	0	0
44	Burner Tip Service	#17972	0	0	0	0	0	0	0	0
45	Earnings Sharing Mechanism	#17982	196	0	0	0	(98)	0	98	147
46										
47	Salmon Arm Reinforcement	#17990	0	0	0	0	0	0	0	0
48	NGV Compression Equip. Recovery	#17992	1,278	0	0	0	(213)	0	1,065	1,172
49	2001 Rate Design	#17974	115	0	0	0	(115)	0	0	58
50										
51	Overheads Change - Income Tax Refund	#17995	(554)	0	0	0	138	0	(416)	(485)
52	CIAOC Software Tax Savings/OH Change	#17995	(3,231)	0	0	0	808	0	(2,423)	(2,827)
53	Other Post Employment Benefits	#17991/93	(8,539)	(5,717)	1,972	(3,745)	0	0	(12,284)	(10,412)
54										
55	Deferred 2000 SCP Cost of Service	#17997	254	0	0	0	(64)	0	190	222
56	SCP Net Mitigation Revenues	#17912	(2,851)	0	0	0	713	0	(2,138)	(2,495)
57	SCP West to East Transmission	#17913	1,570	0	0	0	(392)	0	1,178	1,374
58										
59	CCT Deferral	#17924	(531)	0	0	0	133	0	(398)	(465)
60										
61										
62										
63	Total Deferred Charges for Rate Base		$10,656	($3,492)	$1,204	($2,288)	$126	($10,182)	($1,688)	$4,483

BC GAS UTILITY LTD.

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDING DECEMBER 31, 2005
($000)

Line No.	Particulars	Account	Forecast Balance 12/31/2004	Gross Additions	Less-Taxes	Net Additions	Amortization Expense	Amortization Other	Balance 12/31/2005	Mid-Year Average 2005
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Deferred Interest	#17904	($1,359)	$0	$0	$0	$1,359	$0	$0	($680)
2										
3	Market Rebate Incentive									
4	- Water Heater Grants	#17909	0	0	0	0	0	0	0	0
5										
6	NGV Conversion Grants	#17977	958	800	(276)	524	(240)	0	1,242	1,100
7										
8	Local Gas Development	#17910	0	0	0	0	0	0	0	0
9	Fraser Valley Gas Exploration	#17928	0	0	0	0	0	0	0	0
10										
11	Revenue Req. Hearing - 1998-2002	#17960	0	0	0	0	0	0	0	0
12	2003 Revenue Requirement / PBR Multi Y		110	0	0	0	(37)	0	73	92
13										
14	Demand Side Management	#17916	2,235	1,500	(518)	982	(969)	0	2,248	2,242
15	DSM DRIA	#17961	(50)	0	0	0	50	0	0	(25)
16										
17										
18	Tax Deferral (Property, Fed. & Prov.)	#17915	0	0	0	0	0	0	0	0
19	Westar Receivable	#17919	0	0	0	0	0	0	0	0
20										
21	G.C.R.A.	#17926	0	0	0	0	0	0	0	0
22	G.C.R.A. Interest	#17973	0	0	0	0	0	0	0	0
23	RSAM	#17927	10,183	0	0	0	0	(10,183)	0	5,092
24										
25	Buy/Sell Operating Costs	#17930	0	0	0	0	0	0	0	0
26	Revelstoke Propane Cost	#27902	0	0	0	0	0	0	0	0
27										
28	B.C. Hydro Service Agreement Costs	#17963	0	0	0	0	0	0	0	0
29	Recovery of Non-Utility Service	#27904	0	0	0	0	0	0	0	0
30										
31	BC21 Power Smart Phase 2	#17966	0	0	0	0	0	0	0	0

BC GAS UTILITY LTD.

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION (CONT'D)
FOR THE YEAR ENDING DECEMBER 31, 2005
($000)

Line No.	Particulars	Account	Balance 12/31/2004	Gross Additions	Less-Taxes	Net Additions	Amortization Expense	Amortization Other	Balance 12/31/2005	Mid-Year Average 2005
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
32	Coastal Facilities (#C-6-95)									
33	- Relocation	#17951	695	0	0	0	(232)	0	463	579
34	- Extraordinary Plant Loss - Lochburn	#17998	4	0	0	0	(2)	0	2	3
35	- Fraser Valley NBV Amortization	#17996	206	0	0	0	(206)	0	0	103
36	- Noncapital Finance Costs	#17984	458	0	0	0	(153)	0	305	382
37										
38	Organizational Restructuring	#17953	0	0	0	0	0	0	0	0
39	ROE Hearing Costs	#17985	0	0	0	0	0	0	0	0
40										
41	ABC T-Service	#17983	0	0	0	0	0	0	0	0
42	ABC T Project Requirements Phase	#17918	0	0	0	0	0	0	0	0
43	Burrard Thermal	#17978	0	0	0	0	0	0	0	0
44	Burner Tip Service	#17972	0	0	0	0	0	0	0	0
45	Earnings Sharing Mechanism	#17982	98	0	0	0	(98)	0	0	49
46										
47	Salmon Arm Reinforcement	#17990	0	0	0	0	0	0	0	0
48	NGV Compression Equip. Recovery	#17992	1,065	0	0	0	(213)	0	852	959
49	2001 Rate Design	#17974	0	0	0	0	0	0	0	0
50										
51	Overheads Change - Income Tax Refund	#17995	(416)	0	0	0	138	0	(278)	(347)
52	CIAOC Software Tax Savings/OH Change	#17995	(2,423)	0	0	0	808	0	(1,615)	(2,019)
53	Other Post Employment Benefits	#17991/93	(12,284)	(5,909)	2,039	(3,870)	0	0	(16,154)	(14,219)
54										
55	Deferred 2000 SCP Cost of Service	#17997	190	0	0	0	(64)	0	126	158
56	SCP Net Mitigation Revenues	#17912	(2,138)	0	0	0	713	0	(1,425)	(1,782)
57	SCP West to East Transmission	#17913	1,178	0	0	0	(392)	0	786	982
58										
59	CCT Deferral	#17924	(398)	0	0	0	133	0	(265)	(332)
60										
61										
62										
63	Total Deferred Charges for Rate Base		($1,688)	($3,609)	$1,245	($2,364)	$595	($10,183)	($13,640)	($7,663)

BC GAS UTILITY LTD.

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDING DECEMBER 31, 2006
($000)

Line No.	Particulars	Account	Forecast Balance 12/31/2005	Gross Additions	Less-Taxes	Net Additions	Amortization Expense	Amortization Other	Balance 12/31/2006	Mid-Year Average 2006
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Deferred Interest	#17904	$0	$0	$0	$0	$0	$0	$0	$0
2										
3	Market Rebate Incentive									
4	- Water Heater Grants	#17909	0	0	0	0	0	0	0	0
5										
6	NGV Conversion Grants	#17977	1,242	950	(328)	622	(345)	0	1,519	1,381
7										
8	Local Gas Development	#17910	0	0	0	0	0	0	0	0
9	Fraser Valley Gas Exploration	#17928	0	0	0	0	0	0	0	0
10										
11	Revenue Req. Hearing - 1998-2002	#17960	0	0	0	0	0	0	0	0
12	2003 Revenue Requirement / PBR Multi Yr		73	0	0	0	(37)	0	36	55
13										
14	Demand Side Management	#17916	2,248	1,500	(518)	982	(971)	0	2,259	2,254
15	DSM DRIA	#17961	0	0	0	0	0	0	0	0
16										
17										
18	Tax Deferral (Property, Fed. & Prov.)	#17915	0	0	0	0	0	0	0	0
19	Westar Receivable	#17919	0	0	0	0	0	0	0	0
20										
21	G.C.R.A.	#17926	0	0	0	0	0	0	0	0
22	G.C.R.A. Interest	#17973	0	0	0	0	0	0	0	0
23	RSAM	#17927	0	0	0	0	0	0	0	0
24										
25	Buy/Sell Operating Costs	#17930	0	0	0	0	0	0	0	0
26	Revelstoke Propane Cost	#27902	0	0	0	0	0	0	0	0
27										
28	B.C. Hydro Service Agreement Costs	#17963	0	0	0	0	0	0	0	0
29	Recovery of Non-Utility Service	#27904	0	0	0	0	0	0	0	0
30										
31	BC21 Power Smart Phase 2	#17966	0	0	0	0	0	0	0	0

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION (CONT'D)
FOR THE YEAR ENDING DECEMBER 31, 2006
($000)

Line No.	Particulars	Account	Balance 12/31/2005	Gross Additions	Less- Taxes	Net Additions	Amortization Expense	Amortization Other	Balance 12/31/2006	Mid-Year Average 2006
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
32	Coastal Facilities (#C-6-95)									
33	- Relocation	#17951	463	0	0	0	(232)	0	231	346
34	- Extraordinary Plant Loss - Lochburn	#17998	2	0	0	0	(2)	0	0	1
35	- Fraser Valley NBV Amortization	#17996	0	0	0	0	0	0	0	0
36	- Noncapital Finance Costs	#17984	305	0	0	0	(153)	0	152	229
37										
38	Organizational Restructuring	#17953	0	0	0	0	0	0	0	0
39	ROE Hearing Costs	#17985	0	0	0	0	0	0	0	0
40										
41	ABC T-Service	#17983	0	0	0	0	0	0	0	0
42	ABC T Project Requirements Phase	#17918	0	0	0	0	0	0	0	0
43	Burrard Thermal	#17978	0	0	0	0	0	0	0	0
44	Burner Tip Service	#17972	0	0	0	0	0	0	0	0
45	Earnings Sharing Mechanism	#17982	0	0	0	0	0	0	0	0
46										
47	Salmon Arm Reinforcement	#17990	0	0	0	0	0	0	0	0
48	NGV Compression Equip. Recovery	#17992	852	0	0	0	(213)	0	639	746
49	2001 Rate Design	#17974	0	0	0	0	0	0	0	0
50										
51	Overheads Change - Income Tax Refund	#17995	(278)	0	0	0	138	0	(140)	(209)
52	CIAOC Software Tax Savings/OH Change	#17995	(1,615)	0	0	0	808	0	(807)	(1,211)
53	Other Post Employment Benefits	#17991/93	(16,154)	(6,107)	2,107	(4,000)	0	0	(20,154)	(18,154)
54										
55	Deferred 2000 SCP Cost of Service	#17997	126	0	0	0	(64)	0	62	94
56	SCP Net Mitigation Revenues	#17912	(1,425)	0	0	0	713	0	(712)	(1,069)
57	SCP West to East Transmission	#17913	786	0	0	0	(392)	0	394	590
58										
59	CCT Deferral	#17924	(265)	0	0	0	133	0	(132)	(199)
60										
61										
62										
63	Total Deferred Charges for Rate Base		($13,640)	($3,657)	$1,261	($2,396)	($617)	$0	($16,653)	($15,146)

BC GAS UTILITY LTD.

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDING DECEMBER 31, 2007
($000)

Line No.	Particulars	Account	Forecast Balance 12/31/2006	Gross Additions	Less-Taxes	Net Additions	Amortization Expense	Amortization Other	Balance 12/31/2007	Mid-Year Average 2006
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Deferred Interest	#17904	$0	$0	$0	$0	$0	$0	$0	$0
2										
3	Market Rebate Incentive									
4	- Water Heater Grants	#17909	0	0	0	0	0	0	0	0
5										
6	NGV Conversion Grants	#17977	1,519	1,200	(414)	786	(451)	0	1,854	1,687
7										
8	Local Gas Development	#17910	0	0	0	0	0	0	0	0
9	Fraser Valley Gas Exploration	#17928	0	0	0	0	0	0	0	0
10										
11	Revenue Req. Hearing - 1998-2002	#17960	0	0	0	0	0	0	0	0
12	2003 Revenue Requirement / PBR Multi Yr		36	0	0	0	(36)	0	0	18
13										
14	Demand Side Management	#17916	2,259	1,500	(518)	982	(981)	0	2,260	2,260
15	DSM DRIA	#17961	0	0	0	0	0	0	0	0
16										
17										
18	Tax Deferral (Property, Fed. & Prov.)	#17915	0	0	0	0	0	0	0	0
19	Westar Receivable	#17919	0	0	0	0	0	0	0	0
20										
21	G.C.R.A.	#17926	0	0	0	0	0	0	0	0
22	G.C.R.A. Interest	#17973	0	0	0	0	0	0	0	0
23	RSAM	#17927	0	0	0	0	0	0	0	0
24										
25	Buy/Sell Operating Costs	#17930	0	0	0	0	0	0	0	0
26	Revelstoke Propane Cost	#27902	0	0	0	0	0	0	0	0
27										
28	B.C. Hydro Service Agreement Costs	#17963	0	0	0	0	0	0	0	0
29	Recovery of Non-Utility Service	#27904	0	0	0	0	0	0	0	0
30										
31	BC21 Power Smart Phase 2	#17966	0	0	0	0	0	0	0	0

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION (CONT'D)
FOR THE YEAR ENDING DECEMBER 31, 2007
($000)

Line No.	Particulars	Account	Balance 12/31/2006	Gross Additions	Less- Taxes	Net Additions	Amortization Expense	Amortization Other	Balance 12/31/2007	Mid-Year Average 2007
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
32	Coastal Facilities (#C-6-95)									
33	- Relocation	#17951	231	0	0	0	(231)	0	0	116
34	- Extraordinary Plant Loss - Lochburn	#17998	0	0	0	0	0	0	0	0
35	- Fraser Valley NBV Amortization	#17996	0	0	0	0	0	0	0	0
36	- Noncapital Finance Costs	#17984	152	0	0	0	(152)	0	0	76
37										
38	Organizational Restructuring	#17953	0	0	0	0	0	0	0	0
39	ROE Hearing Costs	#17985	0	0	0	0	0	0	0	0
40										
41	ABC T-Service	#17983	0	0	0	0	0	0	0	0
42	ABC T Project Requirements Phase	#17918	0	0	0	0	0	0	0	0
43	Burrard Thermal	#17978	0	0	0	0	0	0	0	0
44	Burner Tip Service	#17972	0	0	0	0	0	0	0	0
45	Earnings Sharing Mechanism	#17982	0	0	0	0	0	0	0	0
46										
47	Salmon Arm Reinforcement	#17990	0	0	0	0	0	0	0	0
48	NGV Compression Equip. Recovery	#17992	639	0	0	0	(213)	0	426	533
49	2001 Rate Design	#17974	0	0	0	0	0	0	0	0
50										
51	Overheads Change - Income Tax Refund	#17995	(140)	0	0	0	140	0	0	(70)
52	CIAOC Software Tax Savings/OH Change	#17995	(807)	0	0	0	807	0	0	(404)
53	Other Post Employment Benefits	#17991/93	(20,154)	(6,312)	2,178	(4,134)	0	0	(24,288)	(22,221)
54										
55	Deferred 2000 SCP Cost of Service	#17997	62	0	0	0	(62)	0	0	31
56	SCP Net Mitigation Revenues	#17912	(712)	0	0	0	712	0	0	(356)
57	SCP West to East Transmission	#17913	394	0	0	0	(394)	0	0	197
58										
59	CCT Deferral	#17924	(132)	0	0	0	132	0	0	(66)
60										
61										
62										
63	Total Deferred Charges for Rate Base		($16,653)	($3,612)	$1,246	($2,366)	($729)	$0	($19,748)	($18,199)

BC GAS UTILITY LTD.
PRELIMINARY
UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDED DECEMBER 31, 2001
($000)

Line No.	Particulars	Account	Recorded Balance 12/31/2000	Gross Additions	Less- Taxes	Net Additions	Amortization Expense	Amortization Other	Balance 12/31/2001	Mid-Year Average 2001
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Deferred Interest	#17904	($977)	($4,087)	$0	($4,087)	$987	$0	($4,077)	($2,527)
2										
3	Market Rebate Incentive									
4	- Water Heater Grants	#17909	136	0	0	0	(62)	0	74	105
5										
6	NGV Conversion Grants	#17977	208	161	(70)	91	(98)	0	201	205
7										
8	Local Gas Development	#17910	1,035	0	(65)	(65)	(554)	0	416	726
9	Fraser Valley Gas Exploration	#17928	183	0	0	0	(91)	0	92	138
10										
11	Revenue Req. Hearing - 1998-2002	#17960	28	9	(4)	5	(21)	0	12	20
12	2003 Revenue Requirement / PBR Multi Y		0	0	0	0	0	0	0	0
13										
14	Demand Side Management	#17916	1,181	1,379	(600)	779	(306)	0	1,654	1,418
15	Demand Side Management DRIA	#17961	(227)	0	0	0	77	0	(150)	(189)
16	Integrated Resource Plan	#17917	0	0	0	0	0	0	0	0
17										
18	Tax Deferral (Property, Fed. & Prov.)	#17915	0	0	0	0	0	0	0	0
19	Westar Receivable	#17919	54	0	0	0	(27)	0	27	41
20										
21	G.C.R.A. (see Page 5.17, Note 1)	#17926	88,301	0	0	0	0	(29,434)	58,867	73,583
22	G.C.R.A. Interest	#17973	719	1,569	0	1,569	0	(369)	1,919	1,319
23	RSAM	#17927	12,674	29,518	(9,485)	20,033	0	(2,957)	29,750	21,212
24										
25	Buy/Sell Operating Costs	#17930	17	0	0	0	0	0	17	17
26	Revelstoke Propane Cost	#27902	247	(185)	81	(104)	0	0	143	195
27										
28	B.C. Hydro Service Agreement Costs	#17963	(341)	1,669	(726)	943	341	0	943	301
29	Recovery of Non-Utility Service	#27904	0	0	0	0	0	0	0	0
30										
31	BC21 Power Smart Program	#17966	66	0	0	0	(34)	0	32	49

BC GAS UTILITY LTD.
PRELIMINARY
UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION (CONT'D)
FOR THE YEAR ENDING DECEMBER 31, 2001
($000)

Line No.	Particulars	Account	Recorded Balance 12/31/2000	Gross Additions	Less- Taxes	Net Additions	Amortization Expense	Amortization Other	Balance 12/31/2001	Mid-Year Average 2001
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
32	Coastal Facilities									
33	- Relocation	#17951	2,059	544	(237)	307	(702)	0	1,664	1,862
34	- Extraordinary Plant Loss Lochburn	#17998	0	5	0	5	0	0	5	2
35	- Fraser Valley NBV Amortization	#17996	1,058	0	0	0	(213)	0	845	952
36	- Noncapital Finance Costs	#17984	718	32	(14)	18	0	0	736	727
37										
38	Organizational Restructuring	#17953	192	0	0	0	(96)	0	96	144
39	ROE Hearing Costs	#17985	87	2	(1)	1	(83)	0	5	46
40										
41	ABC T-Service	#17983	59	3	(1)	2	(62)	0	(1)	29
42	ABC T Project Requirements Phase	#17918	0	106	(46)	60	0	0	60	30
43	Burrard Thermal	#17978	(17)	0	0	0	17	0	0	(9)
44	Burner Tip Service	#17972	(105)	(176)	76	(100)	108	0	(97)	(101)
45	Earnings Sharing Mechanism (see Note 1)	#17982	(4,289)	0	0	0	0	4,217	(72)	(2,181)
46										
47	Salmon Arm Reinforcement	#17990	202	0	0	0	(67)	0	135	169
48	NGV Compression Equip. Recovery	#17992	1,917	0	0	0	(213)	0	1,704	1,811
49	2001 Rate Design	#17974	349	(58)	25	(33)	0	0	316	333
50										
51	Overheads Change - Income Tax Refund	#17995	(13,053)	(23)	0	(23)	0	12,384	(692)	(6,873)
52	CIAOC Software Tax Savings/OH Change	#17995	(4,039)	0	0	0	0	0	(4,039)	(4,039)
53	Other Post Employment Benefits	#17991/93	135	(4,092)	1,780	(2,312)	0	0	(2,177)	(1,021)
54										
55	Deferred 2000 SCP Cost of Service	#17997	374	(100)	44	(56)	0	0	318	346
56	SCP Net Mitigation Revenues	#17912	0	(9,535)	4,148	(5,387)	0	0	(5,387)	(2,694)
57	SCP West to East Transmission	#17913	0	1,529	(665)	864	0	0	864	432
58										
59	CCT Deferral	#17924	0	(1,176)	512	(664)	0	0	(664)	(332)
60										
61										
62										
63	Total Deferred Charges for Rate Base		$88,951	$17,094	($5,248)	$11,846	($1,099)	($16,159)	$83,539	$86,246
64										
65	1) Deferred Charges Not In Dec. 31, 2001 Rate Base									
66	GCRA Variance #17926: Dec. 31, 2001 Actual to 2001 Test Year ($85,483 - $58,867 = $26,616)								26,616	
67	GCRA Variance #17926: 2002 Gas Cost Flow-through to Dec. 31, 2001 Actual ($72,877 - $85,483 = $-12,606)								(12,606)	
68	2001 Earnings Sharing Mechanism adjustment to actual included in rate base in 2002								(550)	
69	Jan. 1, 2002 Total Deferred Charges for Rate Base								$96,999	

BC GAS UTILITY LTD.
PROJECTION
UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION
FOR THE YEAR ENDING DECEMBER 31, 2002
($000)

Line No.	Particulars	Account	Preliminary Balance 12/31/2001	Gross Additions	Less- Taxes	Net Additions	Amortization Expense	Amortization Other	Balance 12/31/2002	Mid-Year Average 2002
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Deferred Interest	#17904	($4,077)	$0	$0	$0	$0	$0	($4,077)	($4,077)
2										
3	Market Rebate Incentive									
4	- Water Heater Grants	#17909	74	0	0	0	(43)	0	31	53
5										
6	NGV Conversion Grants	#17977	201	490	(189)	301	(129)	0	373	287
7										
8	Local Gas Development	#17910	416	0	(59)	(59)	(357)	0	0	208
9	Fraser Valley Gas Exploration	#17928	92	0	0	0	(92)	0	0	46
10										
11	Revenue Req. Hearing - 1998-2002	#17960	12	0	0	0	(12)	0	0	6
12	2003 Revenue Requirement / PBR Multi Y		0	300	(116)	184	0	0	184	92
13										
14	Demand Side Management	#17916	1,654	1,585	(610)	975	(569)	0	2,060	1,857
15	Demand Side Management DRIA	#17961	(150)	0	0	0	0	0	(150)	(150)
16	Integrated Resource Plan	#17917	0	0	0	0	0	0	0	0
17										
18	Tax Deferral (Property, Fed. & Prov.)	#17915	0	0	0	0	0	0	0	0
19	Westar Receivable	#17919	27	0	0	0	(27)	0	0	14
20										
21	G.C.R.A.	#17926	72,877	0	0	0	0	(43,934)	28,943	50,909
22	G.C.R.A. Interest	#17973	1,919	0	0	0	0	(1,251)	668	1,294
23	RSAM	#17927	29,750	13,220	(5,090)	8,130	0	(7,333)	30,547	30,149
24										
25	Buy/Sell Operating Costs	#17930	17	0	0	0	(17)	0	0	9
26	Revelstoke Propane Cost	#27902	143	(233)	90	(143)	0	0	0	72
27										
28	B.C. Hydro Service Agreement Costs	#17963	943	0	0	0	0	0	943	943
29	Recovery of Non-Utility Service	#27904	0	0	0	0	0	0	0	0
30										
31	BC21 Power Smart Phase 2	#17966	32	0	0	0	(32)	0	0	16

($000)

Line No.	Particulars	Account	Preliminary Balance 12/31/2001	Gross Additions	Less- Taxes	Net Additions	Amortization Expense	Amortization Other	Balance 12/31/2002	Mid-Year Average 2002
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
32	Coastal Facilities									
33	- Relocation	#17951	1,664	0	0	0	(505)	0	1,159	1,412
34	- Extraordinary Plant Loss - Lochburn	#17998	5	3	0	3	0	0	8	6
35	- Fraser Valley NBV Amortization	#17996	845	0	0	0	(213)	0	632	739
36	- Noncapital Finance Costs	#17984	736	45	(17)	28	0	0	764	750
37										
38	Organizational Restructuring	#17953	96	0	0	0	(96)	0	0	48
39	ROE Hearing Costs	#17985	5	0	0	0	(5)	0	0	3
40										
41	ABC T-Service	#17983	(1)	0	0	0	1	0	0	(1)
42	ABC T Project Requirements Phase	#17918	60	0	0	0	0	0	60	60
43	Burrard Thermal	#17978	0	0	0	0	0	0	0	0
44	Burner Tip Service	#17972	(97)	(5)	2	(3)	0	0	(100)	(99)
45	Earnings Sharing Mechanism	#17982	(622)	0	0	0	0	916	294	(164)
46										
47	Salmon Arm Reinforcement	#17990	135	0	0	0	(67)	0	68	102
48	NGV Compression Equip. Recovery	#17992	1,704	0	0	0	(213)	0	1,491	1,598
49	2001 Rate Design	#17974	316	31	(12)	19	(105)	0	230	273
50										
51	Overheads Change - Income Tax Refund	#17995	(692)	0	0	0	0	0	(692)	(692)
52	CIAOC Software Tax Savings/OH Change	#17995	(4,039)	0	0	0	0	0	(4,039)	(4,039)
53	Other Post Employment Benefits	#17991/93	(2,177)	(4,621)	1,779	(2,842)	0	0	(5,019)	(3,598)
54										
55	Deferred 2000 SCP Cost of Service	#17997	318	0	0	0	0	0	318	318
56	SCP Net Mitigation Revenues	#17912	(5,387)	2,964	(1,141)	1,823	0	0	(3,564)	(4,476)
57	SCP West to East Transmission	#17913	864	1,785	(687)	1,098	0	0	1,962	1,413
58										
59	CCT Deferral	#17924	(664)	0	0	0	0	0	(664)	(664)
60										
61										
62										
63	Total Deferred Charges for Rate Base		$96,999	$15,564	($6,050)	$9,514	($2,481)	($51,602)	$52,430	$74,717

BC GAS UTILITY LTD.
FORECAST ACCUMULATED DEPRECIATION
FOR THE YEARS ENDING DECEMBER 31, 2003 TO 2007

Accumulated Depreciation for 2003 is based on the 2001 actual closing balance plus a projection of 2002 additions to accumulated depreciation, retirements, and retirement costs. BCUC-approved depreciation rates and amortization periods are used for all accounts other than where specific changes are requested. A discussion of the proposed depreciation changes can be found in Section E.

BC GAS UTILITY LTD.

ACCUMULATED DEPRECIATION
FOR THE YEARS ENDING DECEMBER 31, 2001 TO 2007
($000)

Line No.	Particulars	Preliminary 2001	Projected 2002	Forecast 2003	Forecast 2004	Forecast 2005	Forecast 2006	Forecast 2007	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	Balance, Beginning	$396,495	$444,256	$501,221	$567,822	$635,142	$708,168	$747,397	- Tab 4, Pages 3.2 - 8.2
2									
3	CIAOC Amortization Balance, Beginning	(20,495)	(25,822)	(33,228)	(40,820)	(49,159)	(53,007)	(56,350)	- Tab 3, Pages 4.1, 4.2, 4.3
4									
5	Gas Plant Held for Future Use								
6	Balance, Beginning	0	0	0	0	0	0	0	
7									
8	Retirement Work in Progress	0	0	0	0	0	0	0	
9									
10	Utility Accumulated Depreciation								
11	Balance, Beginning	376,000	418,434	467,993	527,002	585,983	655,161	691,047	
12									
13	Depreciation Provision								
14	Total Plant	$75,103	76,612	81,492	90,192	92,586	95,976	95,479	- Tab 4, Pages 3.2 - 8.2
15	Less - Gas Plant Held for Future Use	0	0	0	0	0	0	0	
16									
17	Less - Amortization of Contributions in								
18	Aid of Construction	(6,295)	(7,406)	(8,587)	(10,519)	(10,860)	(10,598)	(10,521)	- Tab 3, Pages 4.1, 4.2, 4.3
19									
20		68,808	69,206	72,905	79,673	81,726	85,378	84,958	
21									
22	Plant Retirements	($24,763)	(18,085)	($12,072)	($18,959)	($10,755)	($47,649)	($5,463)	- Tab 4, Pages 3.2 - 8.2
23									
24	Removal Costs	(3,323)	(1,770)	(1,946)	(1,859)	(1,922)	(1,974)	(2,046)	- Tab 4, Pages 3.2 - 8.2
25									
26	Proceeds on Disposal	77	208	122	126	129	131	134	- Tab 4, Pages 3.2 - 8.2
27									
28		(28,009)	(19,647)	(13,896)	(20,692)	(12,548)	(49,492)	(7,375)	
29									
30	Balance, Ending	$416,799	$467,993	$527,002	$585,983	$655,161	$691,047	$768,630	- Tab 2, Pages 1, 1.1, 1.2

DEPRECIATION AND AMORTIZATION WORKSHEET
FOR THE YEAR ENDING DECEMBER 31, 2003
($000)

Line No.	Account	Balance 12/31/2002	Annual Depreciation Rate %	Provision 2003 (Cr.)	Adjust-ments	Retirements	Retirement Costs	Proceeds on Disposal	Accumulated 12/31/2002	Accumulated 12/31/2003
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	117-00 Utility Plant Acquisition Adj.	$0	1.00%	$0	$0	$0	$0	$0	$0	$0
2	175-00 Unamortized Conversion Expense	109	1.00%	1	0	0	0	0	44	45
3	178-00 Organization Expense	728	1.00%	7	0	0	0	0	319	326
4	179-01 Other Deferred Charges	0	1.00%	0	0	0	0	0	0	0
5	401-00 Franchise and Consents	99	1.00%	1	0	0	0	0	43	44
6	402-00 Utility Plant Acquisition Adjustment	63	1.00%	1	0	0	0	0	23	24
7	402-00 Other Intangible Plant - Lease	85	Lease	1	0	0	0	0	70	71
8		1,084		11	0	0	0	0	499	510
9										
10	**GAS PLANT HELD FOR FUTURE USE**									
11	492-00 Structures & Improvements									
12	- Frame Buildings	0	3.00%	0	0	0	0	0	0	0
13	- Masonry Buildings	0	1.50%	0	0	0	0	0	0	0
14	492-00 Manufacturing Equipment	0	3.00%	0	0	0	0	0	0	0
15	492-00 Gas Holder	0	2.00%	0	0	0	0	0	0	0
16	492-00 Compressor Equip/Commun. Equip.	0	5.00%	0	0	0	0	0	0	0
17	492-00 Gas Plant Held for Future Use	0	0.00%	0	0	0	0	0	0	0
18		0		0	0	0	0	0	0	0
19										
20	**MANUFACTURED GAS / LOCAL STORAGE PLANT**									
21	432 Manufact'd Gas - Struct. & Improvements									
22	- Frame Buildings	0	3.00%	0	0	0	0	0	0	0
23	- Masonry Buildings	413	1.50%	6	0	0	0	0	69	75
24	433 Manufacturing Equipment	269	3.00%	8	0	0	0	0	22	30
25	434 Gas Holders - Manufacturing	353	2.00%	7	0	0	0	0	123	130
26	436 Compressor Equipment	53	3.00%	1	0	0	0	0	11	12
27	437 Measuring & Regulating	295	3.00%	9	0	0	0	0	87	96
28	442-00 Structures and Improvements	4,264	4.00%	171	0	0	0	0	1,091	1,262
29	443-00 Gas Holders Storage	12,279	4.00%	491	0	0	0	0	5,402	5,893
30	449-00 Local Storage Equipment	16,447	4.00%	658	0	0	0	0	5,180	5,838
31		34,373		1,351	0	0	0	0	11,985	13,336

BC GAS UTILITY LTD.

DEPRECIATION AND AMORTIZATION WORKSHEET (CONT'D)
FOR THE YEAR ENDING DECEMBER 31, 2003
($000)

Line No.	Account	Balance 12/31/2002	Annual Depreciation Rate %	Provision 2003 (Cr.)	Adjust-ments	Retirements	Retirement Costs	Proceeds on Disposal	Accumulated 12/31/2002	Accumulated 12/31/2003
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**TRANSMISSION PLANT**									
2	461-Land Rights - Byron Creek	$0	5.00%	$0	$0	$0	$0	$0	$12	$12
3	462-00 Structures and Improvements									
4	- Compressor Stations	13,228	3.00%	397	0	0	0	0	2,208	2,605
5	463-00 Measuring & Regulating	3,048	3.00%	91	0	0	0	0	559	650
6	464-00 Other Structures - Frame Buildings	4,282	3.00%	128	0	0	0	0	214	342
7	465-00 Mains & Crossings	658,521	2.00%	13,170	0	(742)	(77)	0	94,612	106,963
8	465-00 Mains & Crossings - Byron Creek	885	2.00%	18	0	0	0	0	554	572
9	466-00 Compressor Equipment	105,248	3.00%	3,157	0	0	0	0	13,249	16,406
10	467-00 Measuring & Regulating	19,963	3.00%	599	0	0	0	0	3,525	4,124
11	467-10 Telemetering	5,797	10.00%	580	0	0	0	0	3,384	3,964
12	468-00 Communications Structures & Equip.	1,300	10.00%	130	0	0	0	0	222	352
13	469-00 Other Transmission Equipment	0	5.00%	0	0	0	0	0	0	0
14		812,272		18,270	0	(742)	(77)	0	118,539	135,990
15										
16	**DISTRIBUTION PLANT**									
17	471-Land Rights - Byron Creek	1	0.00%	0	0	0	0	0	1	1
18	472-00 Structures & Improvements									
19	-Leasehold Alterations	0	Term - Lease	0	0	0	0	0	0	0
20	-Frame Buildings	5,954	3.00%	179	0	0	0	0	1,275	1,454
21	-Masonry Buildings	0	1.50%	0	0	0	0	0	0	0
22	-Byron Creek	2	3.00%	0	0	0	0	0	2	2
23	473-00 Services	451,937	2.00%	9,039	0	(2,021)	(1,458)	0	62,167	67,727
24	474-00 House Regulator & Meter Installation	124,686	3.00%	3,741	0	(317)	(186)	2	25,277	28,517
25	475-00 Mains	604,538	2.00%	12,091	0	(2,078)	(194)	0	141,272	151,091
26	476-00 Compressed Natural Gas									
27										
28	-NGV Compressor Equipment	0	5.00%	0	0	0	0	0	0	0
29	-All Other	229	6.67%	15	0	0	0	0	127	142
30	477-00 Measuring & Regulating	46,209	3.00%	1,386	0	(325)	(9)	0	4,985	6,037
31	477-10 Telemetering	5,209	10.00%	521	0	0	0	0	3,382	3,903
32	477-00 Measuring & Regulating - Byron Creek	114	3.00%	3	0	0	0	0	108	111
33	478 Meters	149,536	3.00%	4,486	0	(526)	(22)	120	27,157	31,215
34	479 Other Distribution Equipment	500	4.00%	20	0	0	0	0	0	20
35		1,388,915		31,481	0	(5,267)	(1,869)	122	265,753	290,220

BC GAS UTILITY LTD.

DEPRECIATION AND AMORTIZATION WORKSHEET (CONT'D)
FOR THE YEAR ENDING DECEMBER 31, 2003
($000)

				Provision					Accumulated	
Line No.	Account	Balance 12/31/2002	Annual Depreciation Rate %	2003 (Cr.)	Adjust-ments	Retirements	Retirement Costs	Proceeds on Disposal	12/31/2002	12/31/2003
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**GENERAL PLANT**									
2	482-00 Structures & Improvements									
3	-Leasehold Alterations	$13,343	Term - Lease	$1,913	$0	$0	$0	$0	$10,744	$12,657
4	-Masonry Buildings	21,737	1.50%	326	0	0	0	0	1,692	2,018
5	-Frame Buildings	4,552	3.00%	137	0	0	0	0	(3,640)	(3,503)
6	483-00 Office Furniture & Equipment									
7	-Furniture & Equipment	22,170	5.00%	1,109	0	(12)	0	0	7,266	8,363
8	-Computers - Hardware	22,673	20.00%	4,535	0	(4,708)	0	0	17,385	17,212
9										
10	-Computer Software - Non-Infrastructure	39,227	12.50%	4,903	0	(1,256)	0	0	16,407	20,054
11	-Computer Software - Infrastructure/Custom	86,111	12.50%	10,764	0	(589)	0	0	25,137	35,312
12										
13	484-00 Transportation Equipment	409	15.00%	61	0	(31)	0	0	2,600	2,630
14	485-00 Maintenance & Repair Equipment	12	5.00%	1	0	0	0	0	(364)	(363)
15	486-00 Tools & Work Equipment	23,528	5.00%	1,176	0	(195)	0	0	7,546	8,527
16	487-00 Equipment on Customers' Premises	1,644	5.00%	82	0	0	0	0	531	613
17	487-XX - VRA Compressor	0	10.00%	0	0	0	0	0	0	0
18	487-XX - VRA Compressor Installation Cost	0	33.33%	0	0	0	0	0	288	288
19	488-00 Communication - Structures & Equip.	10,123	5.00%	506	0	(267)	0	0	2,252	2,491
20	488-00 Communication - Radios	4,671	10.00%	467	0	0	0	0	2,375	2,842
21	489-00 Other General Equipment	0	5.00%	0	0	0	0	0	0	0
22		250,200		25,980	0	(7,058)	0	0	90,219	109,141
23										
24	**UNCLASSIFIED PLANT**									
25	498-00 O&M Expense Charged to Construction	199,965	2.20%	4,399	0	0	0	0	14,226	18,625
26										
27	TOTAL	$2,686,809		$81,492	$0	($13,067)	($1,946)	$122	$501,221	$567,822

DEPRECIATION AND AMORTIZATION WORKSHEET
FOR THE YEAR ENDING DECEMBER 31, 2004
($000)

Line No.	Account	Balance 12/31/2003	Annual Depreciation Rate %	Provision 2004 (Cr.)	Adjust-ments	Retirements	Retirement Costs	Proceeds on Disposal	Accumulated 12/31/2003	Accumulated 12/31/2004
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	117-00 Utility Plant Acquisition Adj.	$0	1.00%	$0	$0	$0	$0	$0	$0	$0
2	175-00 Unamortized Conversion Expense	109	1.00%	1	0	0	0	0	45	46
3	178-00 Organization Expense	728	1.00%	7	0	0	0	0	326	333
4	179-01 Other Deferred Charges	0	1.00%	0	0	0	0	0	0	0
5	401-00 Franchise and Consents	99	1.00%	1	0	0	0	0	44	45
6	402-00 Utility Plant Acquisition Adjustment	63	1.00%	1	0	0	0	0	24	25
7	402-00 Other Intangible Plant - Lease	85	Lease Term	1	0	0	0	0	71	72
8		1,084		11	0	0	0	0	510	521
9										
10	**GAS PLANT HELD FOR FUTURE USE**									
11	102-00 Structures & Improvements									
12	- Frame Buildings	0	3.00%	0	0	0	0	0	0	0
13	- Masonry Buildings	0	1.50%	0	0	0	0	0	0	0
14	102-00 Manufacturing Equipment	0	3.00%	0	0	0	0	0	0	0
15	102-00 Gas Holder	0	2.00%	0	0	0	0	0	0	0
16	492-00 Compressor Equip/Commun. Equip.	0	5.00%	0	0	0	0	0	0	0
17	492-00 Gas Plant Held for Future Use	0	0.00%	0	0	0	0	0	0	0
18		0		0	0	0	0	0	0	0
19										
20	**MANUFACTURED GAS / LOCAL STORAGE PLANT**									
21	432 Manufact'd Gas - Struct. & Improvements									
22	- Frame Buildings	0	3.00%	0	0	0	0	0	0	0
23	- Masonry Buildings	413	1.50%	6	0	0	0	0	75	81
24	433 Manufacturing Equipment	269	3.00%	8	0	0	0	0	30	38
25	434 Gas Holders - Manufacturing	353	2.00%	7	0	0	0	0	130	137
26	436 Compressor Equipment	53	3.00%	1	0	0	0	0	12	13
27	437 Measuring & Regulating	295	3.00%	9	0	0	0	0	96	105
28	442-00 Structures and Improvements	4,347	4.00%	174	0	0	0	0	1,262	1,436
29	443-00 Gas Holders Storage	14,114	4.00%	565	0	0	0	0	5,893	6,458
30	449-00 Local Storage Equipment	16,453	4.00%	658	0	0	0	0	5,838	6,496
31		36,297		1,428	0	0	0	0	13,336	14,764

DEPRECIATION AND AMORTIZATION WORKSHEET (CONT'D)
FOR THE YEAR ENDING DECEMBER 31, 2004
($000)

Line No.	Account	Balance 12/31/2003	Annual Depreciation Rate %	Provision 2004 (Cr.)	Provision Adjust-ments	Provision Retirements	Provision Retirement Costs	Provision Proceeds on Disposal	Accumulated 12/31/2003	Accumulated 12/31/2004
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**TRANSMISSION PLANT**									
2	461 Land Rights - Byron Creek	$0	5.00%	$0	$0	$0	$0	$0	$12	$12
3	462-00 Structures and Improvements									
4	- Compressor Stations	13,507	3.00%	405	0	0	0	0	2,605	3,010
5	463-00 Measuring & Regulating	3,048	3.00%	91	0	0	0	0	650	741
6	464-00 Other Structures - Frame Buildings	4,282	3.00%	128	0	0	0	0	342	470
7	465-00 Mains & Crossings	672,625	2.00%	13,453	0	(631)	(79)	0	106,963	119,706
8	465-00 Mains & Crossings - Byron Creek	885	2.00%	18	0	0	0	0	572	590
9	466-00 Compressor Equipment	105,293	3.00%	3,159	0	0	0	0	16,406	19,565
10	467-00 Measuring & Regulating	23,839	3.00%	715	0	0	0	0	4,124	4,839
11	467-10 Telemetering	5,797	10.00%	580	0	0	0	0	3,964	4,544
12	468-00 Communications Structures & Equip.	1,783	10.00%	178	0	0	0	0	352	530
13	469-00 Other Transmission Equipment	0	5.00%	0	0	0	0	0	0	0
14		831,059		18,727	0	(631)	(79)	0	135,990	154,007
15										
16	**DISTRIBUTION PLANT**									
17	471 Land Rights - Byron Creek	1	0.00%	0	0	0	0	0	1	1
18	472-00 Structures & Improvements									
19	-Leasehold Alterations	0	Term - Lease	0	0	0	0	0	0	0
20	-Frame Buildings	6,215	3.00%	186	0	0	0	0	1,454	1,640
21	-Masonry Buildings	0	1.50%	0	0	0	0	0	0	0
22	-Byron Creek	2	3.00%	0	0	0	0	0	2	2
23	473-00 Services	463,389	2.00%	9,268	0	(1,956)	(1,376)	0	67,727	73,663
24	474-00 House Regulator & Meter Installation	130,710	3.57%	4,666	0	(322)	(188)	2	28,517	32,675
25	475-00 Mains	623,244	2.00%	12,465	0	(1,840)	(184)	0	151,091	161,532
26	476-00 Compressed Natural Gas									
27										
28	-NGV Compressor Equipment	0	5.00%	0	0	0	0	0	0	0
29	-All Other	229	6.67%	15	0	0	0	0	142	157
30	477-00 Measuring & Regulating	52,385	3.00%	1,572	0	(315)	(9)	0	6,037	7,285
31	477-10 Telemetering	5,311	10.00%	531	0	0	0	0	3,903	4,434
32	477-00 Measuring & Regulating - Byron Creek	114	3.00%	3	0	0	0	0	111	114
33	478 Meters	159,522	3.57%	5,695	0	(532)	(23)	124	31,215	36,479
34	479 Other Distribution Equipment	500	4.00%	20	0	0	0	0	20	40
35		1,441,622		34,421	0	(4,965)	(1,780)	126	290,220	318,022

BC GAS UTILITY LTD.

DEPRECIATION AND AMORTIZATION WORKSHEET (CONT'D)
FOR THE YEAR ENDING DECEMBER 31, 2004
($000)

Line No.	Account	Balance 12/31/2003	Annual Depreciation Rate %	Provision 2004 (Cr.)	Provision Adjust-ments	Provision Retirements	Provision Retirement Costs	Provision Proceeds on Disposal	Accumulated 12/31/2003	Accumulated 12/31/2004
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**GENERAL PLANT**									
2	482-00 Structures & Improvements									
3	-Leasehold Alterations	$13,950	Term - Lease	$1,943	$0	$0	$0	$0	$12,657	$14,600
4	-Masonry Buildings	21,736	1.50%	326	0	0	0	0	2,018	2,344
5	-Frame Buildings	4,552	3.00%	137	0	0	0	0	(3,503)	(3,366)
6	483-00 Office Furniture & Equipment									
7	-Furniture & Equipment	22,617	5.00%	1,131	0	(20)	0	0	8,363	9,474
8	-Computers - Hardware	24,284	20.00%	4,857	0	(6,459)	0	0	17,212	15,610
9										
10	-Computer Software - Non-Infrastructure	38,821	20.00%	7,764	0	(5,734)	0	0	20,054	22,084
11	-Computer Software - Infrastructure/Custom	96,329	12.50%	12,041	0	(1,871)	0	0	35,312	45,482
12										
13	484-00 Transportation Equipment	419	15.00%	63	0	(261)	0	0	2,630	2,432
14	485-00 Maintenance & Repair Equipment	12	5.00%	1	0	(4)	0	0	(363)	(366)
15	486-00 Tools & Work Equipment	25,417	5.00%	1,271	0	(217)	0	0	8,527	9,581
16	487-00 Equipment on Customers' Premises	1,644	5.00%	82	0	0	0	0	613	695
17	487-XX - VRA Compressor	0	10.00%	0	0	0	0	0	0	0
18	487-XX - VRA Compressor Installation Cost	0	33.33%	0	0	0	0	0	288	288
19	488-00 Communication - Structures & Equip.	10,583	5.00%	529	0	(977)	0	0	2,491	2,043
20	488-00 Communication - Radios	4,913	10.00%	491	0	0	0	0	2,842	3,333
21	489-00 Other General Equipment	0	5.00%	0	0	0	0	0	0	0
22		265,277		30,636	0	(15,543)	0	0	109,141	124,234
23										
24	**UNCLASSIFIED PLANT**									
25	498-00 O&M Expense Charged to Construction	225,844	2.20%	4,969	0	0	0	0	18,625	23,594
26										
27	TOTAL	$2,801,183		$90,192	$0	($21,139)	($1,859)	$126	$567,822	$635,142

DEPRECIATION AND AMORTIZATION WORKSHEET
FOR THE YEAR ENDING DECEMBER 31, 2005
($000)

Line No.	Account	Balance 12/31/2004	Annual Depreciation Rate %	Provision 2005 (Cr.)	Provision Adjust-ments	Provision Retirements	Provision Retirement Costs	Provision Proceeds on Disposal	Accumulated 12/31/2004	Accumulated 12/31/2005
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	117-00 Utility Plant Acquisition Adj.	$0	1.00%	$0	$0	$0	$0	$0	$0	$0
2	175-00 Unamortized Conversion Expense	109	1.00%	1	0	0	0	0	46	47
3	178-00 Organization Expense	728	1.00%	7	0	0	0	0	333	340
4	179-01 Other Deferred Charges	0	1.00%	0	0	0	0	0	0	0
5	401-00 Franchise and Consents	99	1.00%	1	0	0	0	0	45	46
6	402-00 Utility Plant Acquisition Adjustment	63	1.00%	1	0	0	0	0	25	26
7	402-00 Other Intangible Plant - Lease	85	Lease	1	0	0	0	0	72	73
8		1,084		11	0	0	0	0	521	532
9										
10	**GAS PLANT HELD FOR FUTURE USE**									
11	492-00 Structures & Improvements									
12	- Frame Buildings	0	3.00%	0	0	0	0	0	0	0
13	- Masonry Buildings	0	1.50%	0	0	0	0	0	0	0
14	492-00 Manufacturing Equipment	0	3.00%	0	0	0	0	0	0	0
15	492-00 Gas Holder	0	2.00%	0	0	0	0	0	0	0
16	492-00 Compressor Equip/Commun. Equip.	0	5.00%	0	0	0	0	0	0	0
17	492-00 Gas Plant Held for Future Use	0	0.00%	0	0	0	0	0	0	0
18		0		0	0	0	0	0	0	0
19										
20	**MANUFACTURED GAS / LOCAL STORAGE PLANT**									
21	432 Manufact'd Gas - Struct. & Improvements									
22	- Frame Buildings	0	3.00%	0	0	0	0	0	0	0
23	- Masonry Buildings	413	1.50%	6	0	0	0	0	81	87
24	433 Manufacturing Equipment	269	3.00%	8	0	0	0	0	38	46
25	434 Gas Holders - Manufacturing	353	2.00%	7	0	0	0	0	137	144
26	436 Compressor Equipment	53	3.00%	1	0	0	0	0	13	14
27	437 Measuring & Regulating	295	3.00%	9	0	0	0	0	105	114
28	442-00 Structures and Improvements	4,347	4.00%	174	0	0	0	0	1,436	1,610
29	443-00 Gas Holders Storage	16,058	4.00%	642	0	0	0	0	6,458	7,100
30	449-00 Local Storage Equipment	16,453	4.00%	658	0	0	0	0	6,496	7,154
31		38,241		1,505	0	0	0	0	14,764	16,269

DEPRECIATION AND AMORTIZATION WORKSHEET (CONT'D)
FOR THE YEAR ENDING DECEMBER 31, 2005
($000)

Line No.	Account	Balance 12/31/2004	Annual Depreciation Rate %	Provision: 2005 (Cr.)	Provision: Adjust-ments	Provision: Retirements	Provision: Retirement Costs	Provision: Proceeds on Disposal	Accumulated 12/31/2004	Accumulated 12/31/2005
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**TRANSMISSION PLANT**									
2	461 Land Rights - Byron Creek	$0	5.00%	$0	$0	$0	$0	$0	$12	$12
3	462-00 Structures and Improvements									
4	- Compressor Stations	13,791	3.00%	414	0	0	0	0	3,010	3,424
5	463-00 Measuring & Regulating	3,048	3.00%	91	0	0	0	0	741	832
6	464-00 Other Structures - Frame Buildings	4,282	3.00%	128	0	0	0	0	470	598
7	465-00 Mains & Crossings	684,620	2.00%	13,692	0	(1,372)	(80)	0	119,706	131,946
8	465-00 Mains & Crossings - Byron Creek	885	2.00%	18	0	0	0	0	590	608
9	466-00 Compressor Equipment	105,329	3.00%	3,160	0	0	0	0	19,565	22,725
10	467-00 Measuring & Regulating	25,057	3.00%	752	0	0	0	0	4,839	5,591
11	467-10 Telemetering	5,797	10.00%	580	0	0	0	0	4,544	5,124
12	468-00 Communications Structures & Equip.	2,275	10.00%	228	0	0	0	0	530	758
13	469-00 Other Transmission Equipment	0	5.00%	0	0	0	0	0	0	0
14		845,084		19,063	0	(1,372)	(80)	0	154,007	171,618
15										
16	**DISTRIBUTION PLANT**									
17	471 Land Rights - Byron Creek	1	0.00%	0	0	0	0	0	1	1
18	472-00 Structures & Improvements									
19	-Leasehold Alterations	0	Term - Lease	0	0	0	0	0	0	0
20	-Frame Buildings	6,418	3.00%	193	0	0	0	0	1,640	1,833
21	-Masonry Buildings	0	1.50%	0	0	0	0	0	0	0
22	-Byron Creek	2	3.00%	0	0	0	0	0	2	2
23	473-00 Services	474,470	2.00%	9,489	0	(2,018)	(1,427)	0	73,663	79,707
24	474-00 House Regulator & Meter Installation	136,831	3.57%	4,885	0	(327)	(191)	2	32,675	37,044
25	475-00 Mains	639,807	2.00%	12,796	0	(1,663)	(191)	0	161,532	172,474
26	476-00 Compressed Natural Gas									
27										
28	-NGV Compressor Equipment	0	5.00%	0	0	0	0	0	0	0
29	-All Other	229	6.67%	15	0	0	0	0	157	172
30	477-00 Measuring & Regulating	58,277	3.00%	1,748	0	(304)	(10)	0	7,285	8,719
31	477-10 Telemetering	5,410	10.00%	541	0	0	0	0	4,434	4,975
32	477-00 Measuring & Regulating - Byron Creek	114	3.00%	3	0	0	0	0	114	117
33	478 Meters	169,636	3.57%	6,056	0	(550)	(23)	127	36,479	42,089
34	479 Other Distribution Equipment	500	4.00%	20	0	0	0	0	40	60
35		1,491,695		35,746	0	(4,862)	(1,842)	129	318,022	347,193

BC GAS UTILITY LTD.

DEPRECIATION AND AMORTIZATION WORKSHEET (CONT'D)
FOR THE YEAR ENDING DECEMBER 31, 2005
($000)

Line No.	Account	Balance 12/31/2004	Annual Depreciation Rate %	Provision: 2005 (Cr.)	Adjust-ments	Retirements	Retirement Costs	Proceeds on Disposal	Accumulated 12/31/2004	Accumulated 12/31/2005
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**GENERAL PLANT**									
2	482-00 Structures & Improvements									
3	-Leasehold Alterations	$14,572	Term - Lease	$1,974	$0	$0	$0	$0	$14,600	$16,574
4	-Masonry Buildings	21,736	1.50%	326	0	0	0	0	2,344	2,670
5	-Frame Buildings	4,552	3.00%	137	0	0	0	0	(3,366)	(3,229)
6	483-00 Office Furniture & Equipment									
7	-Furniture & Equipment	23,085	5.00%	1,154	0	(23)	0	0	9,474	10,605
8	-Computers - Hardware	22,058	20.00%	4,412	0	(2,221)	0	0	15,610	17,801
9										
10	-Computer Software - Non-Infrastructure	33,987	20.000%	6,797	0	(7,602)	0	0	22,084	21,279
11	-Computer Software - Infrastructure/Custom	107,321	12.50%	13,415	0	(722)	0	0	45,482	58,175
12										
13	484-00 Transportation Equipment	205	15.00%	31	0	0	0	0	2,432	2,463
14	485-00 Maintenance & Repair Equipment	8	5.00%	0	0	(8)	0	0	(366)	(374)
15	486-00 Tools & Work Equipment	27,336	5.00%	1,367	0	(178)	0	0	9,581	10,770
16	487-00 Equipment on Customers' Premises	1,644	5.00%	82	0	0	0	0	695	777
17	487-XX - VRA Compressor	0	10.00%	0	0	0	0	0	0	0
18	487-XX - VRA Compressor Installation Cost	0	33.33%	0	0	0	0	0	288	288
19	488-00 Communication - Structures & Equip.	11,112	5.00%	556	0	(779)	0	0	2,043	1,820
20	488-00 Communication - Radios	4,456	10.00%	446	0	0	0	0	3,333	3,779
21	489-00 Other General Equipment	0	5.00%	0	0	0	0	0	0	0
22		272,072		30,697	0	(11,533)	0	0	124,234	143,398
23										
24	**UNCLASSIFIED PLANT**									
25	498-00 O&M Expense Charged to Construction	252,915	2.20%	5,564	0	0	0	0	23,594	29,158
26										
27	TOTAL	$2,901,091		$92,586	$0	($17,767)	($1,922)	$129	$635,142	$708,168

DEPRECIATION AND AMORTIZATION WORKSHEET
FOR THE YEAR ENDING DECEMBER 31, 2006
($000)

Line No.	Account	Balance 12/31/2005	Annual Depreciation Rate %	Provision: 2006 (Cr.)	Provision: Adjust-ments	Provision: Retirements	Provision: Retirement Costs	Provision: Proceeds on Disposal	Accumulated 12/31/2005	Accumulated 12/31/2006
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	117-00 Utility Plant Acquisition Adj.	$0	1.00%	$0	$0	$0	$0	$0	$0	$0
2	175-00 Unamortized Conversion Expense	109	1.00%	1	0	0	0	0	47	48
3	178-00 Organization Expense	728	1.00%	7	0	0	0	0	340	347
4	179-01 Other Deferred Charges	0	1.00%	0	0	0	0	0	0	0
5	401-00 Franchise and Consents	99	1.00%	1	0	0	0	0	46	47
6	402-00 Utility Plant Acquisition Adjustment	63	1.00%	1	0	0	0	0	26	27
7	402-00 Other Intangible Plant - Lease	85	Lease	1	0	0	0	0	73	74
8		1,084		11	0	0	0	0	532	543
9										
10	**GAS PLANT HELD FOR FUTURE USE**									
11	492-00 Structures & Improvements									
12	- Frame Buildings	0	3.00%	0	0	0	0	0	0	0
13	- Masonry Buildings	0	1.50%	0	0	0	0	0	0	0
14	492-00 Manufacturing Equipment	0	3.00%	0	0	0	0	0	0	0
15	492-00 Gas Holder	0	2.00%	0	0	0	0	0	0	0
16	492-00 Compressor Equip/Commun. Equip.	0	5.00%	0	0	0	0	0	0	0
17	492-00 Gas Plant Held for Future Use	0	0.00%	0	0	0	0	0	0	0
18		0		0	0	0	0	0	0	0
19										
20	**MANUFACTURED GAS / LOCAL STORAGE PLANT**									
21	432 Manufact'd Gas - Struct. & Improvements									
22	- Frame Buildings	0	3.00%	0	0	0	0	0	0	0
23	- Masonry Buildings	413	1.50%	6	0	0	0	0	87	93
24	433 Manufacturing Equipment	269	3.00%	8	0	0	0	0	46	54
25	434 Gas Holders - Manufacturing	353	2.00%	7	0	0	0	0	144	151
26	436 Compressor Equipment	53	3.00%	1	0	0	0	0	14	15
27	437 Measuring & Regulating	295	3.00%	9	0	0	0	0	114	123
28	442-00 Structures and Improvements	4,347	4.00%	174	0	0	0	0	1,610	1,784
29	443-00 Gas Holders Storage	18,587	4.00%	743	0	0	0	0	7,100	7,843
30	449-00 Local Storage Equipment	16,453	4.00%	658	0	0	0	0	7,154	7,812
31		40,770		1,606	0	0	0	0	16,269	17,875

BC GAS UTILITY LTD.

DEPRECIATION AND AMORTIZATION WORKSHEET (CONT'D)
FOR THE YEAR ENDING DECEMBER 31, 2006
($000)

Line No.	Account	Balance 12/31/2005	Annual Depreciation Rate %	Provision 2006 (Cr.)	Adjust-ments	Retirements	Retirement Costs	Proceeds on Disposal	Accumulated 12/31/2005	Accumulated 12/31/2006
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**TRANSMISSION PLANT**									
2	461 Land Rights - Byron Creek	$0	5.00%	$0	$0	$0	$0	$0	$12	$12
3	462-00 Structures and Improvements									
4	- Compressor Stations	14,080	3.00%	422	0	0	0	0	3,424	3,846
5	463-00 Measuring & Regulating	3,048	3.00%	91	0	0	0	0	832	923
6	464-00 Other Structures - Frame Buildings	4,282	3.00%	128	0	0	0	0	598	726
7	465-00 Mains & Crossings	710,688	2.00%	14,214	0	(2,658)	(82)	0	131,946	143,420
8	465-00 Mains & Crossings - Byron Creek	885	2.00%	18	0	0	0	0	608	626
9	466-00 Compressor Equipment	105,368	3.00%	3,161	0	0	0	0	22,725	25,886
10	467-00 Measuring & Regulating	25,739	3.00%	772	0	0	0	0	5,591	6,363
11	467-10 Telemetering	5,797	10.00%	580	0	0	0	0	5,124	5,704
12	468-00 Communications Structures & Equip.	2,777	10.00%	278	0	0	0	0	758	1,036
13	469-00 Other Transmission Equipment	0	5.00%	0	0	0	0	0	0	0
14		872,664		19,664	0	(2,658)	(82)	0	171,618	188,542
15										
16	**DISTRIBUTION PLANT**									
17	471 Land Rights - Byron Creek	1	0.00%	0	0	0	0	0	1	1
18	472-00 Structures & Improvements									
19	-Leasehold Alterations	0	Term - Lease	0	0	0	0	0	0	0
20	-Frame Buildings	6,663	3.00%	200	0	0	0	0	1,833	2,033
21	-Masonry Buildings	0	1.50%	0	0	0	0	0	0	0
22	-Byron Creek	2	3.00%	0	0	0	0	0	2	2
23	473-00 Services	485,907	2.00%	9,718	0	(2,076)	(1,467)	0	79,707	85,882
24	474-00 House Regulator & Meter Installation	143,040	3.57%	5,107	0	(332)	(194)	2	37,044	41,627
25	475-00 Mains	654,778	2.00%	13,096	0	(2,211)	(197)	0	172,474	183,162
26	476-00 Compressed Natural Gas									
27										
28	-NGV Compressor Equipment	0	5.00%	0	0	0	0	0	0	0
29	-All Other	229	6.67%	15	0	0	0	0	172	187
30	477-00 Measuring & Regulating	63,958	3.00%	1,919	0	(304)	(10)	0	8,719	10,324
31	477-10 Telemetering	5,511	10.00%	551	0	0	0	0	4,975	5,526
32	477-00 Measuring & Regulating - Byron Creek	114	3.00%	3	0	0	0	0	117	120
33	478 Meters	180,087	3.57%	6,429	0	(567)	(24)	129	42,089	48,056
34	479 Other Distribution Equipment	500	4.00%	20	0	0	0	0	60	80
35		1,540,790		37,058	0	(5,490)	(1,892)	131	347,193	377,000

BC GAS UTILITY LTD.

DEPRECIATION AND AMORTIZATION WORKSHEET (CONT'D)
FOR THE YEAR ENDING DECEMBER 31, 2006
($000)

Line No.	Account	Balance 12/31/2005	Annual Depreciation Rate %	Provision 2006 (Cr.)	Adjust-ments	Retirements	Retirement Costs	Proceeds on Disposal	Accumulated 12/31/2005	Accumulated 12/31/2006
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**GENERAL PLANT**									
2	482-00 Structures & Improvements									
3	-Leasehold Alterations	$15,207	Term - Lease	$2,006	$0	$0	$0	$0	$16,574	$18,580
4	-Masonry Buildings	21,736	1.50%	326	0	0	0	0	2,670	2,996
5	-Frame Buildings	4,552	3.00%	137	0	0	0	0	(3,229)	(3,092)
6	483-00 Office Furniture & Equipment									
7	-Furniture & Equipment	23,559	5.00%	1,178	0	(47)	0	0	10,605	11,736
8	-Computers - Hardware	23,338	20.00%	4,668	0	(5,006)	0	0	17,801	17,463
9	-Computers Micro. Comp. System	0	12.50%	0	0	0	0	0	0	0
10	-Computer Software - Non-Infrastructure	29,735	20.000%	5,947	0	(14,091)	0	0	21,279	13,135
11	-Computer Software - Infrastructure/Custom	118,609	12.50%	14,826	0	(27,351)	0	0	58,175	45,650
12										
13	484-00 Transportation Equipment	253	15.00%	38	0	(13)	0	0	2,463	2,488
14	485-00 Maintenance & Repair Equipment	0	5.00%	0	0	0	0	0	(374)	(374)
15	486-00 Tools & Work Equipment	29,335	5.00%	1,467	0	(161)	0	0	10,770	12,076
16	487-00 Equipment on Customers' Premises	1,644	5.00%	82	0	0	0	0	777	859
17	487-XX - VRA Compressor	0	10.00%	0	0	0	0	0	0	0
18	487-XX - VRA Compressor Installation Cost	0	33.33%	0	0	0	0	0	288	288
19	488-00 Communication - Structures & Equip.	11,651	5.00%	583	0	(87)	0	0	1,820	2,316
20	488-00 Communication - Radios	4,207	10.00%	421	0	0	0	0	3,779	4,200
21	489-00 Other General Equipment	0	5.00%	0	0	0	0	0	0	0
22		283,826		31,679	0	(46,756)	0	0	143,398	128,321
23										
24	**UNCLASSIFIED PLANT**									
25	498-00 O&M Expense Charged to Construction	270,832	2.20%	5,958	0	0	0	0	29,158	35,116
26										
27	TOTAL	$3,009,966		$95,976	$0	($54,904)	($1,974)	$131	$708,168	$747,397

BC GAS UTILITY LTD.

DEPRECIATION AND AMORTIZATION WORKSHEET
FOR THE YEAR ENDING DECEMBER 31, 2007
($000)

Line No.	Account	Balance 12/31/2006	Annual Depreciation Rate %	Provision 2007 (Cr.)	Adjust-ments	Retirements	Retirement Costs	Proceeds on Disposal	Accumulated 12/31/2006	Accumulated 12/31/2007
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	117-00 Utility Plant Acquisition Adj.	$0	1.00%	$0	$0	$0	$0	$0	$0	$0
2	175-00 Unamortized Conversion Expense	109	1.00%	1	0	0	0	0	48	49
3	178-00 Organization Expense	728	1.00%	7	0	0	0	0	347	354
4	179-01 Other Deferred Charges	0	1.00%	0	0	0	0	0	0	0
5	401-00 Franchise and Consents	99	1.00%	1	0	0	0	0	47	48
6	402-00 Utility Plant Acquisition Adjustment	63	1.00%	1	0	0	0	0	27	28
7	402-00 Other Intangible Plant - Lease	85	Lease	1	0	0	0	0	74	75
8		1,084		11	0	0	0	0	543	554
9										
10	**GAS PLANT HELD FOR FUTURE USE**									
11	492-00 Structures & Improvements									
12	- Frame Buildings	0	3.00%	0	0	0	0	0	0	0
13	- Masonry Buildings	0	1.50%	0	0	0	0	0	0	0
14	492-00 Manufacturing Equipment	0	3.00%	0	0	0	0	0	0	0
15	492-00 Gas Holder	0	2.00%	0	0	0	0	0	0	0
16	492-00 Compressor Equip/Commun. Equip.	0	5.00%	0	0	0	0	0	0	0
17	492-00 Gas Plant Held for Future Use	0	0.00%	0	0	0	0	0	0	0
18		0		0	0	0	0	0	0	0
19										
20	**MANUFACTURED GAS / LOCAL STORAGE PLANT**									
21	432 Manufact'd Gas - Struct. & Improvements									
22	- Frame Buildings	0	3.00%	0	0	0	0	0	0	0
23	- Masonry Buildings	413	1.50%	6	0	0	0	0	93	99
24	433 Manufacturing Equipment	269	3.00%	8	0	0	0	0	54	62
25	434 Gas Holders - Manufacturing	353	2.00%	7	0	0	0	0	151	158
26	436 Compressor Equipment	53	3.00%	1	0	0	0	0	15	16
27	437 Measuring & Regulating	295	3.00%	9	0	0	0	0	123	132
28	442-00 Structures and Improvements	4,347	4.00%	174	0	0	0	0	1,784	1,958
29	443-00 Gas Holders Storage	18,981	4.00%	759	0	0	0	0	7,843	8,602
30	449-00 Local Storage Equipment	16,453	4.00%	658	0	0	0	0	7,812	8,470
31		41,164		1,622	0	0	0	0	17,875	19,497

DEPRECIATION AND AMORTIZATION WORKSHEET (CONT'D)
FOR THE YEAR ENDING DECEMBER 31, 2007
($000)

Line No.	Account	Balance 12/31/2006	Annual Depreciation Rate %	Provision 2007 (Cr.)	Adjust-ments	Retirements	Retirement Costs	Proceeds on Disposal	Accumulated 12/31/2006	Accumulated 12/31/2007
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**TRANSMISSION PLANT**									
2	461 Land Rights - Byron Creek	$0	5.00%	$0	$0	$0	$0	$0	$12	$12
3	462-00 Structures and Improvements									
4	- Compressor Stations	18,347	3.00%	550	0	0	0	0	3,846	4,396
5	463-00 Measuring & Regulating	3,048	3.00%	91	0	0	0	0	923	1,014
6	464-00 Other Structures - Frame Buildings	4,282	3.00%	128	0	0	0	0	726	854
7	465-00 Mains & Crossings	761,197	2.00%	15,224	0	(178)	(83)	0	143,420	158,383
8	465-00 Mains & Crossings - Byron Creek	885	2.00%	18	0	0	0	0	626	644
9	466-00 Compressor Equipment	115,336	3.00%	3,460	0	0	0	0	25,886	29,346
10	467-00 Measuring & Regulating	32,382	3.00%	971	0	0	0	0	6,363	7,334
11	467-10 Telemetering	5,797	10.00%	580	0	0	0	0	5,704	6,284
12	468-00 Communications Structures & Equip.	3,289	10.00%	329	0	0	0	0	1,036	1,365
13	469-00 Other Transmission Equipment	0	5.00%	0	0	0	0	0	0	0
14		944,563		21,351	0	(178)	(83)	0	188,542	209,632
15										
16	**DISTRIBUTION PLANT**									
17	471 Land Rights - Byron Creek	1	0.00%	0	0	0	0	0	1	1
18	472-00 Structures & Improvements									
19	-Leasehold Alterations	0	Term - Lease	0	0	0	0	0	0	0
20	-Frame Buildings	6,913	3.00%	207	0	0	0	0	2,033	2,240
21	-Masonry Buildings	0	1.50%	0	0	0	0	0	0	0
22	-Byron Creek	2	3.00%	0	0	0	0	0	2	2
23	473-00 Services	497,668	2.00%	9,953	0	(2,149)	(1,527)	0	85,882	92,159
24	474-00 House Regulator & Meter Installation	149,354	3.57%	5,332	0	(337)	(197)	2	41,627	46,427
25	475-00 Mains	674,673	2.00%	13,493	0	(1,531)	(205)	0	183,162	194,919
26	476-00 Compressed Natural Gas									
27										
28	-NGV Compressor Equipment	0	5.00%	0	0	0	0	0	0	0
29	-All Other	229	6.67%	15	0	0	0	0	187	202
30	477-00 Measuring & Regulating	69,633	3.00%	2,089	0	(301)	(10)	0	10,324	12,102
31	477-10 Telemetering	5,614	10.00%	561	0	0	0	0	5,526	6,087
32	477-00 Measuring & Regulating - Byron Creek	114	3.00%	3	0	0	0	0	120	123
33	478 Meters	190,869	3.57%	6,814	0	(586)	(24)	132	48,056	54,392
34	479 Other Distribution Equipment	500	4.00%	20	0	0	0	0	80	100
35		1,595,570		38,487	0	(4,904)	(1,963)	134	377,000	408,754

BC GAS UTILITY LTD.

DEPRECIATION AND AMORTIZATION WORKSHEET (CONT'D)
FOR THE YEAR ENDING DECEMBER 31, 2007
($000)

Line No.	Account	Balance 12/31/2006	Annual Depreciation Rate %	Provision 2007 (Cr.)	Adjust-ments	Retirements	Retirement Costs	Proceeds on Disposal	Accumulated 12/31/2006	Accumulated 12/31/2007
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**GENERAL PLANT**									
2	482-00 Structures & Improvements									
3	-Leasehold Alterations	$15,856	Term - Lease	$2,038	$0	$0	$0	$0	$18,580	$20,618
4	-Masonry Buildings	21,735	1.50%	326	0	0	0	0	2,996	3,322
5	-Frame Buildings	4,552	3.00%	137	0	0	0	0	(3,092)	(2,955)
6	483-00 Office Furniture & Equipment									
7	-Furniture & Equipment	24,019	5.00%	1,201	0	(39)	0	0	11,736	12,898
8	-Computers - Hardware	23,964	20.00%	4,793	0	(5,536)	0	0	17,463	16,720
9										
10	-Computer Software - Non-Infrastructure	16,644	20.000%	3,329	0	(14,737)	0	0	13,135	1,727
11	-Computer Software - Infrastructure/Custom	104,391	12.50%	13,049	0	0	0	0	45,650	58,699
12										
13	484-00 Transportation Equipment	289	15.00%	43	0	(24)	0	0	2,488	2,507
14	485-00 Maintenance & Repair Equipment	0	5.00%	0	0	0	0	0	(374)	(374)
15	486-00 Tools & Work Equipment	31,395	5.00%	1,570	0	(164)	0	0	12,076	13,482
16	487-00 Equipment on Customers' Premises	1,644	5.00%	82	0	0	0	0	859	941
17	487-XX - VRA Compressor	0	10.00%	0	0	0	0	0	0	0
18	487-XX - VRA Compressor Installation Cost	0	33.33%	0	0	0	0	0	288	288
19	488-00 Communication - Structures & Equip.	12,201	5.00%	610	0	(556)	0	0	2,316	2,370
20	488-00 Communication - Radios	4,661	10.00%	466	0	0	0	0	4,200	4,666
21	489-00 Other General Equipment	0	5.00%	0	0	0	0	0	0	0
22		261,351		27,644	0	(21,056)	0	0	128,321	134,909
23										
24	**UNCLASSIFIED PLANT**									
25	498-00 O&M Expense Charged to Construction	289,269	2.20%	6,364	0	0	0	0	35,116	41,480
26										
27	TOTAL	$3,133,001		$95,479	$0	($26,138)	($2,046)	$134	$747,397	$814,826

($000)

Line No.	Particulars	Plant 12/31/2001	Annual Depreciation Rate %	Projected 2002 Depreciation Provision	Projected 2002 Adjust-ments	Projected 2002 Retirements	Projected 2002 Retirement Costs	Projected 2002 Proceeds on Disposal	Accumulated Recorded 12/31/2001	Accumulated Projected 12/31/2002
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	175-Unamortized Conversion Expense	109	1.00%	$1	$0	$0	$0	$0	$43	$44
2	178-Organization Expense	728	1.00%	7	0	0	0	0	312	319
3	179-Other Deferred Charges	0	1.00%	0	0	0	0	0	0	0
4	401-Franchise and Consents	99	1.00%	1	0	0	0	0	42	43
5	402-Utility Plant Acquisition Adj.	63	1.00%	1	0	0	0	0	22	23
6	402-Other Intangible Plant - Lease	85	Lease Term	1	0	0	0	0	69	70
7		1,084		11	0	0	0	0	488	499
8										
9	**GAS PLANT HELD FOR FUTURE USE**									
10	492-Structures & Improvements									
11	- Frame Buildings	0	3.00%	0	0	0	0	0	0	0
12	- Masonry Buildings	0	1.50%	0	0	0	0	0	0	0
13	492-Manufacturing Equipment	0	3.00%	0	0	0	0	0	0	0
14	492-Gas Holder / Services	0	2.00%	0	0	0	0	0	0	0
15	492-Compressor Equip/Commun. Equip.	0	5.00%	0	0	0	0	0	0	0
16		0		0	0	0	0	0	0	0
17										
18	**MANUFACTURED GAS / LOCAL STORAGE PLANT**									
19	432 Manufactured Gas - Structures & Improvements									
20	- Frame Buildings	0	3.00%	0	0	0	0	0	0	0
21	- Masonry Buildings	385	1.50%	6	0	0	(1)	9	55	69
22	433 Manufacturing Equipment	136	3.00%	4	0	0	0	0	18	22
23	434 Gas Holders - Manufacturing	353	2.00%	7	0	0	0	0	116	123
24	436 Compressor Equipment	53	3.00%	1	0	0	0	0	10	11
25	437 Measuring & Regulating	295	3.00%	9	0	0	0	0	78	87
26	442-Structures and Improvements	2,899	4.00%	116	0	0	0	0	975	1,091
27	443-Gas Holders Storage	10,261	4.00%	410	0	0	0	0	4,992	5,402
28	449-Local Storage Equipment	15,479	4.00%	619	0	0	0	0	4,561	5,180
29		29,861		1,172	0	0	(1)	9	10,805	11,985

($000)

Line No.	Particulars	Plant 12/31/2001	Annual Depreciation Rate %	Projected 2002 Depreciation Provision	Adjust-ments	Retirements	Retirement Costs	Proceeds on Disposal	Accumulated Recorded 12/31/2001	Projected 12/31/2002
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**TRANSMISSION PLANT**									
2	461-Land Rights - Byron Creek	16	5.00%	0	0	0	0	0	12	12
3	462-Compressor Structures	12,518	3.00%	376	0	0	0	0	1,832	2,208
4	463-Measuring & Regulating Structures	3,044	3.00%	91	0	0	(4)	0	472	559
5	464-Other	4,282	3.00%	128	0	0	0	0	86	214
6	465-Mains & Crossings	637,623	2.00%	12,752	0	(1,112)	(76)	0	83,048	94,612
7	465-Mains & Crossings - Byron Creek	655	5.00%	33	0	0	0	0	521	554
8	466-Compressor Equipment	95,614	3.00%	2,868	0	0	0	0	10,381	13,249
9	467-Measuring & Regulating	19,733	3.00%	592	0	0	0	0	2,933	3,525
10	467-Telemetering	5,628	10.00%	563	0	0	0	0	2,821	3,384
11	468-Communications Structures & Equip.	549	10.00%	55	0	0	0	0	167	222
12	469-Other Transmission Equipment	0	5.00%	0	0	0	0	0	0	0
13		779,662		17,458	0	(1,112)	(80)	0	102,273	118,539
14										
15	**DISTRIBUTION PLANT**									
16	471-Land Rights - Byron Creek	1	5.00%	0	0	0	0	0	1	1
17	472-Structures & Improvements									
18	-Leasehold Alterations	0	Term - Lease	0	0	0	0	0	0	0
19	-Frame Buildings	5,936	3.00%	178	0	0	0	0	1,097	1,275
20	-Masonry Buildings	0	1.50%	0	0	0	0	0	0	0
21	-Byron Creek	2	5.00%	0	0	0	0	0	2	2
22	473-Services	443,433	2.00%	8,869	0	(1,501)	(1,317)	0	56,116	62,167
23	474-Regulator & Meter Installation	121,081	3.00%	3,632	0	(190)	(164)	2	21,997	25,277
24	475-Mains	591,424	2.00%	11,828	0	(1,457)	(177)	0	131,078	141,272
25	476-Compressed Natural Gas									
26										
27										
28	-All Other	229	6.67%	15	0	0	0	0	112	127
29	477-Measuring & Regulating	42,771	3.00%	1,283	0	(181)	0	0	3,883	4,985
30	477-Telemetering	5,019	10.00%	502	0	(10)	(9)	0	2,899	3,382
31	477-Measuring & Regulating - Byron Creek	114	5.00%	6	0	0	0	0	102	108
32	478-Meters	138,529	3.00%	4,156	0	(579)	(22)	120	23,482	27,157
33	479-Other Distribution Equipment	0	4.00%	0	0	0	0	0	0	0
34		1,348,539		30,469	0	(3,918)	(1,689)	122	240,769	265,753

BC GAS UTILITY LTD.
CONTINUITY OF ACCUMULATED DEPRECIATION (CONT'D)
FOR THE YEAR ENDING DECEMBER 31, 2002
($000)

Line No.	Particulars	Plant 12/31/2001	Annual Depreciation Rate %	Projected 2002 Depreciation Provision	Projected 2002 Adjust-ments	Projected 2002 Retirements	Projected 2002 Retirement Costs	Projected 2002 Proceeds on Disposal	Accumulated Recorded 12/31/2001	Accumulated Projected 12/31/2002
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**GENERAL PLANT**									
2	482- Structures & Improvements									
3	-Leasehold Alterations	12,796	Term - Lease	1,886	0	0	0	0	8,858	10,744
4										
5	-Frame Buildings	4,552	3.00%	137	0	0	0	0	(3,777)	(3,640)
6	-All Other - Masonry Buildings	21,083	1.50%	316	0	0	0	0	1,376	1,692
7	483-Office Furniture & Equipment									
8	-Furniture & Equipment	21,692	5.00%	1,085	0	(118)	0	2	6,297	7,266
9	-Computers - Hardware	24,572	20.00%	4,914	0	(7,056)	0	0	19,527	17,385
10	-Computer Software - Non-Infrastructure	35,687	12.50%	4,461	0	0	0	0	11,946	16,407
11										
12	-Computer Software - Infrastructure/Custom	64,441	12.50%	8,055	0	0	0	0	17,082	25,137
13										
14	484-Transportation Equipment	615	15.00%	92	0	(682)	0	75	3,115	2,600
15	485-Maintenance & Repair Equipment	18	5.00%	1	0	(6)	0	0	(359)	(364)
16	486-Tools & Work Equipment	22,368	5.00%	1,118	0	(646)	0	0	7,074	7,546
17	487-Equipment on Customers' Premises	1,644	5.00%	82	0	0	0	0	449	531
18	- VRA Compressor	0	10.00%	0	0	0	0	0	0	0
19	- VRA Compressor Installation Cost	583	33.33%	194	0	(583)	0	0	677	288
20	488-Communication - Structures & Equip.	9,471	5.00%	474	0	(4)	0	0	1,782	2,252
21	488-Communication - Radios	8,405	10.00%	841	0	(3,960)	0	0	5,494	2,375
22	489-Other General Equipment	0	5.00%	0	0	0	0	0	0	0
23		227,927		23,656	0	(13,055)	0	77	79,541	90,219
24		228,390								
25	**UNCLASSIFIED PLANT**									
26	498-O&M Overhead Expense Charged to Construction	174,803	2.20%	3,846	0	0	0	0	10,380	14,226
27										
28	**TOTALS**	$2,561,876		$76,612	$0	($18,085)	($1,770)	$208	$444,256	$501,221

BC GAS UTILITY LTD.
WORKING CAPITAL ALLOWANCE
FOR THE YEARS ENDING DECEMBER 31, 2003 TO 2007

The major components of the working capital allowance have been divided into the following three categories.

- Cash Required for Operating Expenses
- Gas in Storage and Transmission Linepack
- All Other Working Capital items

Cash Required for Operating Expenses (Tab 5, Page 2)

Cash Required for Operating Expenses will continue to be determined using the lead/lag methodology established in 1992 with BC Gas' 1992 Revenue Requirement Application.

For the 2003-2007 period, adjustments were made to the revenue lead days for Lower Mainland Residential, Commercial, General Firm and NGV customers to reflect the repatriation in early July of these customers from B.C. Hydro to BC Gas and its billing service provided by CustomerWorks. Under this new billing system, Residential and Commercial customers in the Lower Mainland will be billed on a monthly basis as opposed to the current B.C. Hydro practice of billing bi-monthly. This change has the net effect of lowering the revenue lead days from 47.4 days to 34.6 days. The costs of monthly billing are discussed in Section D, Page D – 65.

Adjustments were also made to shorten the Schedules 1, 2, and 3 revenue lead days for the Inland and Columbia Service Areas as a result of efficiencies associated with the Energy billing system. The revenue lead days for the Inland and Columbia service areas have been adjusted to 34.6 days.

The result of the revenue lead-day shortening is a reduction in 2003 rate base in excess of $32 million.

BC GAS UTILITY LTD.
WORKING CAPITAL ALLOWANCE
FOR THE YEARS ENDING DECEMBER 31, 2003 TO 2007

Gas in Storage and Transmission Linepack (Tab 5, Page 2, Lines 19 and 20)

Gas in Storage and Transmission Linepack are subject to significant swings in their inventory values, particularly due to volatility in gas pricing from year to year. The amounts identified under Tab 5, Page 2, Lines 19 and 20 represent current best estimates, based on the gas storage contracts in effect and late March 2002 forward prices, for Gas in Storage and Transmission Linepack.

All Other Working Capital (Tab 5, Page 2, Lines 6, 10, 13, and 18)

Other working capital items include minimum cash balances, customer deposits, reserve for bad debts, employee withholdings, and inventories. The forecast 2003-2007 costs for these items have been reasonably estimated.

BC GAS UTILITY LTD.

WORKING CAPITAL ALLOWANCE
FOR THE YEARS ENDING DECEMBER 31, 2003 TO 2005
($000)

		2003		2004		2005		
Line No.	Particulars	Present Revenue	Revised Revenue	2003 Rates	Revised Revenue	2004 Rates	Revised Revenue	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**Cash Working Capital**							
2	Cash Required for							
3	Operating Expenses	($7,981)	($7,614)	($7,804)	($7,829)	($7,330)	($7,052)	- Tab 5, Page 3
4								
5	Minimum Cash Balances/							
6	Customer Deposits	(2,478)	(2,478)	(2,550)	(2,550)	(2,629)	(2,629)	
7								
8	Less - Funds Available:							
9								
10	Reserve for Bad Debts	(374)	(374)	(385)	(385)	(397)	(397)	
11								
12	Withholdings From							
13	Employees	(2,618)	(2,618)	(2,694)	(2,694)	(2,778)	(2,778)	
14								
15	Subtotal	(13,451)	(13,084)	(13,433)	(13,458)	(13,134)	(12,856)	- Tab 2, Pages 1 & 1.1
16								
17	**Other Working Capital Items**							
18	Inventories	4,764	4,764	4,817	4,817	4,872	4,872	
19	Transmission Line Pack Gas	1,825	1,825	1,831	1,831	1,861	1,861	
20	Gas in Storage	91,896	91,896	95,846	95,846	98,290	98,290	
21								
22								
23	Subtotal	98,485	98,485	102,494	102,494	105,023	105,023	- Tab 2, Pages 1 & 1.1
24								
25	Total	$85,034	$85,401	$89,061	$89,036	$91,889	$92,167	

BC GAS UTILITY LTD.

WORKING CAPITAL ALLOWANCE
FOR THE YEARS ENDING DECEMBER 31, 2006 AND 2007
($000)

Line No.	Particulars	2006 2005 Rates	2006 Revised Revenue	2007 2006 Rates	2007 Revised Revenue	Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**Cash Working Capital**					
2	Cash Required for					
3	Operating Expenses	($7,161)	($6,864)	($6,947)	($6,633)	- Tab 5, Page 3.1
4						
5	Minimum Cash Balances/					
6	Customer Deposits	(2,712)	(2,712)	(2,796)	(2,796)	
7						
8	Less - Funds Available:					
9						
10	Reserve for Bad Debts	(409)	(409)	(422)	(422)	
11						
12	Withholdings From					
13	Employees	(2,865)	(2,865)	(2,954)	(2,954)	
14						
15	Subtotal	(13,147)	(12,850)	(13,119)	(12,805)	- Tab 2, Page 1.2
16						
17	**Other Working Capital Items**					
18	Inventories	4,932	4,932	4,983	4,983	
19	Transmission Line Pack Gas	1,871	1,871	1,877	1,877	
20	Gas in Storage	101,158	101,158	103,616	103,616	
21						
22						
23	Subtotal	107,961	107,961	110,476	110,476	- Tab 2, Page 1.2
24						
25	Total	$94,814	$95,111	$97,357	$97,671	

BC GAS UTILITY LTD.

CASH WORKING CAPITAL
FOR THE YEARS ENDING DECEMBER 31, 2003 TO 2005
($000)

		2003			2004			2005			
Line No.	Particulars	Days	Expenses	Cash Working Capital	Days	Expenses	Cash Working Capital	Days	Expenses	Cash Working Capital	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	WORKING CAPITAL										
2											
3	Revenue Lead Days	35.0			35.0			35.0			- Tab 5, Page 4
4	Expense Lag Days	37.6			37.5			37.3			- Tab 5, Page 5
5											
6	Net Lead/(Lag) Days	(2.6)	$1,120,396	($7,981)	(2.5)	$1,139,334	($7,804)	(2.3)	$1,166,486	($7,330)	- Tab 5, Page 2
7											
8											
9											
10	WORKING CAPITAL CHANGE			$367			($25)			$278	
11											
12											
13	WORKING CAPITAL, REVISED RATES										
14											
15	Revenue Lead Days	35.0			35.0			35.0			- Tab 5, Page 4
16	Expense Lag Days	37.5			37.5			37.2			- Tab 5, Page 5
17											
18	Net Lead/(Lag) Days	(2.5)	$1,126,085	($7,614)	(2.5)	$1,143,010	($7,829)	(2.2)	$1,173,138	($7,052)	- Tab 5, Page 2
19											

BC GAS UTILITY LTD.

CASH WORKING CAPITAL
FOR THE YEARS ENDING DECEMBER 31, 2006 AND 2007
($000)

		2006			2007			
Line No.	Particulars	Days	Expenses	Cash Working Capital	Days	Expenses	Cash Working Capital	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	WORKING CAPITAL							
2								
3	Revenue Lead Days	35.0			35.0			- Tab 5, Page 4.1
4	Expense Lag Days	37.2			37.1			- Tab 5, Page 5.1
5								
6	Net Lead/(Lag) Days	(2.2)	$1,187,997	($7,161)	(2.1)	$1,207,369	($6,947)	- Tab 5, Page 2.1
7								
8								
9								
10	WORKING CAPITAL CHANGE			$297			$314	
11								
12								
13	WORKING CAPITAL, REVISED RATES							
14								
15	Revenue Lead Days	35.0			35.0			- Tab 5, Page 4.1
16	Expense Lag Days	37.1			37.0			- Tab 5, Page 5.1
17								
18	Net Lead/(Lag) Days	(2.1)	$1,193,007	($6,864)	(2.0)	$1,210,563	($6,633)	- Tab 5, Page 2.1
19								
20								
21								

BC GAS UTILITY LTD.

CASH WORKING CAPITAL
LEAD TIME FROM DATE OF PAYMENT TO RECEIPT OF CASH
FOR THE YEARS ENDING DECEMBER 31, 2003 TO 2005
($000)

Line No.	Particulars	2003 Present Revenue	2003 Lead Days Service to Collection	2003 Dollar Days	2004 Revenue At 2003 Rates	2004 Lead Days Service to Collection	2004 Dollar Days	2005 Revenue At 2004 Rates	2005 Lead Days Service to Collection	2005 Dollar Days	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	REVENUE										
2											
3	Gas Sales and Transportation Service Revenue										
4	Schedules 1, 2 and 3	$1,100,976	34.6	$38,093,769	$1,126,597	34.6	$38,980,256	$1,146,293	34.6	$39,661,738	- Tab 7, Page 1
5	Schedules 4, 5, 7, 23, 25 and 27	79,751	39.1	3,119,095	80,471	39.1	3,148,795	81,620	39.2	3,195,696	- Tab 7, Page 1
6	NGV Fuel - Stations	4,377	38.4	168,288	4,536	38.6	175,181	5,033	38.5	194,012	- Tab 7, Page 1
7											
8	Sched. 22, Burrard, Centra Gas and										
9	SCP Third Party Revenue	40,997	39.2	1,606,368	40,944	39.2	1,605,496	41,573	39.2	1,630,017	- Tab7, Page 1 /
10											Tab 12, Page 2
11	Total Gas Sales	1,226,101	35.1	42,987,520	1,252,548	35.1	43,909,728	1,274,519	35.1	44,681,463	
12	Other Revenues										
13	Late Payment Charges	4,717	26.7	125,736	4,838	26.7	128,953	4,884	26.7	130,179	- Tab 12, Page 2
14	Returned Cheque Charges	198	31.8	6,304	198	31.8	6,304	198	31.8	6,304	- Tab 12, Page 2
15	Connection Charges	4,429	36.9	163,301	4,331	36.8	159,419	4,375	36.8	160,998	- Tab 12, Page 2
16	Other Utility Income	950	34.9	33,155	967	35.1	33,748	986	35.1	34,411	
17											
18											
19	Total	$1,236,395	35.0	$43,316,016	$1,262,882	35.0	$44,238,152	$1,284,962	35.0	$45,013,355	
20											
21											
22	REVENUE, REVISED RATES										
23											
24	Gas Sales and Transportation Service Revenue										
25	Schedules 1, 2 and 3	$1,115,540	34.6	$38,597,684	$1,135,700	34.6	$39,295,220	$1,162,789	34.6	$40,232,499	
26	Schedules 4, 5, 7, 23, 25 and 27	80,380	39.1	3,142,858	81,432	39.1	3,183,991	83,342	39.2	3,267,006	
27	NGV Fuel - Stations	4,391	38.4	168,614	4,569	38.6	176,363	5,098	38.5	196,273	
28											
29	Sched. 22, Burrard, Centra Gas and										
30	SCP Third Party Revenue	41,155	39.2	1,613,276	41,327	39.2	1,620,018	42,266	39.2	1,656,827	
31											
32	Total Gas Sales	1,241,466	35.1	43,522,432	1,263,028	35.1	44,275,592	1,293,495	35.1	45,352,605	
33	Other Revenues										
34	Late Payment Charges	4,717	26.7	125,944	4,838	26.7	129,175	4,884	26.7	130,403	- Tab 12, Page 2
35	Returned Cheque Charges	198	31.8	6,296	198	31.8	6,296	198	31.8	6,296	- Tab 12, Page 2
36	Connection Charges	4,429	36.9	163,430	4,331	36.8	159,381	4,375	36.8	161,000	- Tab 12, Page 2
37	Other Utility Income	950	35.1	33,345	967	35.1	33,942	986	35.1	34,609	
38											
39											
40	Total	$1,251,760	35.0	$43,851,447	$1,273,362	35.0	$44,604,386	$1,303,938	35.0	$45,684,913	

BC GAS UTILITY LTD.

CASH WORKING CAPITAL
LEAD TIME FROM DATE OF PAYMENT TO RECEIPT OF CASH
FOR THE YEARS ENDING DECEMBER 31, 2006 AND 2007
($000)

Line No.	Particulars	2006 Revenue At 2005 Rates	2006 Lead Days Service to Collection	2006 Dollar Days	2007 Revenue At 2006 Rates	2007 Lead Days Service to Collection	2007 Dollar Days	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	REVENUE							
2								
3	Gas Sales and Transportation Service Revenue							
4	Residential and Commercial	$1,173,542	34.6	$40,604,554	$1,196,743	34.6	$41,407,308	- Tab 7, Page 1
5	Schedules 4, 5, 7, 23, 25 and 27	83,566	39.2	3,275,533	84,911	39.2	3,330,684	- Tab 7, Page 1
6	NGV Fuel - Stations	5,651	38.6	218,284	6,368	38.6	245,807	- Tab 7, Page 1
7								
8	Sched. 22, Burrard, Centra Gas, SCP Third Party Rev.	42,402	39.2	1,662,961	43,067	39.2	1,689,593	- Tab7, Page 1 /
9								Tab 12, Page 2
10								
11	Total Gas Sales	1,305,161	35.1	45,761,332	1,331,089	35.1	46,673,392	
12	Other Revenues							
13	Late Payment Charges	4,929	26.7	131,379	4,975	26.7	132,606	- Tab 12, Page 2
14	Returned Cheque Charges	198	31.8	6,304	198	31.8	6,304	- Tab 12, Page 2
15	Connection Charges	4,439	36.8	163,186	4,484	36.7	164,556	- Tab 12, Page 2
16	Other Utility Income	1,006	35.1	35,109	1,026	34.9	35,807	
17								
18								
19	Total	$1,315,733	35.0	$46,097,310	$1,341,772	35.0	$47,012,665	
20								
21								
22	REVENUE, REVISED RATES							
23								
24	Gas Sales and Transportation Service Revenue							
25	Residential and Commercial	$1,185,751	34.6	$41,026,985	$1,204,680	34.6	$41,681,928	
26	Schedules 4, 5, 7, 23, 25 and 27	84,830	39.2	3,325,336	85,726	39.2	3,360,459	
27	NGV Fuel - Stations	5,704	38.6	220,174	6,406	38.6	247,272	
28								
29	Sched. 22, Burrard, Centra Gas, SCP Third Party Rev.	42,916	39.2	1,682,307	43,398	39.2	1,701,202	
30								
31								
32	Total Gas Sales	1,319,201	35.1	46,254,802	1,340,210	35.1	46,990,861	
33	Other Revenues							
34	Late Payment Charges	4,929	26.7	131,604	4,975	26.7	132,833	- Tab 12, Page 2
35	Returned Cheque Charges	198	31.8	6,296	198	31.8	6,296	- Tab 12, Page 2
36	Connection Charges	4,439	36.8	163,355	4,484	36.7	164,563	- Tab 12, Page 2
37	Other Utility Income	1,006	35.1	35,311	1,026	35.1	36,013	
38								
39								
40	Total	$1,329,773	35.0	$46,591,368	$1,350,893	35.0	$47,330,566	

BC GAS UTILITY LTD.

CASH WORKING CAPITAL
LAG TIME IN PAYMENT OF EXPENSES
FOR THE YEARS ENDING DECEMBER 31, 2003 TO 2005
($000)

Line No.	Particulars	2003 Amount	2003 Lag Days Expense to Payment	2003 Dollar Days	2004 Amount	2004 Lag Days Expense to Payment	2004 Dollar Days	2005 Amount	2005 Lag Days Expense to Payment	2005 Dollar Days	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	EXPENSES										
2											
3	Operating And Maintenance										
4	Expenses	$158,319	19.3	$3,055,557	$164,864	19.3	$3,181,875	$179,936	19.3	$3,472,765	- Tab 2, Pages 2 & 2.1
5											
6	Gas Purchases	759,117	40.7	30,885,559	766,309	40.7	31,178,165	773,414	40.7	31,467,231	- Tab 2, Pages 2 & 2.1
7	Taxes Other Than Income										
8	Property Taxes	41,213	4.0	164,852	41,213	4.0	164,852	41,213	4.0	164,852	- Tab 10, Page 2
9	Franchise Fees	6,848	347.9	2,382,742	6,993	347.9	2,432,925	7,131	347.9	2,481,172	
10	Corporate Capital Tax	0	59.8	0	0	59.8	0	0	59.8	0	- Tab 10, Page 2
11	Goods and Services Tax	86,548	42.1	3,641,104	88,403	42.1	3,719,108	89,792	42.1	3,777,543	- Tab 5, Page 6
12	S. S. Tax	33,602	43.6	1,463,579	34,250	43.6	1,491,808	34,480	43.6	1,501,796	- Tab 5, Page 6
13	Income Tax	34,749	15.2	528,185	37,302	15.2	566,990	40,520	15.2	615,904	- Tab 2, Pages 3 & 3.1
14											
15	Total	1,120,396	37.6	42,121,578	1,139,334	37.5	42,735,723	1,166,486	37.3	43,481,263	
16											
17	EXPENSES, REVISED RATES										
18											
19	Increase in										
20	Franchise Fees	87	347.9	30,267	59	347.9	20,526	107	347.9	37,225	
21	Income Taxes	5,602	15.2	85,150	3,617	15.2	54,978	6,545	15.2	99,484	- Tab 2, Pages 3 & 3.1
22	Corporate Capital Tax	0	59.8	0	0	59.8	0	0	59.8	0	
23											
24	Total	$1,126,085	37.5	$42,236,995	$1,143,010	37.5	$42,811,227	$1,173,138	37.2	$43,617,972	

BC GAS UTILITY LTD.

CASH WORKING CAPITAL
LAG TIME IN PAYMENT OF EXPENSES
FOR THE YEARS ENDING DECEMBER 31, 2006 AND 2007
($000)

		2006			2007			
Line No.	Particulars	Amount	Lag Days Expense to Payment	Dollar Days	Amount	Lag Days Expense to Payment	Dollar Days	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	EXPENSES							
2								
3	Operating And Maintenance							
4	Expenses	$188,034	19.3	$3,629,056	$195,484	19.3	$3,772,841	- Tab 2, Page 2.2
5								
6	Gas Purchases	780,607	40.7	31,759,895	787,685	40.7	32,047,894	- Tab 2, Page 2.2
7	Taxes Other Than Income							
8	Property Taxes	41,213	4.0	164,852	41,213	4.0	164,852	- Tab 10, Page 2
9	Franchise Fees	7,287	347.9	2,535,244	7,418	347.9	2,580,567	
10	Corporate Capital Tax	0	59.8	0	0	59.8	0	- Tab 10, Page 2
11	Goods and Services Tax	91,939	42.1	3,867,851	93,757	42.1	3,944,337	- Tab 5, Page 6.1
12	S. S. Tax	35,027	43.6	1,525,610	35,453	43.6	1,544,192	- Tab 5, Page 6.1
13	Income Tax	43,890	15.2	667,128	46,359	15.2	704,657	- Tab 2, Page 3.2
14								
15	Total	1,187,997	37.2	44,149,636	1,207,369	37.1	44,759,340	
16								
17	EXPENSES, REVISED RATES							
18								
19	Increase in							
20	Franchise Fees	79	347.9	27,484	51	347.9	17,743	
21	Income Taxes	4,931	15.2	74,951	3,143	15.2	47,774	- Tab 2, Page 3.2
22	Corporate Capital Tax	0	59.8	0	0	59.8	0	
23								
24	Total	$1,193,007	37.1	$44,252,071	$1,210,563	37.0	$44,824,857	

Line No.	Particulars	2003 Terajoules Core and Non-Core	2003 Bypass and Special Rates	2003 Total	2004 Terajoules Core and Non-Core	2004 Bypass and Special Rates	2004 Total	2005 Terajoules Core and Non-Core	2005 Bypass and Special Rates	2005 Total
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	SALES									
2	Schedule 1 - Residential	75,045.4	0.0	75,045.4	75,952.1	0.0	75,952.1	76,823.5	0.0	76,823.5
3	Schedule 2 - Small Commercial	23,809.3	0.0	23,809.3	23,951.8	0.0	23,951.8	24,079.1	0.0	24,079.1
4	Schedule 3 - Large Commercial	20,078.5	0.0	20,078.5	20,188.5	0.0	20,188.5	20,288.1	0.0	20,288.1
5										
6	Total Schedules 1, 2 and 3	118,933.2	0.0	118,933.2	120,092.4	0.0	120,092.4	121,190.7	0.0	121,190.7
7										
8	Schedule 4 - Seasonal Service	146.3	0.0	146.3	146.3	0.0	146.3	146.3	0.0	146.3
9	Schedule 5 - General Firm Service	6,279.8	0.0	6,279.8	6,294.3	0.0	6,294.3	6,319.2	0.0	6,319.2
10										
11	Industrials									
12	Schedule 7 - Interruptible	118.2	0.0	118.2	114.1	0.0	114.1	116.3	0.0	116.3
13										
14	Schedule 10	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
15										
16	Total Industrials	118.2	0.0	118.2	114.1	0.0	114.1	116.3	0.0	116.3
17										
18	Schedule 6 - N G V Fuel - Stations	557.0	0.0	557.0	575.0	0.0	575.0	633.9	0.0	633.9
19										
20	Total Sales	126,034.5	0.0	126,034.5	127,222.1	0.0	127,222.1	128,406.4	0.0	128,406.4
21										
22	TRANSPORTATION SERVICE									
23	Schedule 22 - Firm Service	9,879.2	38,339.7	48,218.9	9,776.7	42,900.0	52,676.7	9,915.3	42,704.4	52,619.7
24	- Interruptible Service	15,381.4	2,258.9	17,640.3	15,501.8	2,445.7	17,947.5	15,700.1	2,578.7	18,278.8
25	Schedule 23 - Large Commercial	3,816.2	0.0	3,816.2	3,816.2	0.0	3,816.2	3,816.2	0.0	3,816.2
26	Schedule 25 - Firm Service	10,491.7	1,406.9	11,898.6	10,462.3	1,436.2	11,898.5	10,423.3	1,465.5	11,888.8
27	Schedule 27 - Interruptible	6,082.6	0.0	6,082.6	6,132.4	0.0	6,132.4	6,178.8	0.0	6,178.8
28	Centra B.C. (PCEC)	0.0	36,553.3	36,553.3	0.0	39,357.3	39,357.3	0.0	42,161.5	42,161.5
29	Columbia Service Area - Byron Creek	0.0	158.7	158.7	0.0	158.7	158.7	0.0	158.7	158.7
30										
31	Total Transportation Service	45,651.1	78,717.5	124,368.6	45,689.4	86,297.9	131,987.3	46,033.7	89,068.8	135,102.5
32										
33	TOTAL SALES AND TRANSPORTATION SERVICE	171,685.6	78,717.5	250,403.1	172,911.5	86,297.9	259,209.4	174,440.1	89,068.8	263,508.9

BC GAS UTILITY LTD.
GAS SALES AND TRANSPORTATION VOLUMES
FOR THE YEARS ENDING DECEMBER 31, 2006 AND 2007

Line No.	Particulars	2006 Terajoules Core and Non-Core	2006 Terajoules Bypass and Special Rates	2006 Terajoules Total	2007 Terajoules Core and Non-Core	2007 Terajoules Bypass and Special Rates	2007 Terajoules Total
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	SALES						
2	Schedule 1 - Residential	77,721.7	0.0	77,721.7	78,648.7	0.0	78,648.7
3	Schedule 2 - Small Commercial	24,186.9	0.0	24,186.9	24,286.8	0.0	24,286.8
4	Schedule 3 - Large Commercial	20,378.3	0.0	20,378.3	20,457.2	0.0	20,457.2
5							
6	Total Schedules 1, 2 and 3	122,286.9	0.0	122,286.9	123,392.7	0.0	123,392.7
7							
8	Schedule 4 - Seasonal Service	146.3	0.0	146.3	146.3	0.0	146.3
9	Schedule 5 - General Firm Service	6,345.4	0.0	6,345.4	6,357.1	0.0	6,357.1
10							
11	Industrials						
12	Schedule 7 - Interruptible	117.4	0.0	117.4	118.4	0.0	118.4
13							
14	Schedule 10	0.0	0.0	0.0	0.0	0.0	0.0
15							
16	Total Industrials	117.4	0.0	117.4	118.4	0.0	118.4
17							
18	Schedule 6 - N G V Fuel - Stations	702.5	0.0	702.5	786.9	0.0	786.9
19							
20	Total Sales	129,598.5	0.0	129,598.5	130,801.4	0.0	130,801.4
21							
22	TRANSPORTATION SERVICE						
23	Schedule 22 - Firm Service	9,913.4	47,926.0	57,839.4	9,977.4	30,161.0	40,138.4
24	- Interruptible Service	15,878.5	2,776.0	18,654.5	15,994.9	3,083.3	19,078.2
25	Schedule 23 - Large Commercial	3,816.2	0.0	3,816.2	3,816.2	0.0	3,816.2
26	Schedule 25 - Firm Service	10,476.5	1,464.1	11,940.6	10,484.7	1,465.6	11,950.3
27	Schedule 27 - Interruptible Service	6,209.2	0.0	6,209.2	6,203.6	0.0	6,203.6
28	Centra B.C. (PCEC)	0.0	45,065.6	45,065.6	0.0	47,869.8	47,869.8
29	Columbia Service Area - Byron Creek	0.0	158.7	158.7	0.0	158.7	158.7
30							
31	Total Transportation Service	46,293.8	97,390.4	143,684.2	46,476.8	82,738.4	129,215.2
32							
33	TOTAL SALES AND TRANSPORTATION SERVICE	175,892.3	97,390.4	273,282.7	177,278.2	82,738.4	260,016.6

BC GAS UTILITY LTD.
SALES REVENUES
FOR THE YEARS ENDING DECEMBER 31, 2003 to 2007

($000)

Line No.	Particulars	2003 Gas Sales Revenue At 2002 Approved Rates Core and Non-Core	Bypass and Special Rates	Total	2004 Gas Sales Revenue At 2003 Rates Core and Non-Core	Bypass and Special Rates	Total	2005 Gas Sales Revenue At 2004 Rates Core and Non-Core	Bypass and Special Rates	Total
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	SALES									
2	Schedule 1 - Residential	$724,336	$0	$724,336	$743,520	$0	$743,520	$758,583	$0	$758,583
3	Schedule 2 - Small Commercial	214,477	0	214,477	218,369	0	218,369	221,157	0	221,157
4	Schedule 3 - Large Commercial	162,163	0	162,163	164,708	0	164,708	166,553	0	166,553
5										
6	Total Schedules 1, 2 and 3	1,100,976	0	1,100,976	1,126,597	0	1,126,597	1,146,293	0	1,146,293
7										
8	Schedule 4 - Seasonal Service	1,008	0	1,008	1,010	0	1,010	1,014	0	1,014
9	Schedule 5 - General Firm Service	46,828	0	46,828	47,024	0	47,024	47,438	0	47,438
10		47,836	0	47,836	48,034	0	48,034	48,452	0	48,452
11	Industrials									
12	Schedule 7 - Interruptible	820	0	820	794	0	794	812	0	812
13										
14	Schedule 10	0	0	0	0	0	0	0	0	0
15										
16										
17	Total Industrials	820	0	820	794	0	794	812	0	812
18										
19	Schedule 6 - N G V Fuel - Stations	4,377	0	4,377	4,536	0	4,536	5,033	0	5,033
20										
21	Total Sales	1,154,009	0	1,154,009	1,179,961	0	1,179,961	1,200,590	0	1,200,590
22										
23	TRANSPORTATION SERVICE									
24	Schedule 22 - Firm Service	7,157	11,415	18,572	7,236	11,415	18,651	7,418	11,415	18,833
25	- Interruptible Service	9,982	0	9,982	10,052	0	10,052	10,412	0	10,412
26	Schedule 23 - Large Commercial	8,277	0	8,277	8,589	0	8,589	8,782	0	8,782
27	Schedule 25 - Firm Service	15,999	755	16,754	16,134	757	16,891	16,475	759	17,234
28	Schedule 27 - Interruptible	6,064	0	6,064	6,163	0	6,163	6,340	0	6,340
29	Centra B.C. (PCEC)	0	0	0	0	0	0	0	0	0
30	Columbia Service Area - Byron Creek	0	0	0	0	0	0	0	0	0
31										
32	Total Transportation Service	47,479	12,170	59,649	48,174	12,172	60,346	49,427	12,174	61,601
33										
34	TOTAL SALES AND TRANSPORTATION SERVICE	$1,201,488	$12,170	$1,213,658	$1,228,135	$12,172	$1,240,307	$1,250,017	$12,174	$1,262,191

($000)

Line No.	Particulars	2006 Gas Sales Revenue At 2005 Rates			2007 Gas Sales Revenue At 2006 Rates		
		Core and Non-Core	Bypass and Special Rates	Total	Core and Non-Core	Bypass and Special Rates	Total
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	SALES						
2	Residential / Residential	$779,314	$0	$779,314	$797,403	$0	$797,403
3	Schedule 2 - Small Commercial	225,073	0	225,073	228,162	0	228,162
4	Schedule 3 - Large Commercial	169,155	0	169,155	171,178	0	171,178
5							
6	Total Schedules 1, 2 and 3	1,173,542	0	1,173,542	1,196,743	0	1,196,743
7							
8	Schedule 4 - Seasonal Service	1,021	0	1,021	1,027	0	1,027
9	Schedule 5 - General Firm Service	48,066	0	48,066	48,482	0	48,482
10		49,087	0	49,087	49,509	0	49,509
11	Industrials						
12	Schedule 7 - Interruptible	827	0	827	836	0	836
13							
14	Schedule 10	0	0	0	0	0	0
15							
16							
17	Total Industrials	827	0	827	836	0	836
18							
19	Schedule 6 - N G V Fuel - Stations	5,651	0	5,651	6,368	0	6,368
20							
21	Total Sales	1,229,107	0	1,229,107	1,253,456	0	1,253,456
22							
23	TRANSPORTATION SERVICE						
24	Schedule 22 - Firm Service	7,713	11,415	19,128	7,935	11,465	19,400
25	- Interruptible Service	10,945	0	10,945	11,337	0	11,337
26	Schedule 23 - Large Commercial	9,129	0	9,129	9,383	0	9,383
27	Schedule 25 - Firm Service	17,151	759	17,910	17,633	759	18,392
28	Schedule 27 - Interruptible Service	6,613	0	6,613	6,791	0	6,791
29	Centra B.C. (PCEC)	0	0	0	0	0	0
30	Columbia Service Area - Byron Creek	0	0	0	0	0	0
31							
32	Total Transportation Service	51,551	12,174	63,725	53,079	12,224	65,303
33							
34	TOTAL SALES AND TRANSPORTATION SERVICE	$1,280,658	$12,174	$1,292,832	$1,306,535	$12,224	$1,318,759

REVENUE UNDER EXISTING RATES AND REVISED RATES
FOR THE YEAR ENDING DECEMBER 31, 2003
($000)

Line No.	Particulars	Terajoules	Revenue -- At Existing Rates -- Average $/GJ	Revenue -- At Existing Rates -- Revenue ($000)	Gross Margin -- At Existing Rates -- Average $/GJ	Gross Margin -- At Existing Rates -- Revenue ($000)	Increase (RSAM Classes 3.80%, Other Classes 0.95% of Margin) $/GJ	Increase (RSAM Classes 3.80%, Other Classes 0.95% of Margin) Revenue ($000)	Average Number of Customers	Revenue ---- Revised Rates ---- Average $/GJ	Revenue ---- Revised Rates ---- Revenue ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Core and Non-Core Sales										
2											
3	Schedule 1 - Residential	75,045.4	$9.652	$724,336	$3.6137	$271,192	$0.1374	$10,313	694,783	$9.789	$734,649
4	Schedule 2 - Small Commercial	23,809.3	9.008	214,477	2.8684	68,295	0.1091	2,597	73,231	9.117	217,074
5	Schedule 3 - Large Commercial	20,078.5	8.076	162,163	2.1665	43,500	0.0824	1,654	5,402	8.159	163,817
6											
7	Total Schedules 1 , 2 and 3	118,933.2		1,100,976		382,987		14,564			1,115,540
8											
9											
10	Schedule 4 - Seasonal Service	146.3	6.890	1,008	1.2577	184	0.0137	2	20	6.904	1,010
11	Schedule 5 - General Firm Service	6,279.8	7.457	46,828	1.8079	11,353	0.0172	108	514	7.474	46,936
12											
13	Industrials										
14	Schedule 7 - Interruptible	118.2	6.937	820	1.2860	152	0.0085	1	6	6.946	821
15											
16	Schedule 10 - Interruptible	0.0	0.000	0	0.0000	0	0.0000	0	0	0.000	0
17											
18	Total Industrials	118.2		820		152		1			821
19											
20											
21	Schedule 6 - N G V Fuel - Stations	557.0	7.858	4,377	2.5045	1,395	0.0251	14	53	7.883	4,391
22											
23											
24	Total Core and Non-Core Sales	126,034.5		1,154,009		396,071		14,689	774,009		1,168,698
25											
26	Transportation Service										
27	Schedule 22 - Firm Service	9,879.2	0.724	7,157	0.7222	7,135	0.0068	67	11	0.731	7,224
28	- Interruptible Service	15,381.4	0.649	9,982	0.6243	9,603	0.0059	91	34	0.655	10,073
29	Schedule 23 - Large Commercial	3,816.2	2.169	8,277	2.1506	8,207	0.0818	312	580	2.251	8,589
30	Schedule 25 - Firm Service	10,491.7	1.525	15,999	1.5090	15,832	0.0143	150	398	1.539	16,149
31	Schedule 27 - Interruptible Service	6,082.6	0.997	6,064	0.9718	5,911	0.0092	56	92	1.006	6,120
32											
33	Total Core and Non-Core T-Service	45,651.1		47,479		46,688		676	1,115		48,155
34											
35											
36	Total Core and Non-Core Sales and T-Service	171,685.6		$1,201,488		$442,759		$15,365	775,124		$1,216,853

BC GAS UTILITY LTD.

REVENUE UNDER EXISTING RATES AND REVISED RATES
FOR THE YEAR ENDING DECEMBER 31, 2003
($000)

			Revenue -- At Existing Rates --		Gross Margin -- At Existing Rates --		Increase: RSAM Classes 3.80%, Other Classes 0.95% of Margin			Revenue ---- Revised Rates ----	
Line No.	Particulars	Terajoules	Average $/GJ	Revenue ($000)	Average $/GJ	Revenue ($000)	$/GJ	Revenue ($000)	Average Number of Customers	Average $/GJ	Revenue ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Bypass and Special Rates										
2											
3	Bypass and Special Rates - Sales										
4	Residential - Option A	0.0	$0.000	$0	$0.0000	$0	$0.000	$0	0	$0.000	$0
5	Schedule 4 - Seasonal Service	0.0	0.000	0	0.0000	0	0.000	0	0	0.000	0
6	Schedule 5 - General Firm Service	0.0	0.000	0	0.0000	0	0.000	0	0	0.000	0
7	Industrials										
8	Schedule 7 - Interruptible	0.0	0.000	0	0.0000	0	0.000	0	0	0.000	0
9											
10	Schedule 10 - Interruptible	0.0	0.000	0	0.0000	0	0.000	0	0	0.000	0
11											
12	Total Industrials	0.0		0		0		0			0
13											
14	Schedule 6 - N G V Fuel - Stations	0.0	0.000	0	0.000	0		0	0	0.000	0
15											
16											
17	Total Bypass and Special Rates Sales	0.0		0		0		0	0		0
18											
19	Bypass and Special Rates Transportation Service										
20	Centra B.C. (PCEC)	36,553.3	0.000	0	0.100	3,668	0	0	1	0.000	0
21	Schedule 22 - Firm Service	12,330.4	0.125	1,544	0.131	1,610	0	0	1	0.125	1,544
22	Schedule 22 - Interruptible	2,258.9	0.000	0	0.006	13	0	0	8	0.000	0
23	Schedule 25 - Interruptible	1,406.9	0.537	755	0.542	763	0	0	7	0.537	755
24	Columbia - Byron Creek	158.7	0.000	0	(0.025)	(4)	0	0	1	0.000	0
25	Burrard Transportation - Firm	26,009.3	0.380	9,871	0.372	9,675	0	0	1	0.380	9,871
26	Total Bypass and Special Rates T- Service	78,717.5		12,170		15,725		0	19		12,170
27											
28	Total Bypass and Special Rates Sales and										
29	Transportation Service	78,717.5		12,170		15,725		0	19		12,170
30											
31											
32	TOTAL SALES AND TRANSPORTATION SERVICE	250,403.1		$1,213,658		$458,484		$15,365	775,143		$1,229,023

BC GAS UTILITY LTD.

REVENUE UNDER PROPOSED 2003 RATES AND REVISED RATES
FOR THE YEAR ENDING DECEMBER 31, 2004
($000)

Line No.	Particulars	Terajoules	Revenue -- At 2003 Rates -- Average $/GJ	Revenue -- At 2003 Rates -- Revenue ($000)	Gross Margin -- At 2003 Rates -- Average $/GJ	Gross Margin -- At 2003 Rates -- Revenue ($000)	Increase 2.27% $/GJ	Increase of Margin Revenue ($000)	Average Number of Customers	Revenue ---- Revised Rates ---- Average $/GJ	Revenue ---- Revised Rates ---- Revenue ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Core and Non-Core Sales										
2	Captive Sales										
3	Schedule 1 - Residential	75,952.1	$9.789	$743,520	$3.7511	$284,903	$0.0850	$6,457	703,175	$9.874	$749,977
4	Schedule 2 - Small Commercial	23,951.8	9.117	218,369	2.9776	71,319	0.0675	1,617	73,673	9.185	219,986
5	Schedule 3 - Large Commercial	20,188.5	8.159	164,708	2.2488	45,399	0.0510	1,029	5,431	8.210	165,737
6											
7	Total Schedules 1 , 2 and 3	120,092.4		1,126,597		401,621		9,103			1,135,700
8											
9											
10	Schedule 4 - Seasonal Service	146.3	6.904	1,010	1.2714	186	0.0342	5	20	6.938	1,015
11	Schedule 5 - General Firm Service	6,294.3	7.471	47,024	1.8216	11,466	0.0413	260	514	7.512	47,284
12											
13	Industrials										
14	Schedule 7 - Interruptible	114.1	6.959	794	1.3146	150	0.0351	4	6	6.994	798
15											
16	Schedule 10 - Interruptible	0.0	0.000	0	0.0000	0	0.0000	0	0	0.000	0
17											
18	Total Industrials	114.1		794		150		4			798
19											
20											
21	Schedule 6 - N G V Fuel - Stations	575.0	7.889	4,536	2.5339	1,457	0.0574	33	53	7.946	4,569
22	- VRA's	0.0	0.000	0	0.0000	0	0.0000	0	0	0.000	0
23											
24	Total Captive Sales	127,222.1		1,179,961		414,880		9,405	782,872		1,189,366
25											
26	Captive Transportation Service										
27	Schedule 22 - Firm Service	9,776.7	0.740	7,236	0.7384	7,219	0.0167	163	16	0.757	7,399
28	- Interruptible Service	15,501.8	0.648	10,052	0.6238	9,670	0.0142	220	29	0.662	10,272
29	Schedule 23 - Large Commercial	3,816.2	2.251	8,589	2.2323	8,519	0.0506	193	580	2.302	8,782
30	Schedule 25 - Firm Service	10,462.3	1.542	16,134	1.5261	15,967	0.0346	362	398	1.577	16,496
31	Schedule 27 - Interruptible Service	6,132.4	1.005	6,163	0.9799	6,009	0.0223	137	92	1.027	6,300
32											
33	Total Captive Transportation Service	45,689.4		48,174		47,384		1,075	1,115		49,249
34											
35	Total Captive Sales and										
36	Transportation Service	172,911.5		$1,228,135		$462,264		$10,480	783,987		$1,238,615

REVENUE UNDER PROPOSED 2003 RATES AND REVISED RATES
FOR THE YEAR ENDING DECEMBER 31, 2004
($000)

Line No.	Particulars	Terajoules	Revenue -- At 2003 Rates -- Average $/GJ	Revenue -- At 2003 Rates -- Revenue ($000)	Gross Margin -- At 2003 Rates -- Average $/GJ	Gross Margin -- At 2003 Rates -- Revenue ($000)	Increase 2.27% of Margin $/GJ	Increase 2.27% of Margin Revenue ($000)	Average Number of Customers	Revenue ---- Revised Rates ---- Average $/GJ	Revenue ---- Revised Rates ---- Revenue ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Bypass and Special Rates										
2											
3	Bypass and Special Rates - Sales										
4	Residential - Option A	0.0	$0.000	$0	$0.0000	$0	$0.000	$0	0	$0.000	$0
5	Schedule 4 - Seasonal Service	0.0	0.000	0	0.0000	0	0.000	0	0	0.000	0
6	Schedule 5 - General Firm Service	0.0	0.000	0	0.0000	0	0.000	0	0	0.000	0
7	Industrials										
8	Schedule 7 - Interruptible	0.0	0.000	0	0.0000	0	0.000	0	0	0.000	0
9											
10	Schedule 10 - Interruptible	0.0	0.000	0	0.0000	0	0.000	0	0	0.000	0
11											
12	Total Large Industrial	0.0		0		0		0			0
13											
14	Schedule 6 - N G V Fuel - Stations	0.0	0.000	0	0.0000	0	0	0	0	0.000	0
15	- VRA's	0.0	0.000	0	0.0000	0	0	0	0	0.000	0
16											
17	Total Non-Captive Sales	0.0		0		0		0	0		0
18											
19	Non-Captive Transportation Service										
20	Centra B.C. (PCEC)	39,357.3	0.000	0	0.0952	3,745	0	0	1	0.000	0
21	Schedule 22 - Firm Service	12,535.2	0.123	1,544	0.1284	1,610	0	0	1	0.123	1,544
22	Schedule 22 - Interruptible	2,445.7	0.000	0	0.0061	15	0	0	8	0.000	0
23	Schedule 25 - Interruptible	1,436.2	0.527	757	0.5334	766	0	0	7	0.527	757
24	Columbia - Byron Creek	158.7	0.000	0	(0.0252)	(4)	0	0	1	0.000	0
25	Burrard Transportation - Firm	30,364.8	0.325	9,871	0.3176	9,643	0	0	1	0.325	9,871
26	Total Non-Captive Transportation Service	86,297.9		12,172		15,775		0	19		12,172
27											
28	Total Non-Captive Sales and										
29	Transportation Service	86,297.9		12,172		15,775		0	19		12,172
30											
31	TOTAL CAPTIVE AND NON-CAPTIVE SALES AND										
32	TRANSPORTATION SERVICE	259,209.4		$1,240,307		$478,039		$10,480	784,006		$1,250,787

BC GAS UTILITY LTD.

REVENUE UNDER PROPOSED 2004 RATES AND REVISED RATES
FOR THE YEAR ENDING DECEMBER 31, 2005
($000)

Line No.	Particulars	Terajoules	Revenue -- At 2004 Rates -- Average $/GJ	Revenue -- At 2004 Rates -- Revenue ($000)	Gross Margin -- At 2004 Rates -- Average $/GJ	Gross Margin -- At 2004 Rates -- Revenue ($000)	Increase 3.98% $/GJ	of Margin Revenue ($000)	Average Number of Customers	Revenue ---- Revised Rates ---- Average $/GJ	Revenue ---- Revised Rates ---- Revenue ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	CAPTIVE										
2	Captive Sales										
3	Schedule 1 - Residential	76,823.5	$9.874	$758,583	$3.8362	$294,707	$0.1526	$11,724	711,256	$10.027	$770,307
4	Schedule 2 - Small Commercial	24,079.1	9.185	221,157	3.0454	73,330	0.1211	2,916	74,084	9.306	224,073
5	Schedule 3 - Large Commercial	20,288.1	8.209	166,553	2.2999	46,660	0.0915	1,856	5,458	8.301	168,409
6											
7	Total Schedules 1 , 2 and 3	121,190.7		1,146,293		414,697		16,496			1,162,789
8											
9											
10	Schedule 4 - Seasonal Service	146.3	6.931	1,014	1.2987	190	0.0547	8	20	6.986	1,022
11	Schedule 5 - General Firm Service	6,319.2	7.507	47,438	1.8580	11,741	0.0737	466	514	7.581	47,904
12											
13	Industrials										
14	Schedule 7 - Interruptible	116.3	6.982	812	1.3328	155	0.0516	6	6	7.034	818
15											
16	Schedule 10 - Interruptible	0.0	0.000	0	0.0000	0	0.0000	0	0	0.000	0
17											
18	Total Industrials	116.3		812		155		6			818
19											
20											
21	Schedule 6 - N G V Fuel - Stations	633.9	7.940	5,033	2.5840	1,638	0.1025	65	53	8.043	5,098
22	- VRA's	0.0	0.000	0	0.0000	0	0.0000	0	0	0.000	0
23											
24	Total Captive Sales	128,406.4		1,200,590		428,421		17,041	791,391		1,217,631
25											
26	Captive Transportation Service										
27	Schedule 22 - Firm Service	9,915.3	0.748	7,418	0.7466	7,403	0.0297	294	16	0.778	7,712
28	- Interruptible Service	15,700.1	0.663	10,412	0.6390	10,032	0.0254	399	29	0.688	10,811
29	Schedule 23 - Large Commercial	3,816.2	2.301	8,782	2.2829	8,712	0.0909	347	580	2.392	9,129
30	Schedule 25 - Firm Service	10,423.3	1.581	16,475	1.5646	16,308	0.0623	649	398	1.643	17,124
31	Schedule 27 - Interruptible Service	6,178.8	1.026	6,340	1.0010	6,185	0.0398	246	92	1.066	6,586
32											
33	Total Captive Transportation Service	46,033.7		49,427		48,640		1,935	1,115		51,362
34											
35											
36	Total Captive Sales and Transportation Service	174,440.1		$1,250,017		$477,061		$18,976	792,506		$1,268,993

BC GAS UTILITY LTD.

REVENUE UNDER PROPOSED 2004 RATES AND REVISED RATES
FOR THE YEAR ENDING DECEMBER 31, 2005
($000)

			Revenue -- At 2004 Rates --		Gross Margin -- At 2004 Rates --		Increase 3.98%	of Margin		Revenue ---- Revised Rates ----	
Line No.	Particulars	Terajoules	Average $/GJ	Revenue ($000)	Average $/GJ	Revenue ($000)	$/GJ	Revenue ($000)	Average Number of Customers	Average $/GJ	Revenue ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Bypass and Special Rates										
2											
3	Bypass and Special Rates - Sales										
4	Residential - Option A	0.0	$0.000	$0	$0.0000	$0	$0.000	$0	0	$0.000	$0
5	Schedule 4 - Seasonal Service	0.0	0.000	0	0.0000	0	0.000	0	0	0.000	0
6	Schedule 5 - General Firm Service	0.0	0.000	0	0.0000	0	0.000	0	0	0.000	0
7	Industrials										
8	Schedule 7 - Interruptible	0.0	0.000	0	0.0000	0	0.000	0	0	0.000	0
9											
10	Schedule 10 - Interruptible	0.0	0.000	0	0.0000	0	0.000	0	0	0.000	0
11											
12	Total Large Industrial	0.0		0		0		0			0
13											
14	Schedule 6 - N G V Fuel - Stations	0.0	0.000	0	0.0000	0		0	0	0.000	0
15	- VRA's	0.0	0.000	0	0.0000	0		0	0	0.000	0
16											
17	Total Non-Captive Sales	0.0		0		0		0	0		0
18											
19	Non-Captive Transportation Service										
20	Centra B.C. (PCEC)	42,161.5	0.000	0	0.0904	3,811	0	0	1	0.000	0
21	Schedule 22 - Firm Service	12,545.5	0.123	1,544	0.1283	1,610	0	0	1	0.123	1,544
22	Schedule 22 - Interruptible	2,578.7	0.000	0	0.0058	15	0	0	8	0.000	0
23	Schedule 25 - Interruptible	1,465.5	0.518	759	0.5241	768	0	0	7	0.518	759
24	Columbia - Byron Creek	158.7	0.000	0	(0.0252)	(4)	0	0	1	0.000	0
25	Burrard Transportation - Firm	30,158.9	0.327	9,871	0.3198	9,644	0	0	1	0.327	9,871
26	Total Non-Captive Transportation Service	89,068.8		12,174		15,844		0	19		12,174
27											
28	Total Non-Captive Sales and										
29	Transportation Service	89,068.8		12,174		15,844		0	19		12,174
30											
31	TOTAL CAPTIVE AND NON-CAPTIVE SALES AND										
32	TRANSPORTATION SERVICE	263,508.9		$1,262,191		$492,905		$18,976	792,525		$1,281,167

BC GAS UTILITY LTD.

REVENUE UNDER PROPOSED 2005 RATES AND REVISED RATES
FOR THE YEAR ENDING DECEMBER 31, 2006
($000)

Line No.	Particulars	Terajoules	Revenue -- At 2005 Rates -- Average $/GJ	Revenue -- At 2005 Rates -- Revenue ($000)	Gross Margin -- At 2005 Rates -- Average $/GJ	Gross Margin -- At 2005 Rates -- Revenue ($000)	Increase 2.805% of Margin $/GJ	Increase 2.805% of Margin Revenue ($000)	Average Number of Customers	Revenue ---- Revised Rates ---- Average $/GJ	Revenue ---- Revised Rates ---- Revenue ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	CAPTIVE										
2	Captive Sales										
3	Schedule 1 - Residential	77,721.7	$10.027	$779,314	$3.9888	$310,015	$0.1118	$8,693	719,574	$10.139	$788,007
4	Schedule 2 - Small Commercial	24,186.9	9.306	225,073	3.1665	76,589	0.0888	2,148	74,425	9.395	227,221
5	Schedule 3 - Large Commercial	20,378.3	8.301	169,155	2.3914	48,732	0.0671	1,368	5,482	8.368	170,523
6											
7	Schedules 1, 2 and 3	122,286.9		1,173,542		435,336		12,209			1,185,751
8											
9											
10	Schedule 4 - Seasonal Service	146.3	6.979	1,021	1.3465	197	0.0342	5	20	7.013	1,026
11	Schedule 5 - General Firm Service	6,345.4	7.575	48,066	1.9260	12,221	0.0543	342	514	7.629	48,408
12											
13	Industrials										
14	Schedule 7 - Interruptible	117.4	7.044	827	1.3884	163	0.0438	5	6	7.088	832
15											
16	Schedule 10 - Interruptible	0.0	0.000	0	0.0000	0	0.0000	0	0	0.000	0
17											
18	Total Industrials	117.4		827		163		5			832
19											
20											
21	Schedule 6 - N G V Fuel - Stations	702.5	8.044	5,651	2.6890	1,889	0.0922	53	53	8.136	5,704
22	- VRA's	0.0	0.000	0	0.0000	0	0.0000	0	0	0.000	0
23											
24	Total Captive Sales	129,598.5		1,229,107		449,806		12,614	800,074		1,241,721
25											
26	Captive Transportation Service										
27	Schedule 22 - Firm Service	9,913.4	0.778	7,713	0.7766	7,699	0.0222	217	15	0.800	7,930
28	- Interruptible Service	15,878.5	0.689	10,945	0.6653	10,564	0.0192	297	29	0.708	11,242
29	Schedule 23 - Large Commercial	3,816.2	2.392	9,129	2.3738	9,059	0.0666	254	580	2.459	9,383
30	Schedule 25 - Firm Service	10,476.5	1.637	17,151	1.6211	16,983	0.0455	476	398	1.683	17,627
31	Schedule 27 - Interruptible Service	6,209.2	1.065	6,613	1.0399	6,457	0.0297	182	92	1.095	6,795
32											
33	Total Captive Transportation Service	46,293.8		51,551		50,762		1,426	1,114		52,977
34											
35	Total Captive Sales and										
36	Transportation Service	175,892.3		$1,280,658		$500,568		$14,040	801,188		$1,294,698

BC GAS UTILITY LTD.

REVENUE UNDER PROPOSED 2005 RATES AND REVISED RATES
FOR THE YEAR ENDING DECEMBER 31, 2006
($000)

			Revenue -- At 2005 Rates --		Gross Margin -- At 2005 Rates --		Increase 2.80%	Increase of Margin		Revenue ---- Revised Rates ----	
Line No.	Particulars	Terajoules	Average $/GJ	Revenue ($000)	Average $/GJ	Revenue ($000)	$/GJ	Revenue ($000)	Average Number of Customers	Average $/GJ	Revenue ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	NON-CAPTIVE										
2											
3	Non-Captive - Sales										
4	Residential - Option A	0.0	$0.000	$0	$0.0000	$0	$0.000	$0	0	$0.000	$0
5	Schedule 4 - Seasonal Service	0.0	0.000	0	0.0000	0	0.000	0	0	0.000	0
6	Schedule 5 - General Firm Service	0.0	0.000	0	0.0000	0	0.000	0	0	0.000	0
7	Industrials										
8	Schedule 7 - Interruptible	0.0	0.000	0	0.0000	0	0.000	0	0	0.000	0
9											
10	Schedule 10 - Interruptible	0.0	0.000	0	0.0000	0	0.000	0	0	0.000	0
11											
12	Total Large Industrial	0.0		0		0		0			0
13											
14	Schedule 6 - N G V Fuel - Stations	0.0	0.000	0	0.0000	0	0	0	0	0.000	0
15	- VRA's	0.0	0.000	0	0.0000	0	0	0	0	0.000	0
16											
17	Total Non-Captive Sales	0.0		0		0		0	0		0
18											
19	Non-Captive Transportation Service										
20	Centra B.C. (PCEC)	45,065.6	0.000	0	0.0841	3,790	0	0	1	0.000	0
21	Schedule 22 - Firm Service	12,618.9	0.123	1,544	0.1276	1,610	0	0	2	0.122	1,544
22	Schedule 22 - Interruptible	2,776.0	0.000	0	0.0061	17	0	0	8	0.000	0
23	Schedule 25 - Interruptible	1,464.1	0.528	759	0.5246	768	0	0	7	0.518	759
24	Columbia - Byron Creek	158.7	0.000	0	(0.0252)	(4)	0	0	1	0.000	0
25	Burrard Transportation - Firm	35,307.1	0.325	9,871	0.2720	9,605	0	0	1	0.325	9,871
26	Total Non-Captive Transportation Service	97,390.4		12,174		15,786		0	20		12,174
27											
28	Total Non-Captive Sales and										
29	Transportation Service	97,390.4		12,174		15,786		0	20		12,174
30											
31	TOTAL CAPTIVE AND NON-CAPTIVE SALES AND										
32	TRANSPORTATION SERVICE	273,282.7		$1,292,832		$516,354		$14,040	801,208		$1,306,872

BC GAS UTILITY LTD.

REVENUE UNDER PROPOSED 2006 RATES AND REVISED RATES
FOR THE YEAR ENDING DECEMBER 31, 2007
($000)

Line No.	Particulars	Terajoules	Revenue -- At 2006 Rates -- Average $/GJ	Revenue -- At 2006 Rates -- Revenue ($000)	Gross Margin -- At 2006 Rates -- Average $/GJ	Gross Margin -- At 2006 Rates -- Revenue ($000)	Increase 1.76% $/GJ	Increase of Margin Revenue ($000)	Average Number of Customers	Revenue ---- Revised Rates ---- Average $/GJ	Revenue ---- Revised Rates ---- Revenue ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	CAPTIVE										
2	Captive Sales										
3	Schedule 1 - Residential	78,648.7	$0.000	$797,403	$4.1006	$322,505	$0.0720	$5,665	728,135	$0.072	$803,068
4	Schedule 2 - Small Commercial	24,286.8	0.000	228,162	3.2556	79,069	0.0572	1,389	74,750	0.057	229,551
5	Schedule 3 - Large Commercial	20,457.2	0.000	171,178	2.4584	50,291	0.0432	883	5,504	0.043	172,061
6											
7	Total Schedules 1 , 2 and 3	123,392.7		1,196,743		451,865		7,937			1,204,680
8											
9											
10	Schedule 4 - Seasonal Service	146.3	0.000	1,027	1.3876	203	0.0205	3	20	0.021	1,030
11	Schedule 5 - General Firm Service	6,357.1	0.000	48,482	1.9775	12,571	0.0348	221	514	0.035	48,703
12											
13	Industrials										
14	Schedule 7 - Interruptible	118.4	0.000	836	1.4105	167	0.0253	3	6	0.025	839
15											
16	Schedule 10 - Interruptible	0.0	0.000	0	0.0000	0	0.0000	0	0	0.000	0
17											
18	Total Industrials	118.4		836		167		3			839
19											
20											
21	Schedule 6 - N G V Fuel - Stations	786.9	0.117	6,368	2.7373	2,154	0.0483	38	53	0.165	6,406
22	- VRA's	0.0	0.000	0	0.0000	0	0.0000	0	0	0.000	0
23											
24	Total Captive Sales	130,801.4		1,253,456		466,960		8,202	808,982		1,261,658
25											
26	Captive Transportation Service										
27	Schedule 22 - Firm Service	9,977.4	0.795	7,935	0.7940	7,922	0.0139	139	16	0.809	8,074
28	- Interruptible Service	15,994.9	0.709	11,337	0.6849	10,955	0.0120	192	29	0.721	11,529
29	Schedule 23 - Large Commercial	3,816.2	2.459	9,383	2.4404	9,313	0.0430	164	580	2.502	9,547
30	Schedule 25 - Firm Service	10,484.7	1.682	17,633	1.6658	17,465	0.0293	307	398	1.711	17,940
31	Schedule 27 - Interruptible Service	6,203.6	1.095	6,791	1.0697	6,636	0.0189	117	92	1.114	6,908
32											
33	Total Captive Transportation Service	46,476.8		53,079		52,291		919	1,115		53,998
34											
35	Total Captive Sales and										
36	Transportation Service	177,278.2		$1,306,535		$519,251		$9,121	810,097		$1,315,656

REVENUE UNDER PROPOSED 2006 RATES AND REVISED RATES
FOR THE YEAR ENDING DECEMBER 31, 2007
($000)

Line No.	Particulars	Terajoules	Revenue -- At 2006 Rates -- Average $/GJ	Revenue -- At 2006 Rates -- Revenue ($000)	Gross Margin -- At 2006 Rates -- Average $/GJ	Gross Margin -- At 2006 Rates -- Revenue ($000)	Increase 1.76% of Margin $/GJ	Increase 1.76% of Margin Revenue ($000)	Average Number of Customers	Revenue ---- Revised Rates ---- Average $/GJ	Revenue ---- Revised Rates ---- Revenue ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Bypass and Special Rates										
2											
3	Non-Captive - Sales										
4	Residential - Option A	0.0	$0.000	$0	$0.0000	$0	$0.000	$0	0	$0.000	$0
5	Schedule 4 - Seasonal Service	0.0	0.000	0	0.0000	0	0.000	0	0	0.000	0
6	Schedule 5 - General Firm Service	0.0	0.000	0	0.0000	0	0.000	0	0	0.000	0
7	Industrials										
8	Schedule 7 - Interruptible	0.0	0.000	0	0.0000	0	0.000	0	0	0.000	0
9											
10	Schedule 10 - Interruptible	0.0	0.000	0	0.0000	0	0.000	0	0	0.000	0
11											
12	Total Large Industrial	0.0		0		0		0			0
13											
14	Schedule 6 - N G V Fuel - Stations	0.0	0.000	0	0.0000	0	0.000	0	0	0.000	0
15	- VRA's	0.0	0.000	0	0.0000	0	0.000	0	0	0.000	0
16											
17	Total Non-Captive Sales	0.0		0		0		0	0		0
18											
19	Non-Captive Transportation Service										
20	Centra B.C. (PCEC)	47,869.8	0.000	0	0.0788	3,770	0.000	0	1	0.000	0
21	Schedule 22 - Firm Service	12,718.6	0.125	1,594	0.1306	1,661	0.000	0	1	0.125	1,594
22	Schedule 22 - Interruptible	3,083.3	0.000	0	0.0058	18	0.000	0	8	0.000	0
23	Schedule 25 - Interruptible	1,465.6	0.518	759	0.5240	768	0.000	0	7	0.518	759
24	Columbia - Byron Creek	158.7	0.000	0	(0.0252)	(4)	0.000	0	1	0.000	0
25	Burrard Transportation - Firm	17,442.4	0.566	9,871	0.5584	9,740	0.000	0	1		9,871
26	Total Non-Captive Transportation Service	82,738.4		12,224		15,953		0	19		12,224
27											
28	Total Non-Captive Sales and										
29	Transportation Service	82,738.4		12,224		15,953		0	19		12,224
30											
31	TOTAL CAPTIVE AND NON-CAPTIVE SALES AND										
32	TRANSPORTATION SERVICE	260,016.6		$1,318,759		$535,204		$9,121	810,116		$1,327,880

($000)

Line No.	Particulars	2001 Existing Rates	2001 Increase	2001 Total	2003 Existing Rates	2003 Increase	2003 Total	Change
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	SALES							
2	Schedule 1 - Residential	$242,546	$31,818	$274,364	$271,192	$10,313	$281,505	$28,646
3	Schedule 2 - Small Commercial	60,337	7,919	68,256	68,295	2,597	70,892	7,958
4	Schedule 3 - Large Commercial	43,808	5,749	49,557	43,500	1,654	45,154	(308)
5								
6	Total Schedules 1, 2 and 3	346,691	45,486	392,177	382,987	14,564	397,551	36,296
7								
8	Schedule 4 - Seasonal Service	279	37	316	184	2	186	(95)
9	Schedule 5 - General Firm Service	13,268	1,741	15,009	11,353	108	11,461	(1,915)
10								
11	Industrials							
12	Schedule 7 - Interruptible	841	110	951	152	1	153	(689)
13								
14	Burrard Interruptible	0	0	0	0	0	0	0
15								
16								
17	Total Industrials	14,388	1,888	16,276	11,689	111	11,800	(2,699)
18								
19	Schedule 6 - N G V Fuel - Stations	1,637	160	1,797	1,395	14	1,409	(242)
20								
21	Total Sales - Core, Non-Core, Bypass & Special	362,716	47,534	410,250	396,071	14,689	410,760	33,355
22								
23	TRANSPORTATION SERVICE							
24	Schedule 22 - Firm Service	8,940	802	9,742	8,745	67	8,812	(195)
25	- Interruptible Service	17,704	1,095	18,799	9,616	91	9,707	(8,088)
26	Schedule 23 - Firm Service	5,753	755	6,508	8,207	312	8,519	2,454
27	Schedule 25	12,107	1,494	13,601	16,595	150	16,745	4,488
28	Schedule 27	4,639	609	5,248	5,911	56	5,967	1,272
29	Centra B.C. (PCEC)	(330)	0	(330)	(275)	0	(275)	55
30	Byron Creek	151	0	151	(4)	0	(4)	(155)
31	Burrard	0	0	0	9,675	0	9,675	9,675
32	Total Transportation Service	48,964	4,755	53,719	58,470	676	59,146	9,506
33								
34	TOTAL SALES AND TRANSPORTATION SERVICE	411,680	52,289	463,969	454,541	15,365	469,906	42,861
35								
36	BY-PASS AND SPECIAL RATES MARGIN							
37								
38	OTHER REVENUE (See Tab 12, Page 2)							
39	SCP Third Party Revenues	12,730	0	12,730	8,500	0	8,500	(4,230)
40	Centra Gas B.C. (PCEC) Wheeling Charge	3,829	0	3,829	3,943	0	3,943	114
41	Total Other Revenue	16,559	0	16,559	12,443	0	12,443	(4,116)
42								
43	TOTAL GROSS MARGIN (Tab 1, Page 1, Line 13)	$428,239	$52,289	$480,528	$466,984	$15,365	$482,349	$38,745

BC GAS UTILITY LTD.
MARGIN
FOR THE YEARS ENDED DECEMBER 31, 2004 AND 2005
($000)

Line No.	Particulars	2004 Proposed Rates	2004 Increase	2004 Total	2005 Proposed Rates	2005 Increase	2005 Total
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	SALES						
2	Schedule 1 - Residential	$284,903	$6,457	$291,360	$294,707	$11,724	$306,431
3	Schedule 2 - Small Commercial	71,319	1,617	72,936	73,330	2,916	76,246
4	Schedule 3 - Large Commercial	45,399	1,029	46,428	46,660	1,856	48,516
5							
6	Total Schedules 1, 2 and 3	401,621	9,103	410,724	414,697	16,496	431,193
7							
8	Schedule 4 - Seasonal Service	186	5	191	190	8	198
9	Schedule 5 - General Firm Service	11,466	260	11,726	11,741	466	12,207
10							
11	Industrials						
12	Schedule 7 - Interruptible	150	4	154	155	6	161
13							
14	Burrard Interruptible	0	0	0	0	0	0
15							
16							
17	Total Industrials	11,802	269	12,071	12,086	480	12,566
18							
19	Schedule 6 - N G V Fuel - Stations	1,457	33	1,490	1,638	65	1,703
20							
21	Total Sales - Core, Non-Core, Bypass & Special	414,880	9,405	424,285	428,421	17,041	445,462
22							
23	TRANSPORTATION SERVICE						
24	Schedule 22 - Firm Service	8,829	163	8,992	9,013	294	9,307
25	- Interruptible Service	9,685	220	9,905	10,047	399	10,446
26	Schedule 23 - Firm Service	8,519	193	8,712	8,712	347	9,059
27	Schedule 25	16,733	362	17,095	17,076	649	17,725
28	Schedule 27	6,009	137	6,146	6,185	246	6,431
29	Centra B.C. (PCEC)	(296)	0	(296)	(317)	0	(317)
30	Byron Creek	(4)	0	(4)	(4)	0	(4)
31	Burrard	9,643	0	9,643	9,644	0	9,644
32	Total Transportation Service	59,118	1,075	60,193	60,356	1,935	62,291
33							
34	TOTAL SALES AND TRANSPORTATION SERVICE	473,998	10,480	484,478	488,777	18,976	507,753
35							
36	BY-PASS AND SPECIAL RATES MARGIN						
37							
38	OTHER REVENUE (See Tab 12, Page 2)						
39	SCP Third Party Revenues	8,200	0	8,200	8,200	0	8,200
40	Centra Gas B.C. (PCEC) Wheeling Charge	4,041	0	4,041	4,128	0	4,128
41	Total Other Revenue	12,241	0	12,241	12,328	0	12,328
42							
43	TOTAL GROSS MARGIN (Tab 1, Page 1.1, Line 13)	$486,239	$10,480	$496,719	$501,105	$18,976	$520,081

BC GAS UTILITY LTD.
MARGIN
FOR THE YEARS ENDED DECEMBER 31, 2006 AND 2007
($000)

Line No.	Particulars	2006 Proposed Rates	2006 Increase	2006 Total	2007 Proposed Rates	2007 Increase	2007 Total
	(1)	(5)	(6)	(7)	(5)	(6)	(7)
1	SALES						
2	Schedule 1 - Residential	$310,015	$8,693	$318,708	$322,505	$5,665	$328,170
3	Schedule 2 - Small Commercial	76,589	2,148	78,737	79,069	1,389	80,458
4	Schedule 3 - Large Commercial	48,732	1,368	50,100	50,291	883	51,174
5							
6	Total Schedules 1, 2 and 3	435,336	12,209	447,545	451,865	7,937	459,802
7							
8	Schedule 4 - Seasonal Service	197	5	202	203	3	206
9	Schedule 5 - General Firm Service	12,221	342	12,563	12,571	221	12,792
10							
11	Industrials						
12	Schedule 7 - Interruptible	163	5	168	167	3	170
13							
14	Burrard Interruptible	0	0	0	0	0	0
15							
16							
17	Total Industrials	12,581	352	12,933	12,941	227	13,168
18							
19	Schedule 6 - N G V Fuel - Stations	1,889	53	1,942	2,154	38	2,192
20							
21	Total Sales - Core, Non-Core, Bypass & Special	449,806	12,614	462,420	466,960	8,202	475,162
22							
23	TRANSPORTATION SERVICE						
24	Schedule 22 - Firm Service	9,309	217	9,526	9,583	139	9,722
25	- Interruptible Service	10,581	297	10,878	10,973	192	11,165
26	Schedule 23 - Firm Service	9,059	254	9,313	9,313	164	9,477
27	Schedule 25	17,751	476	18,227	18,233	307	18,540
28	Schedule 27	6,457	182	6,639	6,636	117	6,753
29	Centra B.C. (PCEC)	(339)	0	(339)	(360)	0	(360)
30	Byron Creek	(4)	0	(4)	(4)	0	(4)
31	Burrard	9,605	0	9,605	9,740	0	9,740
32	Total Transportation Service	62,419	1,426	63,845	64,114	919	65,033
33							
34	TOTAL SALES AND TRANSPORTATION SERVICE	512,225	14,040	526,265	531,074	9,121	540,195
35							
36	BY-PASS AND SPECIAL RATES MARGIN						
37							
38	OTHER REVENUE (See Tab 12)						
39	SCP Third Party Revenues	8,200	0	8,200	8,200	0	8,200
40	Centra Gas B.C. (PCEC) Wheeling Charge	4,129	0	4,129	4,130	0	4,130
41	Total Other Revenue	12,329	0	12,329	12,330	0	12,330
42							
43	TOTAL GROSS MARGIN (Tab 1, Page 1.2, Line 13)	$524,554	$14,040	$538,594	$543,404	$9,121	$552,525

TARIFF SUPPLEMENT CUSTOMERS

(for Bypass & Other Customers with Special Conditions/Rates/Take or Pay)

Customer Name	Tariff Supplement No.
Silver Star Mountain	A-2
Sun Rivers Services Corp	A-3
Fording Coal Limited	A-4
Beach Place Ventures	C-1
BC Transit	C-2
I.G. Machine & Fibers Ltd.	D-3
Canadian Forest Products	E-1
Dunkley Lumber Ltd.	E-2
Riverside Forest Products	E-3
Slocan Group	E-4
Riverside Forest Products	E-5
Tolko Inustrial Ltd.	E-6
West Fraser Mills	E-8
Interfor	E-10
Crestbrook Forest Ind.	G-1
Trus Joist – Weyerhaeuser	G-2
Chemical Lime Co.	G-3
Canfor – PG Pulp	G-5
Quesnel River Pulp	G-6
Northwood Pulp & Timber	G-7
Cariboo Pulp & Paper	G-8
Husky Oil Operations	G-9
West Fraser Mills	G-10
KPMG Inc. – Celgar	G-11
B.C. Power & Hydro Authority	G-12
Louisiana-Pacific Canada Ltd.	G-13
PG&E Energy Trading	I-1
B.C. Power & Hydro Authority	I-2
Squamish Gas Co. Ltd.	I-3
B.C. Power & Hydro Authority	I-4
International Forest Products Ltd.	I-5
Centra B.C.	

BC GAS UTILITY LTD.
COST OF GAS SOLD
FOR THE YEARS ENDING DECEMBER 31, 2003 to 2007

The cost of gas sold is determined by multiplying forecast sales volumes by the approved forecast unit gas costs for each rate schedule. The unit costs are those approved by Order G-134-01 for firm natural gas sales, interruptible and seasonal rate customers. The gas costs for Revelstoke propane system customers for Schedules 1, 2 and 3 are costed at the rate approved by Order G-130-01. BC Gas will continue to apply, on a basis consistent with established BCUC practice for “flow-through” approval of gas supply costs. The final 2003 gas cost changes will not be known until an application is filed in late November or early December 2002. The 2002 Second Quarter Report under the BCUC Guidelines for Setting Gas Recovery Rates and Managing the Gas Cost Reconciliation Account balance (BCUC Letter No. L-05-01) was filed on June 3, 2002 indicating that a July 1, 2002 rate change is not necessary.

Year		Total Gas Costs ($000)
2003	(Page 2 – 2.2)	$759,117
2004		$766,309
2005		$773,414
2006		$780,607
2007		$787,685

BC GAS UTILITY LTD. - SUMMARY BY SERVICE AREA
COST OF GAS BY RATE SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2003

		Lower Mainland			Inland Including Revelstoke			Columbia			Total
Line No.	Particulars	Energy TJ	Unit Cost $/GJ	Cost of Gas ($000)	Energy TJ	Unit Cost $/GJ	Cost of Gas ($000)	Energy TJ	Unit Cost $/GJ	Cost of Gas ($000)	Cost of Gas ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	CORE AND NON-CORE										
2	Core and Non-Core Sales										
3	Schedule 1 - Residential	54,466.5	$6.0612	$330,132	18,426.1	$5.9689	$109,983	2,152.8	$6.0520	$13,029	$453,144
4	Schedule 2 - Small Commercial	16,972.2	6.1600	104,549	6,033.6	6.0816	36,694	803.5	6.1464	4,938	146,181
5	Schedule 3 - Large Commercial	16,513.3	5.9160	97,693	3,213.7	5.8783	18,891	351.5	5.9135	2,079	118,663
6	Schedules 1, 2 and 3	87,952.0		532,374	27,673.4		165,568	3,307.8		20,046	717,988
7											
8	Schedule 4 - Seasonal	88.5	5.6610	501	57.8	5.5889	323.0	0.0	0.0000	0	824
9	Schedule 5 - General Firm	5,173.6	5.6612	29,289	952.7	5.5800	5,316	153.5	5.6705	870	35,475
10											
11	Industrial										
12	Interruptible - Schedule 7	101.4	5.6607	574	16.8	5.5952	94	0.0	0.0000	0	668
13	- Schedule 10	0.0	0.0000	0	0.0	0.0000	0	0.0	0.0000	0	0
14	Total Industrials	101.4		574	16.8		94	0.0		0	668
15											
16	N G V Fuel - Stations - Schedule 6	498.7	5.3609	2,673	58.3	5.3059	309	0.0	5.3059	0	2,982
17											
18	Total NGV	498.7		2,673	58.3		309	0.0		0	2,982
19											
20	Total Core and Non-Core Sales	93,814.2		565,411	28,759.0		171,610	3,461.3		20,916	757,937
21											
22	Core and Non-Core Transportation Service										
23	Schedule 22 - Firm Service	217.1	0.0271	6	7,401.5	(0.0060)	(45)	2,260.6	0.0271	62	23
24											
25	- Interruptible Service	14,124.9	0.0271	382	1,118.0	(0.0060)	(7)	138.5	0.0271	4	379
26											
27	Schedule 23 - Large Commercial	2,810.4	0.0271	76	1,005.8	(0.0060)	(6)	0.0	0.0271	0	70
28	Schedule 25 - Firm Service	6,703.6	0.0271	182	3,556.1	(0.0060)	(21)	232.0	0.0271	6	167
29	Schedule 27 - Interruptible Service	5,715.4	0.0271	155	367.2	(0.0060)	(2)	0.0	0.0271	0	153
30	Total Core and Non-Core T-Service	29,571.4		801	13,448.6		(81)	2,631.1		72	792
31											
32											
33	Total Core and Non-Core Sales and										
34	Transportation Service										
35	Cost of Gas Sold	123,385.6		$566,212	42,207.6		$171,529	6,092.4		$20,988	$758,729

Line No.	Particulars	Lower Mainland Energy TJ	Lower Mainland Unit Cost $/GJ	Lower Mainland Cost of Gas ($000)	Inland Including Revelstoke Energy TJ	Inland Including Revelstoke Unit Cost $/GJ	Inland Including Revelstoke Cost of Gas ($000)	Columbia Energy TJ	Columbia Unit Cost $/GJ	Columbia Cost of Gas ($000)	Total Cost of Gas ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	BYPASS AND SPECIAL RATES										
2	Bypass and Special Rates Sales										
3	Schedule 4 - Seasonal	0.0	$0.0000	$0	0.0	$0.0000	$0	0.0	$0.0000	$0	$0
4											
5	Large Industrial										
6	Interruptible - Schedule 10	0.0	0.0000	0	0.0	0.0000	0	0.0	0.0000	0	0
7											
8											
9	Total Large Industrial	0.0		0.0	0.0		0.0	0.0		0.0	0
10	Total Bypass and Spec. Rates Sales	0.0		0.0	0.0		0.0	0.0		0.0	0
11											
12	Bypass and Special Rates Transportation Service										
13	Schedule 22 - Firm Service	0.0	0.0271	0	12,070.4	(0.0060)	(73)	260.0	0.0271	7	(66)
14											
15	- Interruptible Service	0.0	0.0271	0	2,241.9	(0.0060)	(13)	17.0	0.0271	0	(13)
16											
17	- Burrard Thermal - Firm	26,009.3	0.0075	196			0	0.0		0	196
18	Schedule 23 - Large Commercial	0.0	0.0271	0	0.0	(0.0060)	0	0.0	0.0271	0	0
19	Schedule 25 - Firm Service	0.0	0.0271	0	1,406.9	(0.0060)	(8)	0.0	0.0271	0	(8)
20	Schedule 27 - Interruptible Service	0.0	0.0271	0	0.0	(0.0060)	0	0.0	0.0271	0	0
21	Byron Creek	0.0	0.0000	0	0.0	0.0000	0	158.7	0.0271	4	4
22	Centra BC (PCEC)	36,553.3	0.0075	275							275
23	Total Bypass and Spec. Rates T-Svc	62,562.6		471	15,719.2		(94)	435.7		11	388
24											
25											
26	Total Bypass and Special Rates Sales and										
27	Transportation Service										
28	Cost of Gas Sold	62,562.6		471	15,719.2		(94)	435.7		11	388
29											
30	Total Sales and Transportation										
31	Transportation Service										
32	Cost of Gas Sold	185,948.2		$566,683	57,926.8		$171,435	6,528.1		$20,999	$759,117

		Inland Excluding Revelstoke			Revelstoke			Inland Including Revelstoke		
Line No.	Particulars	Energy TJ	Unit Cost $/GJ	Cost of Gas ($000)	Energy TJ	Unit Cost $/GJ	Cost of Gas ($000)	Energy TJ	Unit Cost $/GJ	Cost of Gas ($000)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Core and Non-Core									
2	Core and Non-Core Sales									
3	Schedule 1 - Residential	18,335.3	$5.9555	$109,196	90.8	$8.6690	$787	18,426.1	$5.9689	$109,983
4	Schedule 2 - Small Commercial	5,957.0	6.0483	36,030	76.6	$8.6690	664	6,033.6	6.0816	36,694
5	Schedule 3 - Large Commercial	3,147.0	5.8192	18,313	66.7	$8.6690	578	3,213.7	5.8783	18,891
6	Schedules 1, 2 and 3	27,439.3		163,539	234.1		2,029	27,673.4		165,568
7										
8	Schedule 4 - Seasonal	57.8	5.5889	323	0.0	0.0000	0	57.8	5.5889	323
9	Schedule 5 - General Firm	952.7	5.5800	5,316	0.0	0.0000	0	952.7	5.5800	5,316
10										
11	Large Industrial									
12	Interruptible - Schedule 7	16.8	5.5952	94	0.0	0.0000	0	16.8	5.5952	94
13										
14	- Schedule 10	0.0	0.0000	0	0.0	0.0000	0	0.0	0.0000	0
15	Total Industrials - Captive Sales	16.8		94	0.0		0	16.8		94
16										
17	N G V Fuel - Stations - Schedule 6	58.3	5.3059	309	0.0	0.0000	0	58.3	5.3059	309
18										
19	Total NGV	58.3		309	0.0		0	58.3		309
20	Total Core and Non-Core Sales	28,524.9		169,581	234.1		2,029	28,759.0		171,610
21										
22	Core and Non-Core Transportation Service									
23	Schedule 22 - Firm Service	7,401.5	(0.0060)	(45)	0.0	0.0000	0	7,401.5	(0.0060)	(45)
24										
25	- Interruptible Service	1,118.0	(0.0060)	(7)	0.0	0.0000	0	1,118.0	(0.0060)	(7)
26										
27	Schedule 23 - Large Commercial	1,005.8	(0.0060)	(6)	0.0	0.0000	0	1,005.8	(0.0060)	(6)
28	Schedule 25 - Firm Service	3,556.1	(0.0060)	(21)	0.0	0.0000	0	3,556.1	(0.0060)	(21)
29	Schedule 27 - Interruptible Service	367.2	(0.0060)	(2)	0.0	0.0000	0	367.2	(0.0060)	(2)
30	Total Core and Non-Core T-Service	13,448.6		(81)	0.0		0	13,448.6		(81)
31										
32	Total Core and Non-Core Sales and T-Svc									
33	Cost of Gas Sold	41,973.5		169,500	234.1		2,029	42,207.6		171,529
34										
35	BYPASS AND SPECIAL RATES									
36	Schedule 4 - Seasonal Sales	0.0	0.0000	$0	0.0	0.0000	$0	0.0	0.0000	$0
37	Other Bypass and Special Rates	15,719.2	(0.0060)	(94)	0.0	0.0000	0	15,719.2	(0.0060)	(94)
38	Total Bypass and Special Rates Sales and T-Service									
39	Cost of Gas Sold	15,719.2		(94)	0.0		0	15,719.2		(94)
40										
41	Total Cost of Gas Sold	57,692.7		$169,406	234.1		$2,029	57,926.8		$171,435

BC GAS UTILITY LTD.
OPERATING AND MAINTENANCE ("O&M") EXPENSE
FOR THE YEARS ENDING DECEMBER 31, 2003 TO 2007

- See Section D for a full description of the changes in O & M.

BC GAS UTILITY
OPERATING & MAINTENANCE EXPENSE
FOR THE YEARS 2002 TO 2007
SUMMARY BY BUSINESS UNIT
($000)

Line No.	Particulars	Projected 2002	Forecast 2003	Forecast 2004	Forecast 2005	Forecast 2006	Forecast 2007
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Distribution Operating & Maintenance	$21,010	$22,000	$23,334	$24,394	$24,972	$25,670
2	Emergency Management	5,582	5,792	5,948	6,122	6,301	6,486
3	Account Services / Fieldwork	5,735	6,315	6,501	6,708	10,083	12,406
4	Distribution Support	2,074	2,131	2,189	2,254	2,322	2,391
5	**Total Distribution**	**34,401**	**36,238**	**37,972**	**39,478**	**43,678**	**46,953**
6							
7	Operations Support	1,053	1,082	1,111	1,145	1,179	1,214
8	Engineering	4,961	5,326	5,462	5,614	5,770	5,931
9	Community, Developer and Aboriginal Relations	2,666	2,635	2,685	2,760	2,839	2,919
10	Measurement	3,111	3,488	3,628	3,781	3,937	4,100
11	**Total Network Development & Operations Support**	**11,791**	**12,531**	**12,886**	**13,300**	**13,725**	**14,164**
12							
13	Transmission	10,581	12,093	12,444	12,822	13,207	13,623
14	Gas Supply (excluding Core Market Admin Costs)	1,841	1,953	2,008	2,067	2,129	2,192
15	**Total Gas Supply & Transmission**	**12,422**	**14,046**	**14,452**	**14,889**	**15,336**	**15,815**
16							
17	Customer Care	42,101	47,777	48,661	49,815	50,742	52,160
18	Marketing & Others	10,080	10,118	10,367	10,647	10,934	11,229
19	**Total Marketing & Customer Care**	**52,181**	**57,895**	**59,028**	**60,462**	**61,676**	**63,389**
20							

($000)

Line No.	Particulars	Projected 2002	Forecast 2003	Forecast 2004	Forecast 2005	Forecast 2006	Forecast 2007
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
21	Regulatory	3,584	3,670	3,761	3,862	3,965	4,072
22	Environment, Health & Safety	1,906	1,954	2,003	2,058	2,115	2,173
23	Supply Chain & Logistics	4,036	4,151	4,270	4,402	4,539	4,680
24	Facilities	5,882	5,999	6,231	5,961	6,136	6,315
25	Land Services	451	601	652	670	689	708
26	Legal & Risk Management	3,923	4,967	7,168	7,899	8,644	9,404
27	**Total RESSCL and Legal / Risk Management**	**19,782**	**21,342**	**24,085**	**24,852**	**26,088**	**27,352**
28							
29	CFO & Treasurer	8,585	9,703	9,979	10,286	10,604	10,931
30	Operations Finance	2,519	2,592	2,668	2,752	2,839	2,928
31	**Total Finance**	**11,104**	**12,295**	**12,647**	**13,038**	**13,443**	**13,859**
32							
33	**Information Technology Services**	**13,536**	**14,564**	**15,228**	**15,849**	**16,245**	**16,650**
34							
35	**CEO & President**	**9,316**	**9,380**	**9,552**	**9,846**	**10,045**	**10,251**
36							
37	**Human Resources**	**5,119**	**5,315**	**5,470**	**5,643**	**5,821**	**6,005**
38							
39	**TOTAL GROSS O&M**	**$169,652**	**$183,606**	**$191,320**	**$197,357**	**$206,057**	**$214,438**
40							
41	O&M Reduction		(3,300)	(3,300)	(3,300)	(3,300)	(3,300)
42							
43	**TOTAL GROSS O&M IN RATES**	**$169,652**	**$180,306**	**$188,020**	**$194,057**	**$202,757**	**$211,138**
44							
45	Less:						
46	Capitalized Overhead (Page 2.2)	(25,162)	(25,879)	(27,071)	(17,917)	(18,437)	(19,001)
47	Vehicle Lease	(1,779)	(1,833)	(1,888)	(1,945)	(2,003)	(2,063)
48	Fort Nelson	(571)	(581)	(591)	(603)	(615)	(627)
49							
50	**NET APPLIED-FOR UTILITY O&M**	**$142,140**	**$152,013**	**$158,470**	**$173,592**	**$181,702**	**$189,447**

BC GAS UTILITY LTD.
OPERATING & MAINTENANCE EXPENSE - CALCULATION OF CAPITALIZED OVERHEAD
FOR THE YEARS 2002 TO 2007
($000)

		Current Method			**Study Method**								
					2005			2006			2007		
Line No.	Particulars	2002 Projected	2003 Forecast	2004 Forecast	O&M Forecast	Capitalized Overhead Percent	Capitalized Overhead	O&M Forecast	Capitalized Overhead Percent	Capitalized Overhead	O&M Forecast	Capitalized Overhead Percent	Capitalized Overhead
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
1	**Current Method**												
2	Gross O&M	$169,652	$183,606	$191,320									
3													
4	Less:												
5	O&M Reduction	-	(3,300)	(3,300)									
6	Vehicle Lease	(571)	(581)	(591)									
7	Ft. Nelson	(1,779)	(1,833)	(1,888)									
8	DRIA	(1,624)	(1,652)	(1,681)									
9	OPEB	(5,053)	(6,082)	(6,265)									
10	OPEB cash payment	432	545	561									
11	Capital-related Portion - CustomerWorks	(3,793)	(8,978)	(8,978)									
12	Other	-	17	17									
13	Net O&M for Capitalized Overhead	$157,264	$161,742	$169,195									
14													
15	Capitalized Overhead Percentage	16%	16%	16%									
16													
17	**Study Method**												
18	Distribution				$39,478	25%	9,870	$43,678	23%	$10,117	46,953	22%	$10,404
19	Network Development and Operations Support				13,300	49%	6,517	13,725	49%	6,725	14,164	49%	6,940
20	Gas Supply and Transmission				14,889	0%	-	15,336	0%	-	15,815	0%	-
21	Marketing & Customer Care				60,462	0%	-	61,676	0%	-	63,389	0%	-
22	RESSCL				16,953	10%	1,695	17,444	10%	1,744	17,948	10%	1,795
23	Legal / Risk Management				7,899	0%	-	8,644	0%	-	9,404	0%	-
24	CFO & Treasurer				10,286	0%	-	10,604	0%	-	10,931	0%	-
25	Operations Finance				2,752	5%	138	2,839	5%	142	2,928	5%	146
26	Information Technology Services				15,849	0%	-	16,245	0%	-	16,650	0%	-
27	CEO & President				9,846	0%	-	10,045	0%	-	10,251	0%	-
28	Human Resources				5,643	0%	-	5,821	0%	-	6,005	0%	-
29	Total Gross O&M				$197,357			$206,057			214,438		
30	O&M Reduction				(3,300)		($303)	(3,300)		($291)	(3,300)		($284)
31	Total Gross O&M in Rates				$194,057			$202,757			$211,138		
32													
33	Capitalized Overhead	$25,162	$25,879	$27,071			$17,917			$18,437			$19,001

BC GAS UTILITY LTD.
O&M HISTORICAL COMPARISON
FOR THE YEARS 1997 TO 2007
(Actual O&M Restated to 2002 Organizational Structure)
($000)

Line No.	Particulars	1997	1998	1999	2000	Preliminary 2001	Projected 2002	Forecast 2003	Forecast 2004	Forecast 2005	Forecast 2006	Forecast 2007
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1	Distribution	$39,661	$39,035	$36,821	$35,165	$36,349	$34,401	$36,238	$37,972	$39,478	$43,678	$46,953
2												
3	Network Development and Operations Support	15,020	14,735	14,511	13,480	12,995	11,791	12,531	12,886	13,300	13,725	14,164
4												
5	Gas Supply & Transmission	8,596	8,577	9,960	10,205	11,276	12,422	14,046	14,452	14,889	15,336	15,815
6												
7	Marketing & Customer Care	31,923	35,105	29,844	33,666	36,371	52,181	57,895	59,028	60,462	61,676	63,389
8												
9	RESSCL and Legal / Risk Management	21,777	20,736	19,246	19,551	20,145	19,782	21,342	24,085	24,852	26,088	27,352
10												
11	Finance	8,257	7,746	6,818	9,128	10,882	11,104	12,295	12,647	13,038	13,443	13,859
12												
13	Information Technology Services	13,614	14,600	14,253	14,259	14,671	13,536	14,564	15,228	15,849	16,245	16,650
14												
15	CEO & President	7,667	9,740	7,786	8,671	11,152	9,316	9,380	9,552	9,846	10,045	10,251
16												
17	Human Resources	5,883	5,673	4,778	4,795	4,845	5,119	5,315	5,470	5,643	5,821	6,005
18												
19	**TOTAL GROSS O&M**	**$152,398**	**$155,947**	**$144,017**	**$148,920**	**$158,686**	**$169,652**	**$183,606**	**$191,320**	**$197,357**	**$206,057**	**$214,438**
20												
21	O&M Reduction							(3,300)	(3,300)	(3,300)	(3,300)	(3,300)
22												
23	**TOTAL GROSS O&M IN RATES**	**$152,398**	**$155,947**	**$144,017**	**$148,920**	**$158,686**	**$169,652**	**$180,306**	**$188,020**	**$194,057**	**$202,757**	**$211,138**
24												
25	Less:											
26	Capitalized Overhead	(32,631)	(29,162)	(29,336)	(23,366)	(23,856)	(25,162)	(25,879)	(27,071)	(17,917)	(18,437)	(19,001)
27	Vehicle Lease	(1,262)	(1,415)	(1,101)	(1,737)	(1,851)	(1,779)	(1,833)	(1,888)	(1,945)	(2,003)	(2,063)
28	Fort Nelson	(540)	(549)	(512)	(521)	(571)	(571)	(581)	(591)	(603)	(615)	(627)
29												
30	**NET UTILITY O&M**	**$117,965**	**$124,821**	**$113,068**	**$123,296**	**$132,408**	**$142,140**	**$152,013**	**$158,470**	**$173,592**	**$181,702**	**$189,447**

($000)

Line No.	Particulars	1997	1998	1999	2000	Preliminary 2001	Projected 2002	Forecast 2003	Forecast 2004	Forecast 2005	Forecast 2006	Forecast 2007
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1	M&E Labour	$28,176	$28,823	$27,706	$28,470	$32,822	$30,721	$31,885	$32,968	$33,952	$34,969	$36,018
2	OPEIU Labour	32,049	34,660	26,020	25,970	26,485	22,101	23,178	23,905	24,712	25,544	26,404
3	IBEW Labour	24,776	25,308	22,180	21,065	22,641	20,954	21,685	22,542	23,272	24,026	24,805
4	Other Post Employment Benefits	-	-	-	2,500	4,621	5,053	6,082	6,265	6,468	6,677	6,893
5	Labour adjustment	-	-	(134)	29	-	-	-	-	-	-	-
6	Total Labour	85,001	88,791	75,772	78,034	86,569	78,829	82,830	85,680	88,404	91,216	94,120
7												
8	Vehicle	4,562	4,376	3,772	4,807	4,769	4,683	4,819	4,910	5,013	5,117	5,223
9	Materials, Supplies & Fees	27,919	25,319	23,430	28,054	27,672	23,870	25,552	28,042	29,182	30,241	31,321
10	Services incl. Computer	42,468	39,903	41,247	39,243	41,737	70,019	77,447	79,710	82,266	87,035	91,372
11	Recoveries	(7,552)	(2,442)	(204)	(1,218)	(2,061)	(7,749)	(7,042)	(7,022)	(7,508)	(7,552)	(7,598)
12	Total Non-Labour	67,397	67,156	68,245	70,886	72,117	90,823	100,776	105,640	108,953	114,841	120,318
13												
14	**TOTAL GROSS O&M**	**$152,398**	**$155,947**	**$144,017**	**$148,920**	**$158,686**	**$169,652**	**$183,606**	**$191,320**	**$197,357**	**$206,057**	**$214,438**
15												
16	O&M Reduction	-	-	-	-	-	-	(3,300)	(3,300)	(3,300)	(3,300)	(3,300)
17												
18	**TOTAL GROSS O&M IN RATES**	**$152,398**	**$155,947**	**$144,017**	**$148,920**	**$158,686**	**$169,652**	**$180,306**	**$188,020**	**$194,057**	**$202,757**	**$211,138**
19												
20	Less:											
21	Capitalized Overhead	(32,631)	(29,162)	(29,336)	(23,366)	(23,856)	(25,162)	(25,879)	(27,071)	(17,917)	(18,437)	(19,001)
22	Vehicle Lease	(1,262)	(1,415)	(1,101)	(1,737)	(1,851)	(1,779)	(1,833)	(1,888)	(1,945)	(2,003)	(2,063)
23	Fort Nelson	(540)	(549)	(512)	(521)	(571)	(571)	(581)	(591)	(603)	(615)	(627)
24												
25	**NET UTILITY O&M**	**$117,965**	**$124,821**	**$113,068**	**$123,296**	**$132,408**	**$142,140**	**$152,013**	**$158,470**	**$173,592**	**$181,702**	**$189,447**

BC GAS UTILITY LTD.
EMPLOYEES HISTORICAL COMPARISON
FULL-TIME EQUIVALENT (FTE) EMPLOYEES BASED ON PAID HOURS
FOR THE YEARS 1997 TO 2007

Line No.	Particulars	1997	1998	1999	2000	Preliminary 2001	Projected 2002	Forecast 2003	Forecast 2004	Forecast 2005	Forecast 2006	Forecast 2007
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1	Distribution	861.0	715.1	696.6	675.5	615.3	586.0	600.5	606.5	606.5	606.5	606.5
2												
3	Network Development and Operations Support	181.3	177.9	173.0	170.0	164.9	169.0	172.0	172.5	173.0	173.5	174.0
4												
5	Gas Supply & Transmission	93.1	97.5	104.6	108.1	115.3	118.0	121.5	121.5	121.5	121.5	121.5
6												
7	Marketing & Customer Care	125.0	188.0	161.8	182.4	183.4	70.6	70.6	70.6	70.6	70.6	70.6
8												
9	RESSCL and Legal / Risk Management	193.9	183.5	168.6	163.8	168.8	170.1	170.1	170.1	170.1	170.1	170.1
10												
11	Finance	98.4	81.6	62.5	76.2	74.5	70.2	70.2	70.2	70.2	70.2	70.2
12												
13	Information Technology Services	64.9	65.5	61.4	59.0	56.7	52.4	52.4	52.4	52.4	52.4	52.4
14												
15	CEO & President	14.0	13.0	14.0	15.5	14.1	14.0	14.0	14.0	14.0	14.0	14.0
16												
17	Human Resources	61.7	61.8	52.5	53.4	54.2	52.3	52.3	52.3	52.3	52.3	52.3
18												
19	Total FTE	1,693.3	1,583.9	1,495.0	1,503.9	1,447.2	1,302.6	1,323.6	1,330.1	1,330.6	1,331.1	1,331.6

BC GAS UTILITY LTD.
PROPERTY AND CORPORATE CAPITAL TAXES
FOR THE YEARS ENDING DECEMBER 31, 2003 TO 2007

Property taxes and the B.C. Corporation Capital Tax are taxes levied against the Company by Provincial, Municipal and other local governments.

1. Property Tax Expense

1% in Lieu: The 1% tax in lieu of general municipal taxes is calculated based on the amount of revenues collected within municipal boundaries multiplied by 1% (1.25% for the City of Vancouver). The increase in 1% tax is due primarily to higher revenues. The effect of the 2001 rate increases on 1% in lieu causes revenue requirement increases in 2002 and 2003 due to the lagged payment of these levies to the municipalities.

General, School and Other: Property taxes include general, school and other property taxes as well as Oil and Gas Commission fees. Assessed values for assets other than transmission pipe are estimated using 2002 actuals, a 1-3% market adjustments for land and buildings, and plant additions in mains and services. General mill rates are forecast to increase between 1% to 3% annually and are set separately by each local government taxation authority. The provincial government sets school tax rate and no change is expected in the 2003 – 2007 period. Other property taxes are collected by the local government taxation authorities on behalf of other taxation authorities such as regional districts and hospitals and are expected to increase by 3% annually for the 2003-2007 period.

Beyond normal year-to-year inflation and revenue-driven increases in the 1% tax no additional property tax increases are included although the possibility of such increases in several areas has been identified. BC Gas requests deferral

BC GAS UTILITY LTD.
PROPERTY AND CORPORATE CAPITAL TAXES
FOR THE YEARS ENDING DECEMBER 31, 2003 TO 2007

account treatment for variances in property taxes from forecast as discussed in Section E.

2. B.C. Corporation Capital Tax (CCT)

Corporate Capital Tax Expense:	On July 30, 2001, the Ministry of Finance of the Province of British Columbia announced that it would phase out the corporate capital tax on non-financial institutions over two years. With the planned elimination of the CCT by September 1, 2002, no provision for CCT expense has been made for the 2003-2007 period.

BC GAS UTILITY LTD.

PROPERTY AND SUNDRY TAXES
FOR THE YEARS ENDING DECEMBER 31, 2003 TO 2007
($000)

Line No.	Particulars	B.C.U.C. Account Number	2003 Total Expenses	2003 Revised Revenue, Total Expenses	2004 Total Expenses	2004 Revised Revenue, Total Expenses	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Property Taxes	305-010					
3	1% in Lieu of General Municipal Tax		$15,120	$15,120	$15,120	$15,120	
5	General, School and Other		26,093	26,093	26,093	26,093	
7	Amortization of Property Tax Deferral		0	0	0	0	
9			41,213	41,213	41,213	41,213	
11	B.C. Corporation Capital Tax		0	0	0	0	
13	Total		$41,213	$41,213	$41,213	$41,213	

Line No.	Particulars	B.C.U.C. Account Number	2005 Total Expenses	2005 Revised Revenue, Total Expenses	2006 Total Expenses	2006 Revised Revenue, Total Expenses	2007 Total Expenses	2007 Revised Revenue, Total Expenses	Reference
25	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
28	Property Taxes	305-010							
30	1% in Lieu of General Municipal Tax		$15,120	$15,120	$15,120	$15,120	$15,120	$15,120	
32	General, School and Other		26,093	26,093	26,093	26,093	26,093	26,093	
34	Amortization of Property Tax Deferral		0	0	0	0	0	0	
36			$41,213	$41,213	$41,213	$41,213	$41,213	$41,213	
38	B.C. Corporation Capital Tax		0	0	0	0	0	0	
40	Total		$41,213	$41,213	$41,213	$41,213	$41,213	$41,213	

BC GAS UTILITY LTD.
DEPRECIATION AND AMORTIZATION EXPENSE
FOR THE YEARS ENDING DECEMBER 31, 2003 TO 2007

Depreciation and amortization expense for 2003 is forecast based on actual 2002 opening plant and deferral account balances, and projected 2002 additions or changes to the account balances. BCUC approved depreciation rates and amortization periods are used for all accounts other than where specific changes are requested below.

BC Gas will be seeking for changes in depreciation rates to be implemented in 2004 and changes to the overhead capitalization rates to be implemented in 2005. A full description of the requested changes can be found under Section E, Pages 11 to 16.

BC GAS UTILITY LTD.
DEPRECIATION AND AMORTIZATION EXPENSES
FOR THE YEARS ENDING DECEMBER 31, 2003 TO 2007
($000)

Line No.	Particulars	2003	2004	2005	2006	2007	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Depreciation Provision						
2							
3	Total Depreciation Expense	$81,492	$90,192	$92,586	$95,976	$95,479	
4							
5	Less: Amortization of Contributions in Aid of Construction	(8,587)	(10,519)	(10,860)	(10,598)	(10,521)	
6		72,905	79,673	81,726	85,378	84,958	
7							
8	- Vehicle Costs Charged to Depreciation Expense	0	0	0	0	0	
9							
10		72,905	79,673	81,726	85,378	84,958	
11							
12	Amortization Expense						
13							
14	Amortization of Deferred Charges	($254)	($126)	($595)	$617	$729	
15							
16							
17		(254)	(126)	(595)	617	729	
18							
19	TOTAL	$72,651	$79,547	$81,131	$85,995	$85,687	

BC GAS UTILITY LTD.
OTHER REVENUE
FOR THE YEARS ENDING DECEMBER 31, 2003 TO 2007

The major items within Other Revenue are the Centra Gas (PCEC) agreements, revenue from service work and SCP Third Party Revenues.

1. Centra Gas (PCEC) Wheeling Agreement

The Centra Gas agreement generates approximately $3.9 million revenues annually. This transportation agreement is for fixed amounts and is independent of energy consumption.

2. Late Payment Charges

Historically, revenues from this source have been approximately 0.4% of residential and commercial revenues of the Inland and Columbia service areas. With the repatriation of Lower Mainland customers from B.C. Hydro late payment charges is projected to increase by $3.4 million annually.

3. Revenue from Service Work

This revenue is generated primarily from connections charges and transfer fees. Customer additions are levied a $85 charge per service. As well, account transfers are assessed a $25 fee.

4. SCP Third Party Revenues

Revenues of $7.2 million associated with the firm transport service agreements with PG&E Energy Trading, Canada Corporation and B.C. Hydro for capacity on the Southern Crossing Pipeline (SCP) plus $1.3 million of incremental SCP Third Party revenues arising from gas supply and transportation activities on SCP is forecast for 2003. For years subsequent to 2003, BC Gas has included $1.0 million annually in other revenues. BC Gas requests deferral account treatment for any variations from the level of SCP Third Party revenues reflected in this Application. See Tab 12, Page 2 Line 7.

OTHER REVENUE
FOR THE YEARS ENDING DECEMBER 31, 2003 TO 2007
($000)

Line No.	Particulars	B.C.U.C Account Number	2003	2004	2005	2006	2007	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**Miscellaneous Revenue**							
2								
3	Thermal Agreement		$0	$0	$0	$0	$0	
4								
5	Centra BC (PCEC) Wheeling Charge		3,943	4,041	4,128	4,129	4,130	
6								
7	SCP Third Party Revenue		8,500	8,200	8,200	8,200	8,200	
8								
9			12,443	12,241	12,328	12,329	12,330	
10								
11	**Other Revenue**							
12	Late Payment Charge		4,789	4,838	4,884	4,929	4,975	
13								
14	Revenue from Service Work		4,555	4,529	4,573	4,637	4,682	
15								
16	Appliance Financing		0	0	0	0	0	
17								
18	NGV Tank Rental	(590)	0	0	0	0	0	
19								
20		(575/319/						
21	All Other	329/579)	950	967	986	1,006	1,026	
22								
23			10,294	10,334	10,443	10,572	10,683	
24								
25	Total Other Operating Revenue		$22,737	$22,575	$22,771	$22,901	$23,013	Tab 2, Page 2

BC GAS UTILITY LTD.
INCOME TAXES
FOR THE YEARS ENDING DECEMBER 31, 2003 TO 2007

Income tax expense is comprised of the Federal Large Corporations Tax and income tax accounted for following the taxes payable method.

1. LARGE CORPORATIONS TAX

LCT is calculated based on taxable capital determined pursuant to the applicable sections of the Income Tax Act multiplied by 0.225%. For details, see Tab 13, Pages 6 and 6.1.

The LCT calculated on Tab 13, Pages 6 and 6.1 is reduced by the corporate surtax on Federal income tax expense calculated in accordance with the applicable provisions of the Income Tax Act.

2. INCOME TAX EXPENSE

Income tax expense is determined based on taxable earnings calculated on the basis of revenues and costs in accordance with the applicable provisions of the Income Tax Act, multiplied by the combined provincial and federal income tax rates. For regulatory purposes, income tax expense is calculated following the taxes payable method of accounting for income taxes.

On June 14, 2001, the federal government reduced the corporate income tax rate to 23% effective January 1, 2003. In addition, the Ministry of Finance of the province of British Columbia announced on July 30, 2001 that it would reduce the provincial income tax rate by three percent, from 16.5% to 13.5% effective January 1, 2003. The combined 2003 corporate income tax rate (including the corporate surtax) becomes 37.62%, a decrease of seven percent from 2001. For the 2004-2007 period, the combined corporate income tax rate is forecast to be 35.62%.

BC Gas is requesting deferral account treatment for income tax variances from those embedded in the calculations and expected to occur at the time of the BCUC decision regarding this application.

BC GAS UTILITY LTD.

INCOME TAXES / REVENUE DEFICIENCY
FOR THE YEARS ENDING DECEMBER 31, 2003 TO 2005
($000)

Line No.	Particulars	2003 Present Rates	2003 ----Revised Rates----- Revised Revenue	2003 ----Revised Rates----- Total	2004 2003 Rates	2004 ----Revised Rates----- Revised Revenue	2004 ----Revised Rates----- Total	2005 2004 Rates	2005 ----Revised Rates----- Revised Revenue	2005 ----Revised Rates----- Total	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	CALCULATION OF INCOME TAXES										
2	Earned Return	$170,346	$9,763	$180,109	$173,647	$6,863	$180,510	$168,748	$12,431	$181,179	Tab 2, Pages 2/2.1
3	Deduct - Interest on Debt	(111,633)	(18)	(111,651)	(111,489)	2	(111,487)	(111,574)	(8)	(111,582)	Tab 13, Page 3
4	Add- Non-Tax Ded. Expense (Net)	1,766	0	1,766	1,906	0	1,906	1,450	0	1,450	Tab 13, Page 4
5											
6	Accounting Income After Tax	60,479	9,745	70,224	64,064	6,865	70,929	58,624	12,423	71,047	
7	Add (Deduct) - Timing Differences	(14,219)	0	(14,219)	(8,333)	0	(8,333)	3,135	0	3,135	Tab 13, Page 4
8	Add - Large Corporation Tax	4,273	(171)	4,102	4,164	(117)	4,047	4,088	(211)	3,877	Tab 13, Page 6
9											
10	Taxable Income After Tax	$50,533	$9,574	$60,107	$59,895	$6,748	$66,643	$65,847	$12,212	$78,059	
11											
12											
13	Income Tax Rate (Current Tax)	37.620%	37.620%	37.620%	35.620%	35.620%	35.620%	35.620%	35.620%	35.620%	
14	1 - Current Income Tax Rate	62.380%	62.380%	62.380%	64.380%	64.380%	64.380%	64.380%	64.380%	64.380%	
15											
16	Deferred Income Tax	0	0	0	0	0	0	0	0	0	
17											
18	Taxable Income (L10 : L14)	$81,009	$15,347	$96,356	$93,033	$10,482	$103,515	$102,279	$18,968	$121,247	
19											
20											
21	Income Tax- Current (L18 x L13)	$30,476	$5,773	$36,249	$33,138	$3,734	$36,872	$36,432	$6,756	$43,188	
22											
23	- Large Corporation Tax	4,273	(171)	4,102	4,164	(117)	4,047	4,088	(211)	3,877	Tab 13, Page 6
24											
25	Total	$34,749	$5,602	$40,351	$37,302	$3,617	$40,919	$40,520	$6,545	$47,065	Tab 2, Pages 2/2.1
26											
27	REVENUE DEFICIENCY										
28	Earned Return		$9,763	$180,109		$6,863	$180,510		$12,431	$181,179	
29	Add - Income Taxes		5,602	40,351		3,617	40,919		6,545	47,065	
30	Deduct - Utility Income Before Taxes,										
31	Present Rates		0	(205,095)		0	(210,949)		0	(209,268)	Tab 2, Pages 2/2.1
32	Corporate Capital Tax		0	0		0	0		0	0	
33											
34	Deficiency After Corporate Capital Tax		$15,365	$15,365		$10,480	$10,480		$18,976	$18,976	

BC GAS UTILITY LTD.

INCOME TAXES / REVENUE DEFICIENCY
FOR THE YEARS ENDING DECEMBER 31, 2006 AND 2007
($000)

Line No.	Particulars	2006 2005 Rates	2006 Revised Rates Revised Revenue	2006 Revised Rates Total	2007 2006 Rates	2007 Revised Rates Revised Revenue	2007 Revised Rates Total	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	CALCULATION OF INCOME TAXES							
2	Earned Return	$175,994	$9,109	$185,103	$185,344	$5,978	$191,322	- Tab 2, Page 2.2
3	Deduct - Interest on Debt	(114,530)	(13)	(114,543)	(118,314)	(9)	(118,323)	- Tab 13, Page 3
4	Add- Non-Tax Ded. Expense (Net)	1,317	0	1,317	1,443	0	1,443	- Tab 13, Page 4
5								
6	Accounting Income After Tax	62,781	9,096	71,877	68,473	5,969	74,442	
7	Add (Deduct) - Timing Differences	5,166	0	5,166	3,648	0	3,648	- Tab 13, Page 4
8	Add - Large Corporation Tax	4,054	102	4,156	4,156	(102)	4,054	- Tab 13, Page 6.1
9								
10	Taxable Income After Tax	$72,001	$9,198	$81,199	$76,277	$5,867	$82,144	
11								
12								
13	Income Tax Rate (Current Tax)	35.620%	35.620%	35.620%	35.620%	35.620%	35.620%	
14	1 - Current Income Tax Rate	64.380%	64.380%	64.380%	64.380%	64.380%	64.380%	
15	Taxable Income Before Income Tax							
16	Deferred Income Tax	0	0	0	0	0	0	
17								
18	Taxable Income (L10 : L14)	$111,837	$14,288	$126,125	$118,480	$9,112	$127,592	
19								
20								
21	Income Tax- Current (L18 x L13)	$39,836	$5,090	$44,926	$42,203	$3,245	$45,448	
22	- Deferred Income Tax							
23	- Large Corporation Tax	4,054	(159)	3,895	4,156	(102)	4,054	- Tab 13, Page 6.1
24								
25	Total	$43,890	$4,931	$48,821	$46,359	$3,143	$49,502	- Tab 2, Page 2.2
26								
27	REVENUE DEFICIENCY							
28	Earned Return		$9,109	$185,103		$5,978	$191,322	
29	Add - Income Taxes		4,931	48,821		3,143	49,502	
30	Deduct - Utility Income Before Taxes,							
31	Present Rates		0	(219,884)		0	(231,703)	- Tab 2, Page 2.2
32	Corporate Capital Tax		0	0		0	0	
33								
34	Deficiency After Corporate Capital Tax		$14,040	$14,040		$9,121	$9,121	

INTEREST EXPENSE FOR UTILITY OPERATIONS
FOR THE YEARS ENDING DECEMBER 31, 2003 TO 2007
($000)

Line No.	Particulars	2003	2004	2005	2006	2007	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	PRESENT RATES						
2	Utility Rate Base	$2,272,203	$2,290,757	$2,309,500	$2,341,590	$2,421,786	- Tab 2, Pages 1, 1.1 & 1.2
3	Weighted average embedded cost of debt in the capital structure						
4	Long-term debt	4.519%	4.43%	4.38%	4.54%	4.54%	- Tab 14, Pages 2 & 2.1
5	Unfunded debt	0.394%	0.44%	0.45%	0.35%	0.35%	- Tab 14, Pages 2 & 2.1
6		4.913%	4.867%	4.831%	4.891%	4.885%	
7	Interest expense for income taxes related to utility operations (rate base x weighted average embedded cost of debt)	$111,633	$111,489	$111,574	$114,530	$118,314	
8	REVISED RATES						
9	Utility Rate Base	$2,272,570	$2,290,732	$2,309,778	$2,341,887	$2,422,100	- Tab 2, Pages 1, 1.1 & 1.2
10	Weighted average embedded cost of debt in the capital structure						
11	Long-term debt	4.519%	4.43%	4.38%	4.54%	4.53%	- Tab 14, Pages 2 & 2.1
12	Unfunded debt	0.394%	0.439%	0.448%	0.353%	0.351%	- Tab 14, Pages 2 & 2.1
13		4.913%	4.867%	4.831%	4.891%	4.885%	
14	Interest expense for income taxes related to utility operations (rate base x weighted average embedded cost of debt	$111,651	$111,487	$111,582	$114,543	$118,323	

BC GAS UTILITY LTD.
NON-TAX DEDUCTIBLE EXPENSES (NET) AND TIMING DIFFERENCE ADJUSTMENTS
FOR THE YEARS ENDING DECEMBER 31, 2003 TO 2007
($000)

Line No.	Particulars	2003	2004	2005	2006	2007	Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	ITEMS OF A PERMANENT NATURE INCREASING TAXABLE INCOME						
2							
3	Amortization of Deferred Charges	($254)	($126)	($595)	$617	$729	
4							
5	Less: Deferred Interest Amortization	1,359	1,359	1,359	0	0	
6							
7							
8							
9							
10							
11	Non-tax Deductible Expenses	661	673	686	700	714	
12							
13							
14							
15	Total Permanent Differences	$1,766	$1,906	$1,450	$1,317	$1,443	
16							
17	TIMING DIFFERENCE ADJUSTMENTS						
18							
19	Depreciation	$72,905	$79,673	$81,726	$85,378	$84,958	- Tab 11, Page
20	Less - Vehicle Costs Charged to Depreciation Expense	0	0	0	0	0	
21	Amortization of Debt Issue Expenses	1,446	1,363	1,262	1,133	1,177	
22	Debt Issue Costs	(1,772)	(1,681)	(1,856)	(2,035)	(2,135)	
23	Capital Cost Allowance	(77,760)	(78,201)	(78,291)	(79,986)	(81,720)	- Tab 13, Page
24	Cumulative Eligible Capital Allowance	(1,131)	(1,134)	(1,082)	(1,020)	(962)	
25	Add Back Principle Portion of Coastal Facilities Lease Payments	1,063	1,063	1,063	1,063	1,595	
26	Short Term Debt Issue Costs	735	735	735	735	735	
27	Reduction in CCA from Reassessment of Customer Advances	0	0	0	0	0	
28	Overheads Capitalized Expensed for Tax Purposes	(9,705)	(10,151)	(422)	(102)	0	
29							
30	Total Timing Differences	($14,219)	($8,333)	$3,135	$5,166	$3,648	

($000)

Class	CCA Rate %	12/31/2002 UCC Balance	2003 Net Additions	2003 CCA	12/31/2003 UCC Balance	2004 Net Additions	2004 CCA	12/31/2004 UCC Balance	2005 Net Additions	2005 CCA	12/31/2005 UCC Balance
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1	4%	$1,225,790	$88,820	($50,808)	$1,263,802	$80,258	($52,157)	$1,291,903	$95,448	($53,585)	$1,333,766
2	6%	253,147	0	(15,189)	237,958	0	(14,277)	223,681	0	(13,421)	210,260
3	5%	4,047	0	(202)	3,845	0	(192)	3,653	0	(183)	3,470
6	10%	430	0	(43)	387	0	(39)	348	0	(35)	313
8	20%	23,115	4,134	(5,036)	22,213	4,355	(4,878)	21,690	4,422	(4,780)	21,332
9	25%	4	0	(1)	3	0	(1)	2	0	(1)	1
10	30%	14,844	7,393	(5,562)	16,675	4,991	(5,751)	15,915	4,125	(5,393)	14,647
12	100%	0	0	0	0	0	0	0	0	0	0
13		8,357	0	(884)	7,473	0	(874)	6,599	0	(864)	5,735
14		12	0	(2)	10	0	(2)	8	0	(2)	6
17	8%	401	0	(32)	369	0	(30)	339	0	(27)	312
29	100%	0	0	0	0	0	0	0	0	0	0
38	30%	0	0	0	0	0	0	0	0	0	0
39	25%	2	0	(1)	1	0	0	1	0	0	1
	Total	$1,530,149	$100,347	($77,760)	$1,552,736	$89,604	($78,201)	$1,564,139	$103,995	($78,291)	$1,589,843

Class	CCA Rate %	Jan.1, 2006 UCC Balance	2006 Net Additions	2006 CCA	Jan.1, 2007 UCC Balance	2007 Net Additions	2007 CCA	Dec. 31, 2007 UCC Balance
(1)	(2)	(13)	(14)	(15)	(16)	(17)	(18)	(19)
1	4%	1,333,766	144,720	(56,245)	1,422,241	72,459	(58,339)	1,436,361
2	6%	210,260	0	(12,616)	197,644	0	(11,859)	185,785
3	5%	3,470	0	(174)	3,296	0	(165)	3,131
6	10%	313	0	(31)	282	0	(28)	254
8	20%	21,332	4,305	(4,697)	20,940	4,734	(4,661)	21,013
9	25%	1	0	0	1	0	0	1
10	30%	14,647	6,327	(5,343)	15,631	7,561	(5,823)	17,369
12	100%	0	0	0	0	0	0	0
13		5,735	0	(853)	4,882	0	(820)	4,062
14		6	0	(2)	4	0	(2)	2
17	8%	312	0	(25)	287	0	(23)	264
29	100%	0	0	0	0	0	0	0
38	30%	0	0	0	0	0	0	0
39	25%	1	0	0	1	0	0	1
	Total	$1,589,843	$155,352	($79,986)	$1,665,209	$84,754	($81,720)	$1,668,243

BC GAS UTILITY LTD.

CALCULATION OF LARGE CORPORATION TAX
FOR THE YEARS ENDING DECEMBER 31, 2003 TO 2005
($000)

Line No.	Particulars	Reference	2003 Present Rates	2003 Revised Rates	2004 2003 Rates	2004 Revised Rates	2005 2004 Rates	2005 Revised Rates
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Large Corporation Tax							
2								
3	Utility Capital (Line 26)		$2,293,928	$2,294,295	$2,305,410	$2,305,385	$2,317,865	$2,318,143
4	Add: Security Deposits		2,611	2,611	2,687	2,687	2,770	2,770
5	Long Term Construction Advances		700	700	700	700	700	700
6	Deferred Income Tax		364	364	364	364	364	364
7	Work in Progress Attracting AFUDC		14,000	14,000	14,000	14,000	14,000	14,000
8	Sub-total		2,311,603	2,311,970	2,323,161	2,323,136	2,335,699	2,335,977
9								
10	Utility Portion of $10,000,000 Deduction							
11	(Line 38 x $10,000,000)		(9,446)	(9,446)	(9,464)	(9,464)	(9,483)	(9,483)
12								
13	Taxable Capital		$2,302,157	$2,302,524	$2,313,697	$2,313,672	$2,326,216	$2,326,494
14								
15	Large Corporation Tax Rate		0.225%	0.225%	0.225%	0.225%	0.225%	0.225%
16								
17	Large Corporation Tax		$5,180	$5,181	$5,206	$5,206	$5,234	$5,235
18	Less: Surtax	1.12%	(907)	(1,079)	(1,042)	(1,159)	(1,146)	(1,358)
19								
20	Large Corporation Tax		$4,273	$4,102	$4,164	$4,047	$4,088	$3,877
21								
22								
23	Net Plant in Service, Ending	Tab 2, Pg 1, 1.1	$2,174,512	$2,174,512	$2,209,230	$2,209,230	$2,231,403	$2,231,403
24	All Other Rate Base Items - Lines 25 - 30 of	Tab 2, Pg 1, 1.1	119,416	119,783	96,180	96,155	86,462	86,740
25								
26	Utility Capital		2,293,928	2,294,295	2,305,410	2,305,385	2,317,865	2,318,143
27								
28	Non-Rate Base Items							
29	Net Book Value of Lower Mainland Premium		121,008	121,008	116,708	116,708	112,408	112,408
30	Disallowed Plant Costs		2,444	2,444	2,344	2,344	2,244	2,244
31	Plant Held for Future Use		0	0	0	0	0	0
32	Fort Nelson Division		4,800	4,800	4,900	4,900	5,000	5,000
33	Squamish Gas Co. Ltd.		6,400	6,400	6,550	6,550	6,700	6,700
34								
35	Total Capital		$2,428,580	$2,428,947	$2,435,912	$2,435,887	$2,444,217	$2,444,495
36								
37								
38	Proportion of Utility Capital to Total Capital		94.46%	94.46%	94.64%	94.64%	94.83%	94.83%

CALCULATION OF LARGE CORPORATION TAX
FOR THE YEARS ENDING DECEMBER 31, 2006 AND 2007
($000)

Line No.	Particulars	Reference	2006 2005 Rates	2006 Revised Rates	2007 2006 Rates	2007 Revised Rates
	(1)	(2)	(3)	(4)	(5)	(6)
1	Large Corporation Tax					
2						
3	Utility Capital (Line 26)		$2,350,301	$2,350,598	$2,428,218	$2,428,532
4	Add: Security Deposits		2,857	2,857	2,946	2,946
5	Long Term Construction Advances		700	700	700	700
6	Deferred Income Tax		364	364	364	364
7	Work in Progress Attracting AFUDC		14,000	14,000	14,000	14,000
8	Sub-total		2,368,222	2,368,519	2,446,228	2,446,542
9						
10	Utility Portion of $10,000,000 Deduction					
11	(Line 38 x $10,000,000)		(9,506)	(9,506)	(9,536)	(9,537)
12						
13	Taxable Capital		$2,358,716	$2,359,013	$2,436,692	$2,437,005
14						
15	Large Corporation Tax Rate		0.225%	0.225%	0.225%	0.225%
16						
17	Large Corporation Tax		$5,307	$5,308	$5,483	$5,483
18	Less: Surtax	1.12%	(1,253)	(1,413)	(1,327)	(1,429)
19						
20	Large Corporation Tax		$4,054	$3,895	$4,156	$4,054
21						
22						
23	Net Plant in Service, Ending	Tab 2, Page 1.2	$2,268,197	$2,268,197	$2,346,724	$2,346,724
24	All Other Rate Base Items - Lines 25 - 30 of	Tab 2, Page 1.2	82,104	82,401	81,494	81,808
25						
26	Utility Capital		2,350,301	2,350,598	2,428,218	2,428,532
27						
28	Non-Rate Base Items					
29	Net Book Value of Lower Mainland Premium		108,108	108,108	103,808	103,808
30	Disallowed Plant Costs		2,144	2,144	2,044	2,044
31	Plant Held for Future Use		0	0	0	0
32	Fort Nelson Division		5,100	5,100	5,200	5,200
33	Squamish Gas Co. Ltd.		6,850	6,850	7,000	6,850
34						
35	Total Capital		$2,472,503	$2,472,800	$2,546,270	$2,546,434
36						
37						
38	Proportion of Utility Capital to Total Capital		95.06%	95.06%	95.36%	95.37%

BC GAS UTILITY LTD.
RETURN ON CAPITAL
FOR THE YEARS ENDING DECEMBER 31, 2003 TO 2007

Long-Term Debt

A $150 million long-term debt issue with a coupon rate of 5.5% is planned for March 31, 2003. For the 2004 to 2007 period, long-term debt issues planned are $100 million, $250 million, $150 million and $150 million respectively, all with a 7% coupon rate.

Unfunded Debt

The unfunded debt rate used in this Application is forecast at 5% for the years 2003 to 2007.

Common Equity

The calculations in this Application have made use of the currently approved ROE of 9.13% allowed for 2002. The 2003 rates applied for in this Application will be adjusted for any changes arising from the Commission ROE automatic adjustment mechanism, which will be determined by the Commission in December 2002 for the 2003 allowed ROE.

BC GAS UTILITY LTD.
RETURN ON CAPITAL
FOR THE YEARS ENDING DECEMBER 31, 2003 TO 2005
($000)

Line No.	Particulars	-------- Capitalization -------- Reference	Amount		%	Average Embedded Cost	Cost Component	Earned Return
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2003 PRESENT RATES							
2	Long-Term Debt	Tab 14, Page 3		$1,343,432	59.12%	7.643%	4.519%	
3	Unfunded Debt			178,944	7.88%	5.000%	0.394%	
4	Preference Shares			0	0.00%	0.000%	0.000%	
5	Common Equity			749,827	33.00%	7.830%	2.584%	
6								
7				$2,272,203	100.00%		7.497%	
8								
9	2003 REVISED RATES							
10	Long-Term Debt			$1,343,432	59.12%	7.643%	4.519%	$102,679
11	Unfunded Debt		$178,944					
12	Adjustment, Revised Rates		246	179,190	7.88%	5.000%	0.394%	8,960
13	Preference Shares			0	0.00%	0.000%	0.000%	0
14	Common Equity			749,948	33.00%	9.130%	3.013%	68,470
15								
16				$2,272,570	100.00%		7.926%	$180,109
17								
18	2004 AT 2003 RATES							
19	Long-Term Debt	Tab 14, Page 3.1		$1,333,811	58.23%	7.605%	4.428%	
20	Unfunded Debt			200,996	8.77%	5.000%	0.439%	
21	Preference Shares			0	0.00%	0.000%	0.000%	
22	Common Equity			755,950	33.00%	8.221%	2.713%	
23								
24				$2,290,757	100.00%		7.580%	
25								
26	2004 REVISED RATES							
27	Long-Term Debt			$1,333,811	58.23%	7.605%	4.428%	$101,436
28	Unfunded Debt		$200,996					
29	Adjustment, Revised Rates		(17)	200,979	8.77%	5.000%	0.439%	10,049
30	Preference Shares			0	0.00%	0.000%	0.000%	0
31	Common Equity			755,942	33.00%	9.130%	3.013%	69,018
32								
33				$2,290,732	100.00%		7.880%	$180,503
34								
35	2005 AT 2004 RATES							
36	Long-Term Debt	Tab 14, Page 3.2		$1,340,937	58.06%	7.551%	4.384%	
37	Unfunded Debt			206,428	8.94%	5.000%	0.447%	
38	Preference Shares			0	0.00%	0.000%	0.000%	
39	Common Equity			762,135	33.00%	7.512%	2.479%	
40								
41				$2,309,500	100.00%		7.310%	
42	2005 REVISED RATES							
43	Long-Term Debt			$1,340,937	58.05%	7.551%	4.383%	$101,254
44	Unfunded Debt		$206,428					
45	Adjustment, Revised Rates		186	206,614	8.95%	5.000%	0.448%	10,331
46	Preference Shares			0	0.00%	0.000%	0.000%	0
47	Common Equity			762,227	33.00%	9.130%	3.013%	69,591
48								
49				$2,309,778	100.00%		7.844%	$181,176

BC GAS UTILITY LTD.
RETURN ON CAPITAL
FOR THE YEARS ENDING DECEMBER 31, 2006 AND 2007
($000)

Line No.	Particulars	-------- Capitalization -------- Reference	Amount		%	Average Embedded Cost	Cost Component	Earned Return
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2006 AT 2005 RATES							
2	Long-Term Debt	Tab 14, Page 3.3		$1,403,665	59.94%	7.571%	4.538%	
3	Unfunded Debt			165,200	7.06%	5.000%	0.353%	
4	Preference Shares			0	0.00%	0.000%	0.000%	
5	Common Equity			772,725	33.00%	7.967%	2.629%	
6								
7				$2,341,590	100.00%		7.520%	
8								
9	2006 REVISED RATES							
10	Long-Term Debt			$1,403,665	59.94%	7.571%	4.538%	$106,271
11	Unfunded Debt		$165,200					
12	Adjustment, Revised Rates		199	165,399	7.06%	5.000%	0.353%	8,270
13	Preference Shares			0	0.00%	0.000%	0.000%	0
14	Common Equity			772,823	33.00%	9.130%	3.013%	70,559
15								
16				$2,341,887	100.00%		7.904%	$185,100
17								
18	2007 AT 2006 RATES							
19	Long-Term Debt	Tab 14, Page 3.4		$1,452,962	60.00%	7.559%	4.535%	
20	Unfunded Debt			169,635	7.00%	5.000%	0.350%	
21	Preference Shares			0	0.00%	0.000%	0.000%	
22	Common Equity			799,189	33.00%	8.379%	2.765%	
23								
24				$2,421,786	100.00%		7.650%	
25								
26	2007 REVISED RATES							
27	Long-Term Debt			$1,452,962	59.99%	7.559%	4.535%	$109,829
28	Unfunded Debt		$169,635					
29	Adjustment, Revised Rates		210	169,845	7.01%	5.000%	0.351%	8,492
30	Preference Shares			0	0.00%	0.000%	0.000%	0
31	Common Equity			799,293	33.00%	9.130%	3.013%	72,975
32								
33				$2,422,100	100.00%		7.899%	$191,296

BC GAS UTILITY LTD.

EMBEDDED COST OF LONG-TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2003
($000)

Line No.	Particulars	Issue Date	Maturity Date	Coupon Rate	Principal Amount of Issue	Issue Expense	Net Proceeds of Issue	Effective Interest Cost	Average Principal Outstanding	Annual Cost	Average Embedded Cost
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Series A Purchase Money Mortgage	12-03-1990	09-30-2015	11.800%	$58,943	$855	$58,088	12.054%	$58,943	$7,105	
2	Series B Purchase Money Mortgage	11-30-1991	11-30-2016	10.300%	157,274	2,228	155,046	10.461%	157,274	16,452	
3											
4	2002 Long-Term Debt Issue	09-30-2002	09-30-2012	0.000%	0	0	0	0.000%	0	0	
5	2003 Long-Term Debt Issue	03-31-2003	03-31-2013	5.500%	150,000	1,500	148,500	5.632%	113,014	6,365	
6	2004 Long-Term Debt Issue	09-30-2004	09-30-2014	7.000%	100,000	1,000	99,000	7.142%	0	0	
7	2005 Long-Term Debt Issue	09-30-2005	09-30-2015	7.000%	250,000	2,500	247,500	7.142%	0	0	
8	2006 Long-Term Debt Issue	09-30-2006	09-30-2016	7.000%	150,000	1,500	148,500	7.142%	0	0	
9	2007 Long-Term Debt Issue	09-30-2007	09-30-2017	7.000%	150,000	1,500	148,500	7.142%	0	0	
10											
11	Series F Debentures	08-26-1992	08-26-2002	8.500%	83,980	984	82,996	8.678%	0	0	
12	Series H Debentures	07-28-1993	07-28-2003	8.150%	50,000	507	49,493	8.301%	28,630	2,377	
13											
14	Medium Term Note - Series 6	02-09-1995	02-09-2005	9.800%	20,000	380	19,620	10.106%	20,000	2,021	
15	Medium Term Note - Series 6	03-15-1995	02-09-2005	9.800%	20,000	(387)	20,387	9.494%	20,000	1,899	
16	Medium Term Note - Series 7	06-29-1995	06-29-2005	8.250%	5,000	100	4,900	8.550%	5,000	428	
17											
18	Medium Term Note - Series 9	10-21-1997	06-02-2008	6.200%	55,000	454	54,546	6.308%	55,000	3,469	
19	Med.Term Note - Series 9 (Re-opened)	11-19-1998	06-02-2008	6.200%	58,000	(681)	58,681	6.036%	58,000	3,501	
20	Med.Term Note - Series 9 (Re-opening)	09-21-1999	06-02-2008	6.200%	75,000	2,053	72,947	6.578%	75,000	4,933	
21	Medium Term Note - Series 11	09-21-1999	09-21-2029	6.950%	150,000	2,137	147,863	7.065%	150,000	10,597	
22											
23	Medium Term Note - Series 12	07-20-2000	07-20-2005	6.500%	200,000	2,622	197,378	6.814%	200,000	13,628	
24	Medium Term Note - Series 13	10-16-2000	10-16-2007	6.500%	100,000	728	99,272	6.632%	100,000	6,632	
25	Medium Term Note - Series 14	10-23-2000	10-23-2003	6.000%	50,000	428	49,572	6.317%	40,548	2,562	
26	Medium Term Note - Series 15	12-11-2000	12-11-2002	6.000%	75,000	229	74,771	6.177%	0	0	
27	Medium Term Note - Series 16	07-30-2001	07-31-2006	6.150%	100,000	721	99,279	6.320%	100,000	6,320	
28	LILO Obligations - Kelowna							6.969%	31,904	2,223	
29	LILO Obligations - Prince George, Vernon & Nelson							7.250%	52,829	3,830	
30									$1,266,142	$94,342	
31	Debentures										
32	Series D	12-17-1986	12-17-2006	9.750%	20,000	244	19,756	9.945%	20,000	1,989	
33	Series E	06-08-1989	06-07-2009	10.750%	59,890	637	59,253	10.927%	59,890	6,544	
34									79,890	8,533	
35											
36	Sub-Total								1,346,032	102,875	
37	Less - Fort Nelson Service Area Portion of Long Term Debt								(2,600)	(199)	
38	**Total**								$1,343,432	$102,676	7.643%

BC GAS UTILITY LTD.

EMBEDDED COST OF LONG-TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2004
($000)

Line No.	Particulars	Issue Date	Maturity Date	Coupon Rate	Principal Amount of Issue	Issue Expense	Net Proceeds of Issue	Effective Interest Cost	Average Principal Outstanding	Annual Cost	Average Embedded Cost
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Series A Purchase Money Mortgage	12-03-1990	09-30-2015	11.800%	$58,943	$855	$58,088	12.054%	$58,943	$7,105	
2	Series B Purchase Money Mortgage	11-30-1991	11-30-2016	10.300%	157,274	2,228	155,046	10.461%	157,274	16,452	
3											
4	2002 Long-Term Debt Issue	09-30-2002	09-30-2012	0.000%	0	0	0	0.000%	0	0	
5	2003 Long-Term Debt Issue	03-31-2003	03-31-2013	5.500%	150,000	1,500	148,500	5.632%	150,000	8,448	
6	2004 Long-Term Debt Issue	09-30-2004	09-30-2014	7.000%	100,000	1,000	99,000	7.142%	25,137	1,795	
7	2005 Long-Term Debt Issue	09-30-2005	09-30-2015	7.000%	250,000	2,500	247,500	7.142%	0	0	
8	2006 Long-Term Debt Issue	09-30-2006	09-30-2016	7.000%	150,000	1,500	148,500	7.142%	0	0	
9	2007 Long-Term Debt Issue	09-30-2007	09-30-2017	7.000%	150,000	1,500	148,500	7.142%	0	0	
10											
11	Series F Debentures	08-26-1992	08-26-2002	8.500%	83,980	984	82,996	8.678%	0	0	
12	Series H Debentures	07-28-1993	07-28-2003	8.150%	50,000	507	49,493	8.301%	0	0	
13											
14	Medium Term Note - Series 6	02-09-1995	02-09-2005	9.800%	20,000	380	19,620	10.106%	20,000	2,021	
15	Medium Term Note - Series 6	03-15-1995	02-09-2005	9.800%	20,000	(387)	20,387	9.494%	20,000	1,899	
16	Medium Term Note - Series 7	06-29-1995	06-29-2005	8.250%	5,000	100	4,900	8.550%	5,000	428	
17											
18	Medium Term Note - Series 9	10-21-1997	06-02-2008	6.200%	55,000	454	54,546	6.308%	55,000	3,469	
19	Med.Term Note - Series 9 (Re-opened)	11-19-1998	06-02-2008	6.200%	58,000	(681)	58,681	6.036%	58,000	3,501	
20	Med.Term Note - Series 9 (Re-opening)	09-21-1999	06-02-2008	6.200%	75,000	2,053	72,947	6.578%	75,000	4,933	
21	Medium Term Note - Series 11	09-21-1999	09-21-2029	6.950%	150,000	2,137	147,863	7.065%	150,000	10,597	
22											
23	Medium Term Note - Series 12	07-20-2000	07-20-2005	6.500%	200,000	2,622	197,378	6.814%	200,000	13,628	
24	Medium Term Note - Series 13	10-16-2000	10-16-2007	6.500%	100,000	728	99,272	6.632%	100,000	6,632	
25	Medium Term Note - Series 14	10-23-2000	10-23-2003	6.000%	50,000	428	49,572	6.317%	0	0	
26	Medium Term Note - Series 15	12-11-2000	12-11-2002	6.000%	75,000	229	74,771	6.177%	0	0	
27	Medium Term Note - Series 16	07-30-2001	07-31-2006	6.150%	100,000	721	99,279	6.320%	100,000	6,320	
28	LILO Obligations - Kelowna							6.969%	30,947	2,157	
29	LILO Obligations - Prince George, Vernon & Nelson							7.250%	51,320	3,721	
30									$1,256,621	$93,106	
31	Debentures										
32	Series D	12-17-1986	12-17-2006	9.750%	20,000	244	19,756	9.945%	20,000	1,989	
33	Series E	06-08-1989	06-07-2009	10.750%	59,890	637	59,253	10.927%	59,890	6,544	
34									79,890	8,533	
35											
36	Sub-Total								1,336,511	101,639	
37	Less - Fort Nelson Division Portion of Long Term Debt								(2,700)	(205)	
38	Total								$1,333,811	$101,434	7.605%

BC GAS UTILITY LTD.

EMBEDDED COST OF LONG-TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2005
($000)

Line No.	Particulars	Issue Date	Maturity Date	Coupon Rate	Principal Amount of Issue	Issue Expense	Net Proceeds of Issue	Effective Interest Cost	Average Principal Outstanding	Annual Cost	Average Embedded Cost
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Series A Purchase Money Mortgage	12-03-1990	09-30-2015	11.800%	$58,943	$855	$58,088	12.054%	$58,943	$7,105	
2	Series B Purchase Money Mortgage	11-30-1991	11-30-2016	10.300%	157,274	2,228	155,046	10.461%	157,274	16,452	
3											
4	2002 Long-Term Debt Issue	09-30-2002	09-30-2012	0.000%	0	0	0	0.000%	0	0	
5	2003 Long-Term Debt Issue	03-31-2003	03-31-2013	5.500%	150,000	1,500	148,500	5.632%	150,000	8,448	
6	2004 Long-Term Debt Issue	09-30-2004	09-30-2014	7.000%	100,000	1,000	99,000	7.142%	100,000	7,142	
7	2005 Long-Term Debt Issue	09-30-2005	09-30-2015	7.000%	250,000	2,500	247,500	7.142%	62,842	4,488	
8	2006 Long-Term Debt Issue	09-30-2006	09-30-2016	7.000%	150,000	1,500	148,500	7.142%	0	0	
9	2007 Long-Term Debt Issue	09-30-2007	09-30-2017	7.000%	150,000	1,500	148,500	7.142%	0	0	
10											
11	Series F Debentures	08-26-1992	08-26-2002	8.500%	83,980	984	82,996	8.678%	0	0	
12	Series H Debentures	07-28-1993	07-28-2003	8.150%	50,000	507	49,493	8.301%	0	0	
13											
14	Medium Term Note - Series 6	02-09-1995	02-09-2005	9.800%	20,000	380	19,620	10.106%	2,192	222	
15	Medium Term Note - Series 6	03-15-1995	02-09-2005	9.800%	20,000	(387)	20,387	9.494%	2,192	208	
16	Medium Term Note - Series 7	06-29-1995	06-29-2005	8.250%	5,000	100	4,900	8.550%	2,466	211	
17											
18	Medium Term Note - Series 9	10-21-1997	06-02-2008	6.200%	55,000	454	54,546	6.308%	55,000	3,469	
19	Med.Term Note - Series 9 (Re-opened)	11-19-1998	06-02-2008	6.200%	58,000	(681)	58,681	6.036%	58,000	3,501	
20	Med.Term Note - Series 9 (Re-opening)	09-21-1999	06-02-2008	6.200%	75,000	2,053	72,947	6.578%	75,000	4,933	
21	Medium Term Note - Series 11	09-21-1999	09-21-2029	6.950%	150,000	2,137	147,863	7.065%	150,000	10,597	
22											
23	Medium Term Note - Series 12	07-20-2000	07-20-2005	6.500%	200,000	2,622	197,378	6.814%	110,137	7,505	
24	Medium Term Note - Series 13	10-16-2000	10-16-2007	6.500%	100,000	728	99,272	6.632%	100,000	6,632	
25	Medium Term Note - Series 14	10-23-2000	10-23-2003	6.000%	50,000	428	49,572	6.317%	0	0	
26	Medium Term Note - Series 15	12-11-2000	12-11-2002	6.000%	75,000	229	74,771	6.177%	0	0	
27	Medium Term Note - Series 16	07-30-2001	07-31-2006	6.150%	100,000	721	99,279	6.320%	100,000	6,320	
28	LILO Obligations - Kelowna							6.969%	29,990	2,090	
29	LILO Obligations - Prince George, Vernon & Nelson							7.250%	49,811	3,611	
30									$1,263,847	$92,934	
31	Debentures										
32	Series D	12-17-1986	12-17-2006	9.750%	20,000	244	19,756	9.945%	20,000	1,989	
33	Series E	06-08-1989	06-07-2009	10.750%	59,890	637	59,253	10.927%	59,890	6,544	
34									79,890	8,533	
35											
36	Sub-Total								1,343,737	101,467	
37	Less - Fort Nelson Division Portion of Long Term Debt								(2,800)	(211)	
38	Total								$1,340,937	$101,256	7.551%

BC GAS UTILITY LTD.

EMBEDDED COST OF LONG-TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2006
($000)

Line No.	Particulars	Issue Date	Maturity Date	Coupon Rate	Principal Amount of Issue	Issue Expense	Net Proceeds of Issue	Effective Interest Cost	Average Principal Outstanding	Annual Cost	Average Embedded Cost
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Series A Purchase Money Mortgage	12-03-1990	09-30-2015	11.800%	$58,943	$855	$58,088	12.054%	$58,943	$7,105	
2	Series B Purchase Money Mortgage	11-30-1991	11-30-2016	10.300%	157,274	2,228	155,046	10.461%	157,274	16,452	
3											
4	2002 Long-Term Debt Issue	09-30-2002	09-30-2012	0.000%	0	0	0	0.000%	0	0	
5	2003 Long-Term Debt Issue	03-31-2003	03-31-2013	5.500%	150,000	1,500	148,500	5.632%	150,000	8,448	
6	2004 Long-Term Debt Issue	09-30-2004	09-30-2014	7.000%	100,000	1,000	99,000	7.142%	100,000	7,142	
7	2005 Long-Term Debt Issue	09-30-2005	09-30-2015	7.000%	250,000	2,500	247,500	7.142%	250,000	17,854	
8	2006 Long-Term Debt Issue	09-30-2006	09-30-2016	7.000%	150,000	1,500	148,500	7.142%	37,808	2,700	
9	2007 Long-Term Debt Issue	09-30-2007	09-30-2017	7.000%	150,000	1,500	148,500	7.142%	0	0	
10											
11	Series F Debentures	08-26-1992	08-26-2002	8.500%	83,980	984	82,996	8.678%	0	0	
12	Series H Debentures	07-28-1993	07-28-2003	8.150%	50,000	507	49,493	8.301%	0	0	
13											
14	Medium Term Note - Series 6	02-09-1995	02-09-2005	9.800%	20,000	380	19,620	10.106%	0	0	
15	Medium Term Note - Series 6	03-15-1995	02-09-2005	9.800%	20,000	(387)	20,387	9.494%	0	0	
16	Medium Term Note - Series 7	06-29-1995	06-29-2005	8.250%	5,000	100	4,900	8.550%	0	0	
17											
18	Medium Term Note - Series 9	10-21-1997	06-02-2008	6.200%	55,000	454	54,546	6.308%	55,000	3,469	
19	Med.Term Note - Series 9 (Re-opened)	11-19-1998	06-02-2008	6.200%	58,000	(681)	58,681	6.036%	58,000	3,501	
20	Med.Term Note - Series 9 (Re-opening)	09-21-1999	06-02-2008	6.200%	75,000	2,053	72,947	6.578%	75,000	4,933	
21	Medium Term Note - Series 11	09-21-1999	09-21-2029	6.950%	150,000	2,137	147,863	7.065%	150,000	10,597	
22											
23	Medium Term Note - Series 12	07-20-2000	07-20-2005	6.500%	200,000	2,622	197,378	6.814%	0	0	
24	Medium Term Note - Series 13	10-16-2000	10-16-2007	6.500%	100,000	728	99,272	6.632%	100,000	6,632	
25	Medium Term Note - Series 14	10-23-2000	10-23-2003	6.000%	50,000	428	49,572	6.317%	0	0	
26	Medium Term Note - Series 15	12-11-2000	12-11-2002	6.000%	75,000	229	74,771	6.177%	0	0	
27	Medium Term Note - Series 16	07-30-2001	07-31-2006	6.150%	100,000	721	99,279	6.320%	58,082	3,671	
28	LILO Obligations - Kelowna							6.969%	29,033	2,023	
29	LILO Obligations - Prince George, Vernon & Nelson							7.250%	48,302	3,502	
30									$1,327,442	$98,029	
31	Debentures										
32	Series D	12-17-1986	12-17-2006	9.750%	20,000	244	19,756	9.945%	19,233	1,913	
33	Series E	06-08-1989	06-07-2009	10.750%	59,890	637	59,253	10.927%	59,890	6,544	
34									79,123	8,457	
35											
36	Sub-Total								1,406,565	106,486	
37	Less - Fort Nelson Division Portion of Long Term Debt								(2,900)	(220)	
38	**Total**								$1,403,665	$106,266	7.571%

BC GAS UTILITY LTD.

EMBEDDED COST OF LONG-TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2007
($000)

Line No.	Particulars	Issue Date	Maturity Date	Coupon Rate	Principal Amount of Issue	Issue Expense	Net Proceeds of Issue	Effective Interest Cost	Average Principal Outstanding	Annual Cost	Average Embedded Cost
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	Series A Purchase Money Mortgage	12-03-1990	09-30-2015	11.800%	$58,943	$855	$58,088	12.054%	$58,943	$7,105	
2	Series B Purchase Money Mortgage	11-30-1991	11-30-2016	10.300%	157,274	2,228	155,046	10.461%	157,274	16,452	
3											
4	2002 Long-Term Debt Issue	09-30-2002	09-30-2012	0.000%	0	0	0	0.000%	0	0	
5	2003 Long-Term Debt Issue	03-31-2003	03-31-2013	5.500%	150,000	1,500	148,500	5.632%	150,000	8,448	
6	2004 Long-Term Debt Issue	09-30-2004	09-30-2014	7.000%	100,000	1,000	99,000	7.142%	100,000	7,142	
7	2005 Long-Term Debt Issue	09-30-2005	09-30-2015	7.000%	250,000	2,500	247,500	7.142%	250,000	17,854	
8	2006 Long-Term Debt Issue	09-30-2006	09-30-2016	7.000%	150,000	1,500	148,500	7.142%	150,000	10,712	
9	2007 Long-Term Debt Issue	09-30-2007	09-30-2017	7.000%	150,000	1,500	148,500	7.142%	37,808	2,700	
10											
11	Series F Debentures	08-26-1992	08-26-2002	8.500%	83,980	984	82,996	8.678%	0	0	
12	Series H Debentures	07-28-1993	07-28-2003	8.150%	50,000	507	49,493	8.301%	0	0	
13											
14	Medium Term Note - Series 6	02-09-1995	02-09-2005	9.800%	20,000	380	19,620	10.106%	0	0	
15	Medium Term Note - Series 6	03-15-1995	02-09-2005	9.800%	20,000	(387)	20,387	9.494%	0	0	
16	Medium Term Note - Series 7	06-29-1995	06-29-2005	8.250%	5,000	100	4,900	8.550%	0	0	
17											
18	Medium Term Note - Series 9	10-21-1997	06-02-2008	6.200%	55,000	454	54,546	6.308%	55,000	3,469	
19	Med.Term Note - Series 9 (Re-opened)	11-19-1998	06-02-2008	6.200%	58,000	(681)	58,681	6.036%	58,000	3,501	
20	Med.Term Note - Series 9 (Re-opening)	09-21-1999	06-02-2008	6.200%	75,000	2,053	72,947	6.578%	75,000	4,933	
21	Medium Term Note - Series 11	09-21-1999	09-21-2029	6.950%	150,000	2,137	147,863	7.065%	150,000	10,597	
22											
23	Medium Term Note - Series 12	07-20-2000	07-20-2005	6.500%	200,000	2,622	197,378	6.814%	0	0	
24	Medium Term Note - Series 13	10-16-2000	10-16-2007	6.500%	100,000	728	99,272	6.632%	79,178	5,251	
25	Medium Term Note - Series 14	10-23-2000	10-23-2003	6.000%	50,000	428	49,572	6.317%	0	0	
26	Medium Term Note - Series 15	12-11-2000	12-11-2002	6.000%	75,000	229	74,771	6.177%	0	0	
27	Medium Term Note - Series 16	07-30-2001	07-31-2006	6.150%	100,000	721	99,279	6.320%	0	0	
28	LILO Obligations - Kelowna							6.969%	28,076	1,957	
29	LILO Obligations - Prince George, Vernon & Nelson							7.250%	46,793	3,392	
30									$1,396,072	$103,513	
31	Debentures										
32	Series D	12-17-1986	12-17-2006	9.750%	20,000	244	19,756	9.945%	0	0	
33	Series E	06-08-1989	06-07-2009	10.750%	59,890	637	59,253	10.927%	59,890	6,544	
34									59,890	6,544	
35											
36	Sub-Total								$1,455,962	$110,057	
37	Less - Fort Nelson Division Portion of Long Term Debt								(3,000)	(227)	
38	Total								$1,452,962	$109,830	7.559%