1998 Annual Report

BC Gas Utility Ltd.

Corporate Profile

BC Gas Utility Ltd. is the largest distributor of natural gas in British Columbia, serving 742,000 residential, commercial and industrial customers in more than 100 communities. BC Gas Utility Ltd. is a wholly owned subsidiary of BC Gas Inc. The Company's head office is in Vancouver, British Columbia.

Management Discussion and Analysis

This discussion and analysis is a review of the operating results, business risks, financial condition and outlook for BC Gas Utility Ltd. ("BC Gas" or the "Company"). This discussion should be read in conjunction with the consolidated financial statements of the Company and related notes.

ANALYSIS OF OPERATING RESULTS

In millions of dollars	**1998**	1997
Gross revenues	**$742.2**	$765.6
Operating expenses		
Cost of natural gas	**338.5**	375.6
Operations and maintenance	**120.6**	124.2
Depreciation and amortization	**61.3**	55.3
Property and other taxes	**31.5**	30.9
	551.9	586.0
Operating income	**190.3**	179.6
Financing costs	**86.8**	83.9
Earnings before restructuring costs, income taxes and non-controlling interest	**$103.5**	$ 95.7

Revenues

Revenues decreased to $742.2 million during 1998 from $765.6 million in 1997. Revenues are set to recover the Company's cost of service, the largest component of which is the cost of natural gas. In 1998, revenues were lower primarily as a result of reductions in the cost of natural gas, which is flowed through into customer rates.

During 1998, 9,992 new customers were added, bringing the total number of gas utility customers to 742,294 at year end. This growth in customers was mainly in the heating market for new single-family houses where natural gas continues to achieve a very high market share.

Industrial sales service increased by 106 terajoules while transportation volumes increased by 164 terajoules from the previous year. The Company earns approximately the same margin regardless of whether a customer contracts for sales or transportation service.

BC Gas has a number of firm and interruptible contracts with the British Columbia Hydro and Power Authority ("BC Hydro") Burrard Thermal Plant near Vancouver. The margin from these contracts in 1998 was $0.3 million, a decrease of $0.7 million from 1997. In addition to these contracts, there was a $5.0 million per annum minimum fixed price contract which expired in September 1998. The revenue from this contract is included in other operating revenue.

To replace these BC Hydro contracts, BC Gas has reached agreement with BC Hydro for firm transportation services to serve BC Hydro's gas fired generation facilities. This agreement, currently under review by the British Columbia Utilities Commission (the "BCUC"), will provide annual transportation revenue of $9.8 million per year, after completion of compression facilities in the Lower Mainland to meet BC Hydro's requirements. Under the new agreement, there are no long term commitments for the supply of gas. Agreement has also been reached regarding BC Hydro's participation in the Southern Crossing Pipeline ("SCP") project and to provide peaking gas supply which form part of a revised SCP application, as discussed below under "Regulation and Rates."

MANAGEMENT DISCUSSION AND ANALYSIS

Expenses

Expenses include the cost of natural gas, operations and maintenance expenses, depreciation and amortization, and property and other taxes. Total operating expenses were $551.9 million in 1998 compared with $586.0 million in 1997.

Cost of natural gas amounted to $338.5 million in 1998 compared with $375.6 million in 1997. The decrease in cost of gas reflects a decrease in the expected price of natural gas bought by the Company on behalf of its customers and a reduction in the volumes sold due to warmer weather.

Operations and maintenance expenses decreased to $120.6 million in 1998 from $124.2 million in 1997. This decrease was due largely to productivity improvements flowing from a significant restructuring program at BC Gas which was implemented in early 1998.

Increased investment in gas plant in service and increased amortization of deferred charges resulted in depreciation and amortization expense rising to $61.3 million in 1998 from $55.3 million in 1997.

Growth in the asset base of the Company, in conjunction with higher tax rates, resulted in property and other taxes increasing by $0.6 million to $31.5 million in 1998.

Financing costs increased to $86.8 million in 1998 from $83.9 million in the previous year largely as a result of higher debt balances and higher short-term interest rates during the year.

Regulation and Rates

BC Gas is regulated by the British Columbia Utilities Commission, which approves rates and tolls for services and the construction of facilities. Traditionally, rates have been set through historical cost rate base and rate of return methodology. Since 1996, incentive rate methodologies have been approved and implemented by the BCUC as part of the rate setting process in order to enhance both value to customers and returns to shareholders.

A number of regulatory deferral accounts are in place to manage the Company's exposure to certain risks. The three most significant deferral accounts relate to the risks of weather, cost of natural gas, and interest rates.

The deferral accounts for weather and cost of natural gas reduce the Company's earnings exposure to these risks by deferring any variances between projected and actual gas consumption and gas costs, and refunding or recovering those variances in future customer rates. Transportation and sales services to industrial customers are not covered by these deferral accounts. As a result of these deferral accounts, variations in reported revenues are caused mainly by changes in gas costs and other components of the Company's cost of service which are recovered in customer rates. Changes in volumes of gas sold to core market customers due to weather or other factors have a less significant impact on reported revenues.

BC Gas also has in place short-term and long-term interest deferral accounts to absorb interest rate fluctuations. The Company's interest deferral accounts effectively locked in the cost of short-term funds attributable to regulated assets during 1998 at 5.0%, compared with 4.0% during 1997.

Allowed Return on Equity

The Company's 1998 allowed ROE of 10.0% was determined based on a formula that applied a risk premium to a forecast of long-term Government of Canada bond yields. The decline from 10.25% in 1997 was a result of a forecast decline in long-term bond yields. For 1999, the Company's allowed ROE has been set at 9.25% using the same formula, reflecting a continued decline in forecasted long-term bond yields.

The table below contains historical information on rate base, allowed ROE and the common equity component used in setting rates for the Company:

	Mid-year Rate Base (in millions)	Common Equity: Allowed Return	Common Equity: Equity Component
1998	**$1,557.8**[1]	**10.00%**	**33%**
1997	$1,517.2	10.25%	33%
1996	$1,441.2	11.00%	33%
1995	$1,333.1	12.00%	33%

[1]preliminary

1998–2000 Revenue Requirement Decision

In June 1997, the Company and other interested parties reached a negotiated settlement to set the revenue requirements for the Company for the years 1998–2000, which was approved by the BCUC on July 23, 1997.

The key points of the settlement are as follows:

- Cost recovery implicit in the 1998 to 2000 rates requires BC Gas to achieve productivity gains in operating and maintenance costs of 2% in each of 1998 and 1999 and 3% in 2000. Restructuring costs of up to $3 million associated with achieving these productivity targets can be deferred and recovered in customer rates. By implementing the restructuring program and other initiatives, the

MANAGEMENT DISCUSSION AND ANALYSIS

Company has taken steps to reach and exceed these productivity targets in each year of the settlement.

- Commencing January 1, 1998, new incentives for demand side management activities and capital expenditure efficiency are available. To the extent that demand side management programs exceed targets, and to the extent that unit costs of certain classes of capital expenditures are lower than the allowed level, the Company has opportunities to generate earnings incremental to what would be allowed in a conventional regulatory framework. These programs did not have a material impact on earnings in 1998.
- An earnings sharing mechanism is incorporated whereby variances in achieved return on equity from that allowed by the BCUC in a given year are to be shared equally with customers. Earnings from the established incentive programs are not included in the earnings sharing mechanism.
- The ratio of overheads capitalized has been, and will be reduced from 22.5% of gross operating and maintenance costs in 1997 to 20% in 1998 and 1999, and to 16% in 2000.
- The allowed common equity component is to remain at 33% of capitalization, and $150 million of outstanding first preference shares are to be refinanced with long-term debt as they become redeemable in 1999 and 2000.
- Through an annual review process, rates for the upcoming year are adjusted to reflect projected changes in factors such as customer growth, industrial revenues, cost of natural gas, interest rates, and taxes.

In addition to the incentives noted above, the Gas Supply Mitigation Incentive Plan provides an incentive for the Company to reduce gas supply costs to customers. The benefits to shareholders under this Plan amounted to $2.4 million (pre-tax) in 1998.

Southern Crossing Pipeline Application

BC Gas has filed an application to the BCUC for a Certificate of Public Convenience and Necessity ("CPCN") in regards to the proposed Southern Crossing Pipeline project. The SCP, which is estimated to cost approximately $348 million, includes 312 kilometres of 24-inch (610-mm) pipeline to be constructed from Yahk, B.C. in the south-eastern corner of the province to Oliver, B.C. at the south end of the Okanagan Valley, as well as related compression facilities. The routing will primarily follow existing pipeline rights-of-way.

In April 1998, an earlier CPCN application to the BCUC for the Southern Crossing Pipeline project was denied. In its decision, the BCUC noted that BC Hydro would have requirements for natural gas to fuel thermal generation projects and directed BC Gas to examine the feasibility of obtaining peak shaving from BC Hydro and its natural gas-fired electricity suppliers. The BCUC further noted "if there is a requirement for new pipeline infrastructure upstream of Huntingdon to serve these loads, BC Gas may wish to re-examine the SCP and attempt to obtain commitments from BC Hydro for capacity on the SCP which would make it a viable alternative."

In November 1998, BC Gas entered into peak service agreements and transportation agreements with BC Hydro and also concluded transportation and peak shaving agreements with a third party customer. Accordingly, a revised CPCN application for the SCP was filed with the BCUC in December 1998. This application is currently under review by the BCUC. A decision from the BCUC is expected in the spring of 1999.

BUSINESS RISKS

Regulatory Treatment

BC Gas, through the rate-making process, relies on the BCUC to set rates that will allow the Company to earn a fair return for its common shareholders. In addition, the BCUC approves the allowable cost of providing service, the capital structure employed to finance the Company's investment in plant and equipment, and various other aspects of the Company's operation. Fair regulatory treatment that allows the Company to earn a risk-adjusted rate of return comparable to that available on alternative investments is essential for ongoing success.

In management's view, the successful negotiation and approval of the 1998–2000 Revenue Requirement settlement is another positive step in the evolution of the Company's regulatory relationship with the BCUC and its customers. The incentives in that settlement, which are subject to renegotiation for the years after 2000, demonstrate that incentive regulatory arrangements have gained the support of the BCUC and customer groups as an approach that can streamline the regulatory process while implementing incentives which benefit, and align the interests of, both customers and shareholders.

MANAGEMENT DISCUSSION AND ANALYSIS

Long-term Competitiveness

As the energy industry in North America continues to experience structural change, it is essential that BC Gas challenge the level of ongoing operating expenses and commitment of capital resources. Management of the Company has worked with the BCUC to incorporate productivity targets, in the form of decreased operations and maintenance spending per customer of 2%, 2% and 3% for 1998, 1999 and 2000 respectively. In addition, a new capital expenditure efficiency mechanism was incorporated into the 1998–2000 settlement, and policies for mains extensions continue to be refined and improved, thereby reducing the required net investment in each new customer addition.

Future competition in the energy market will introduce new risks to BC Gas. Challenging its own investment criteria, as well as those imposed on its customers from external forces, is an important component of the Company's strategy for maintaining the long-term competitive position of natural gas as an economic source of energy for British Columbians.

Customer Additions

New customer additions at BC Gas are typically a result of population growth and new housing starts. In recent years, British Columbia has experienced declining immigration, population growth and housing starts which has resulted in a similar decline in new customer additions for the Company. BC Gas anticipates that the recent customer addition rates may continue for the next several years. The Company is working to expand its market for natural gas service by increasing its penetration of the multiple family development market.

Gas Supply

BC Gas continues to face significant physical risk related to gas supply disruption as it is dependent on a limited selection of pipeline and storage providers. This risk is particularly acute in the Vancouver-Lower Mainland service area where the majority of BC Gas' core market customers are located. These customers rely primarily on the transportation services of one pipeline company. In addition, the limited transportation and storage alternatives present risks of both supply disruption and lack of access to competitive sources of natural gas.

To the extent possible, BC Gas has attempted to minimize gas supply and price risk through the use of long-term transportation, storage and supply contracts, hedging instruments and a diverse supply portfolio. In 1998, management has actively pursued several initiatives to allow for the transportation of gas supplies through alternate pipeline infrastructure. Specifically, BC Gas' application before the BCUC for the Southern Crossing Pipeline is intended to address this risk as well as to minimize the delivered cost of gas to the Company's core customers over the long term.

During the SCP hearing before the BCUC in the fall of 1997, it became apparent from the evidence of several participants in the hearing that the regional peak day demand in British Columbia and the U.S. Pacific Northwest significantly exceeds the supply available from the existing infrastructure. Management believes that the SCP is an integral factor in meeting the growing demands for natural gas as well as reducing consumer exposure to supply disruptions and related price increases should the region experience either a cold winter or failure in gas producing, storage or pipeline facilities.

In addition, BC Gas is monitoring with interest the Alliance Pipeline project, which will transport natural gas from northern British Columbia to Chicago, as it has the potential to alter the supply of B.C. basin gas available to consumers in British Columbia. The Alliance Pipeline is expected to transport 300 to 500 Mmcf/d, or approximately 15% to 25% of current production levels in northern B.C., away from the province as early as 2000. The effect of projects such as Alliance underscore the need for the BC Gas system to be better connected to the North American gas pipeline grid in order to have competitive access to alternate gas supply sources to ensure reliable supply and reasonable gas supply costs for gas consumers in British Columbia.

LIQUIDITY AND CAPITAL RESOURCES

Changes in non-cash operating working capital, offset by an increase in net earnings after adjusting for items not involving cash, resulted in a decrease in cash flow from operating activities to $34.1 million in 1998 from $163.8 million in 1997.

Capital expenditures totalled $110.5 million in 1998 compared with $105.4 million in 1997. The $5.1 million increase in capital spending was due primarily to the implementation of a new business information system which will support improved decision making and greater efficiencies; offset by lower spending requirements for mains and services from fewer customer additions compared to 1997.

MANAGEMENT DISCUSSION AND ANALYSIS

The capital spending in 1998 is summarized as follows:

In millions of dollars

Mains, services and engineering projects	$ 40.5
Land and buildings	3.3
Systems and computer hardware	25.8
Other	11.7
	81.3
Capitalized overhead	29.2
	$110.5

Coverage Ratios

Due to the capital intensive nature of the Company's businesses and the need to raise debt frequently in the fixed income market, maintenance of its financial ratios is a priority for BC Gas. The most significant ratios are considered to be interest coverage and total debt to shareholders' equity. These are presented below on a consolidated basis:

	1998	1997
Interest coverage	**2.19**	2.14
Debt to shareholders' equity	**1.59:1**	1.71:1

Debt Ratings

Securities issued by BC Gas are rated by two Canadian bond rating companies, the Dominion Bond Rating Service ("DBRS") and the Canadian Bond Rating Service ("CBRS"). The ratings assigned to securities issued by BC Gas are reviewed by DBRS and CBRS on an annual basis. In 1998, CBRS raised its rating on the unsecured long-term debt, 7.10% Preference shares and 6.32% Preference shares of BC Gas from B++, P-3 (High) and P-3 to B++ (High), P-2 (Low) and P-3 (High), respectively. In addition, CBRS changed its Outlook on its ratings of BC Gas unsecured long-term debt from Stable to Positive. The table below summarizes the ratings assigned to the Company's various securities at December 31, 1998.

	DBRS	CBRS
Commercial paper	R-1 (Low)	A-1
Unsecured debentures	A	B++ (High)
Medium term note debentures and medium term notes	A	B++ (High)
Purchase money mortgages	A	A (Low)
7.10% Preference shares	Pfd-3	P-2 (Low)
6.32% Preference shares	Pfd-3	P-3 (High)

Projected Capital Expenditures

BC Gas has estimated total capital expenditures of $116.1 million in 1999 which the Company expects to finance with a combination of long-term debt issuance, short-term borrowings and internally generated funds. The breakdown of projected capital expenditures for 1999, excluding capital expenditures for the proposed Southern Crossing Pipeline, is as follows:

In millions of dollars

Mains, services and engineering projects	$ 61.7
Land and buildings	2.1
Systems and computer hardware	11.4
Other	11.6
	86.8
Capitalized overhead	29.3
	$116.1

Public Issues

During the year, BC Gas issued $108 million of medium term note debentures at a weighted average interest rate of 5.69%. This compares with $55 million issued in 1997 at an interest rate of 6.20%.

Lines of Credit

The Company has lines of credit in place totalling $350 million to finance cash requirements. These lines enable the Company to borrow directly from its bankers, issue bankers' acceptances and support issued commercial paper. Bank lines of $120 million were unutilized at the end of 1998. Virtually all short-term cash needs are funded through commercial paper and bankers' acceptances in the Canadian market at rates generally below bank prime.

Financial Instruments and Risk Management

BC Gas has undertaken a natural gas price risk management program on behalf of its customers to manage the price volatility of its forecast system gas supply. Part of this program involves the use of financial instruments to effectively fix the price of baseload gas supply.

OTHER MATTERS

Year 2000 Issue

The Year 2000 issue refers to the risk that computers and other devices that rely on microprocessor technology may fail to recognize the Year 2000 if their program logic uses two digits to represent years. BC Gas' business processes and operations rely extensively on computer technology. In addition, the Company relies on third party suppliers to provide products and services, some of which are essential to the operations of BC Gas. A major failure of key company systems or disruption of the delivery of essential products or services as a result of a Year 2000 related problem has the potential to seriously disrupt the business operations of BC Gas.

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Recognizing the potential risks involved, BC Gas has completed a company-wide program to assess the potential impact of the Year 2000 issue and system upgrades and conversions are underway. A number of planned initiatives to upgrade the Company's systems have been underway for some time, including a $21 million business information system which was successfully implemented in January 1999. Over and above these capitalized initiatives, expenses for remediation and testing are expected to be between $2 and $3 million, based on current estimates.

The Company expects to complete remediation and testing of its business critical systems by June 30, 1999. Based on the testing done to date on control systems and embedded systems, the Company believes that the Year 2000 issue will not cause disruptions in service. However, the Company cannot be certain that all aspects of the Year 2000 issue affecting the Company, including those aspects relating to the Company's customers, suppliers and other third parties, will be fully resolved. Accordingly, the Company is working closely with major suppliers and customers to identify and rectify potential problems, and is developing contingency plans where possible to deal with failures which could impact its essential services and core operations as a result of the Year 2000 issue.

Collective Agreements

Collective agreements with BC Gas employees represented by the Office and Professional Employees International Union (Local 378) and the International Brotherhood of Electrical Workers (Local 213) expired March 31, 1998. Negotiations are continuing.

OUTLOOK

In 1998, the Company developed a focused business strategy to position BC Gas to capitalize on new opportunities. The Company is taking action to secure and optimize its base businesses, grow from these core businesses into new markets, and position BC Gas to sell new products and services to existing customers.

Although the economy in British Columbia is experiencing slower growth than in previous years, BC Gas' exposure to an economic slowdown is relatively limited, given its mature, diversified customer base and its ability to correct for unanticipated developments in the annual rate resetting process. As a result of the lower economic growth rate, however, customer additions have declined, with a corresponding reduction in rate base growth. The Company is also addressing the challenge of reductions in the allowed return on equity.

As the largest natural gas distributor in British Columbia, BC Gas is well positioned to thrive in a less regulated and more competitive environment. Competition from non-utility participants in the energy services business as well as from utilities outside the province is increasing as the utility environment becomes less regulated and increasingly focused on delivering choices for customers. Steps have been taken to improve productivity and realign internal systems to a market orientation. These actions are expected to improve the Company's ability to deliver high quality products and services at a competitive price.

Notwithstanding the shorter term challenges facing BC Gas, the Company is committed to sustaining earnings growth. The Southern Crossing project, if approved, will create significant shareholder value. In addition, a number of actions have been taken to enhance productivity, renew business processes and refocus the Company to meet customer needs. The Company is well positioned to capitalize on its strategic plan and deliver superior value to shareholders in a competitive energy services market.

Management's Responsibility

The consolidated financial statements have been prepared by management, which is responsible for the integrity and objectivity of this information. These statements have been prepared in conformity with generally accepted accounting principles and, where appropriate, include some amounts that are based on management's best estimates and judgements. The financial information presented elsewhere in the annual report is consistent with that in the consolidated financial statements.

Management has established systems of internal control which are designed to provide reasonable assurance that assets are safeguarded from loss and that reliable financial records are maintained. These systems are monitored by internal auditors.

KPMG, the auditors appointed by the shareholders, have reviewed the systems of internal control and examined the consolidated financial statements in accordance with generally accepted auditing standards to enable them to express an independent opinion on the financial statements. Their report is set out below.

The Board of Directors, through its Audit Committee, oversees management's responsibilities for financial reporting and internal control. The Audit Committee meets with the internal auditors, the independent auditors and management to discuss auditing and financial matters and to review the consolidated financial statements and the independent auditors' report. The Audit Committee reports its findings to the Board for consideration in approving the financial statements for issuance to the shareholders.

John M. Reid
President and Chief Executive Officer

Milton C. Woensdregt
Senior Vice President, Finance
and Chief Financial Officer and Treasurer

Vancouver, Canada
February 2, 1999

Auditors' Report to the Shareholders

We have audited the consolidated statements of financial position of BC Gas Utility Ltd. as at December 31, 1998 and 1997 and the consolidated statements of earnings, retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 1998 and 1997 and the results of its operations and its cash flows for the years then ended in accordance with generally accepted accounting principles. As required by the Company Act (British Columbia), we report that, in our opinion, these principles have been applied on a consistent basis.

KPMG LLP
Chartered Accountants

Vancouver, Canada
February 2, 1999

Consolidated Statements of Earnings

In millions of dollars *Years ended December 31*	**1998**	1997
REVENUES		
Natural gas sales and transportation	**$ 724.5**	$ 743.5
Other operating revenue *(note 4)*	**17.7**	22.1
	742.2	765.6
EXPENSES		
Cost of natural gas	**338.5**	375.6
Operation and maintenance	**120.6**	124.2
Depreciation and amortization	**61.3**	55.3
Property and other taxes	**31.5**	30.9
	551.9	586.0
OPERATING INCOME	**190.3**	179.6
Financing costs *(note 6)*	**86.8**	83.9
Restructuring costs	**–**	9.4
Earnings before income taxes	**103.5**	86.3
Income taxes *(note 7)*		
Current	**49.5**	41.2
Deferred reduction	**–**	(2.7)
	49.5	38.5
NET EARNINGS	**54.0**	47.8
Dividends on 6.32% preference shares	**(4.7)**	(4.7)
Recovery of Part VI.1 tax	**0.1**	–
EARNINGS APPLICABLE TO COMMON SHARES	**$ 49.4**	$ 43.1

Consolidated Statements of Retained Earnings

In millions of dollars *Years ended December 31*	**1998**	1997
Balance, beginning of year	**$ 47.1**	$ 45.0
Net earnings	**54.0**	47.8
	101.1	92.8
Dividends on		
6.32% preference shares	**4.7**	4.7
Common shares	**42.3**	41.6
Recovery of Part VI.1 tax	**(0.1)**	–
Reduction of income taxes related to share issue costs	**(0.6)**	(0.6)
	46.3	45.7
Balance, end of year	**$ 54.8**	$ 47.1

Consolidated Statements of Financial Position

In millions of dollars *December 31*	**1998**	1997
ASSETS		
Current assets		
Accounts receivable	**$ 148.8**	$ 127.6
Inventories of gas in storage and supplies	**28.4**	22.3
Prepaid expenses	**3.3**	4.2
Rate stabilization accounts	**14.6**	–
Income and other taxes receivable	**4.1**	–
	199.2	154.1
Property, plant and equipment *(note 1)*	**1,729.6**	1,675.1
Other assets		
Deferred charges	**12.7**	21.0
Long-term receivables and investments	**2.1**	2.0
	14.8	23.0
	$1,943.6	$1,852.2
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Bank indebtedness	**$ 10.8**	$ 1.5
Short-term notes	**219.0**	189.0
Accounts payable and accrued liabilities	**158.7**	134.0
Income and other taxes payable	**–**	35.5
Rate stabilization accounts	**–**	24.4
Current portion of long-term debt *(note 2)*	**191.2**	93.5
	579.7	477.9
Long-term debt *(note 2)*	**678.8**	761.8
Deferred income taxes	**0.9**	0.9
	1,259.4	1,240.6
Shareholders' equity		
Capital stock *(note 3)*	**549.0**	484.1
Contributed surplus	**80.4**	80.4
Retained earnings	**54.8**	47.1
	684.2	611.6
	$1,943.6	$1,852.2

Approved by the Board:

Ronald L. Cliff
Director

John M. Reid
Director

Consolidated Statements of Cash Flows

In millions of dollars *Years ended December 31*	**1998**	1997
Cash flows provided by (used for)		
OPERATING ACTIVITIES		
Net earnings	**$ 54.0**	$ 47.8
Adjustments for non-cash items		
Depreciation and amortization	**61.3**	55.3
Deferred income taxes	**–**	(2.7)
Allowance for equity funds used during construction	**(0.9)**	(0.7)
	114.4	99.7
Changes in non-cash operating working capital	**(80.3)**	64.1
	34.1	163.8
INVESTING ACTIVITIES		
Property, plant and equipment	**(110.5)**	(105.4)
Other assets	**3.8**	8.3
	(106.7)	(97.1)
FINANCING ACTIVITIES		
Increase (decrease) of short-term notes	**30.0**	(78.4)
Increase in long-term debt	**108.3**	56.1
Reduction of long-term debt	**(93.6)**	(7.7)
Issue of common shares, net of issue costs	**64.9**	–
Dividends on 6.32% preference and common shares	**(47.0)**	(46.3)
Recovery of Part VI.1 tax	**0.1**	–
Reduction of income taxes related to share issue costs	**0.6**	0.6
	63.3	(75.7)
Net decrease in cash	**(9.3)**	(9.0)
Cash (bank indebtedness) at beginning of year	**(1.5)**	7.5
Bank indebtedness at end of year	**$ (10.8)**	$ (1.5)
Supplemental disclosure of cash flow information		
Financing costs paid in the year	**$ 89.6**	$ 84.2
Income taxes paid in the year	**43.6**	2.2

Cash is defined as cash and short-term investments or bank indebtedness.

Significant Accounting Policies

The preparation of these consolidated financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts in the financial statements and the disclosure of contingent assets and liabilities. A significant area requiring the use of management estimates relates to the determination of useful lives for depreciation and amortization. The consolidated financial statements have, in management's opinion, been properly prepared within reasonable limits of materiality and within the framework of the significant accounting policies summarized below:

PRINCIPLES OF CONSOLIDATION

The consolidated financial statements include the accounts of the Company and its two subsidiaries, Squamish Gas Co. Ltd. ("Squamish Gas") and Inland Energy Corp.

REGULATION

The Company and Squamish Gas are primarily engaged in the transmission and retail distribution of natural gas for residential, commercial and large industrial customers in British Columbia and are subject to the regulation of the British Columbia Utilities Commission ("the Commission"). The Commission exercises statutory authority over such matters as rate of return, construction and operation of facilities, accounting practices and rates.

INVENTORIES OF GAS IN STORAGE AND SUPPLIES

Inventories of gas in storage and supplies are valued at cost determined mainly on a moving-average basis.

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment are stated at cost which includes all direct costs, betterments, an allocation of overhead costs and an allowance for funds used during construction.

Depreciation of assets is provided on a straight-line basis on plant in service at rates approved by the Commission. The cost of depreciable property retired, together with removal costs less salvage, is charged to accumulated depreciation.

No provision for future removal and site restoration costs has been accrued for regulated operations as the extent of such costs is not currently determinable. Management expects that such costs would be recoverable through future rates.

DEFERRED CHARGES

The Company defers certain charges which the Commission requires or permits to be recovered through future rates. They are amortized over various periods depending on the nature of the charges and include financing costs such as long-term debt issue costs which are amortized over the original lives of the related debt.

RATE STABILIZATION ACCOUNTS

The Company is authorized by the Commission to maintain two rate stabilization accounts to mitigate the effect on its earnings of unpredictable and uncontrollable factors, principally temperature and cost of natural gas fluctuations.

The gas cost reconciliation account ("GCRA") accumulates unforecasted changes in natural gas costs and natural gas cost recoveries. The revenue stabilization adjustment mechanism ("RSAM") accumulates the margin impact of variations in the actual use for residential and commercial customers from forecast use. The balances are amortized as ordered by the Commission.

REVENUES

Revenue from natural gas sales is recorded on the basis of regular meter readings and estimates of customer usage since the last meter reading date to the end of the reporting period.

PENSION PLANS

The cost of pension entitlements earned by employees is determined annually by independent actuaries utilizing the projected benefit method prorated on services. This cost is expensed as services are rendered and reflects management's best estimates of expected plan investment performance, salary growth, future terminations, mortality rates and retirement ages of plan members. Adjustments which result from plan amendments, changes in assumptions and experience gains and losses are amortized over the expected average remaining service life of the employee group covered by the plan.

POST RETIREMENT BENEFITS OTHER THAN PENSIONS

The Company provides certain health care and life insurance benefits to eligible retirees and their dependants. The cost of providing these benefits is expensed as paid which matches the recovery in rates.

INCOME TAXES

The Company and Squamish Gas account for income taxes for regulated operations as prescribed by the Commission. This includes following the taxes payable method of accounting for income taxes, accounting for certain assets and the rate stabilization accounts on a net of tax basis and amortizing deferred income taxes as approved by the Commission. Under the taxes payable method, deferred income taxes are not recorded for significant timing differences in reporting revenue and expenses for financial statement purposes and income tax purposes. This method is followed as there is reasonable expectation that all taxes payable in future years will be recoverable from customers at that time.

Notes to Consolidated Financial Statements

Tabular amounts in millions of dollars, except where stated otherwise
Years ended December 31, 1998 and 1997

1. PROPERTY, PLANT AND EQUIPMENT

1998	Depreciation rates	Cost	Accumulated depreciation	Net book value
Natural gas pipeline systems	**1% – 10%**	**$1,813.7**	**$286.3**	**$1,527.4**
Plant, buildings and equipment	**1% – 20%**	**226.1**	**70.3**	**155.8**
Land and land rights	**0% – 5 %**	**46.6**	**0.2**	**46.4**
		$2,086.4	**$356.8**	**$1,729.6**

1997	Depreciation rates	Cost	Accumulated depreciation	Net book value
Natural gas pipeline systems	1% – 10%	$1,746.8	$255.9	$1,490.9
Plant, buildings and equipment	1% – 20%	208.2	69.9	138.3
Land and land rights	0% – 5%	46.1	0.2	45.9
		$2,001.1	$326.0	$1,675.1

The composite depreciation rate on regulated property, plant and equipment for the year ended December 31, 1998 is approximately 3.0% (1997 – 3.0%).

Included in property, plant and equipment are assets under capital leases with a cost of $13.0 million (1997 – $20.2 million) and related accumulated depreciation of $6.0 million (1997 – $10.9 million).

2. LONG-TERM DEBT

	1998	1997
(a) Purchase Money Mortgages:		
11.80% Series A, due September 30, 2000 or September 30, 2015 if extended by holder	**$ 75.0**	$ 75.0
10.30% Series B, due September 30, 2016	**200.0**	200.0
(b) Debentures:		
9.75% Series D, due December 17, 2006	**20.0**	20.0
10.55% Series E, due June 8, 1999; 10.75% to June 8, 2009 if extended by holder	**60.0**	60.0
8.50% Series F, due August 26, 2002	**100.0**	100.0
7.25% Series G, due July 28, 1998	**–**	75.0
8.15% Series H, due July 28, 2003	**50.0**	50.0
(c) Medium Term Note Debentures and Medium Term Notes:		
8.80% Series 5, due October 14, 1999	**55.0**	55.0
9.80% Series 6, due February 9, 2005	**40.0**	40.0
6.20% Series 9, due June 2, 2008	**113.0**	55.0
5.10% Series 10, due February 2, 2001	**50.0**	–
Various series, weighted average interest rate of 7.05% (1997 – 7.48%) with maturities ranging from 2001 to 2005 (1997 – 1998 to 2005)	**25.0**	41.0
(d) Preference Shares:		
7.10% Cumulative Redeemable Retractable First Preference Shares	**75.0**	75.0
Obligations under capital leases, weighted average interest rate of 6.66% (1997- 5.73%)	**7.0**	9.3
Total long-term debt	**870.0**	855.3
Less current portion of long-term debt	**191.2**	93.5
	$ 678.8	$ 761.8

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(a) Purchase Money Mortgages
The Series A and Series B Purchase Money Mortgages are secured equally and rateably by a first fixed and specific mortgage and charge on the Company's Coastal Division assets, and are subject to the restrictions of the Trust Indenture dated December 3, 1990. The aggregate principal amount of Purchase Money Mortgages that may be issued under the Trust Indenture is limited to $425 million.

(b) Debentures
The debentures are unsecured obligations but are subject to the restrictions of the Trust Indenture dated November 1, 1977, as amended and supplemented.

(c) Medium Term Note Debentures and Medium Term Notes
The Medium Term Note Debenture Program established in 1993 and renewed in 1995 and 1997 allows for the issuance of up to $400 million aggregate principal amount of debentures during the two year period ending November 26, 1999. Issued debentures are unsecured obligations but are subject to the terms of the Trust Indenture dated November 1, 1977 (see note 2(b)).

(d) Preference Shares
These preference shares are redeemable at the option of the Company on or after September 30, 1999 and are retractable at the option of the holder on September 30, 1999, at $25 per share plus accrued and unpaid dividends.

The Series B Purchase Money Mortgages and Series F and Series H Debentures are redeemable in whole or in part at the option of the Company at a price equal to the greater of the Canada Yield Price, as defined in the applicable Trust Indenture, and the principal amount of the debt to be redeemed, plus accrued and unpaid interest to the date specified for redemption. The Canada Yield Price is calculated as an amount that provides a yield slightly above the yield on an equivalent maturity Government of Canada bond.

Assuming the Series A Purchase Money Mortgages and Series E Debentures are not extended by the holders and the 7.1% Preference Shares are redeemed by the Company or retracted by the holders, required principal repayments over the next five years are as follows:

1999	$ 191.2
2000	76.3
2001	71.3
2002	101.3
2003	51.3

3. CAPITAL STOCK

(a) Share Capital
The Company is authorized to issue 500,000,000 common shares, 100,000,000 first preference shares and 100,000,000 second preference shares, all without par value. Issued share capital is comprised of the following:

	1998	1997
6.32% cumulative redeemable first preference shares, 3,000,000 shares issued	**$ 75.0**	$ 75.0
Common shares	**474.0**	409.1
	$ 549.0	$ 484.1

(b) 6.32% Cumulative Redeemable First Preference Shares
These shares are redeemable at the option of the Company at $25 per share on or after October 31, 2000, and are exchangeable at the option of the Company on or after October 31, 2000 for common shares of the Company's parent, BC Gas Inc., at a price equal to the greater of $3 and 95% of the weighted average trading price of the common shares at that time.

The shares are exchangeable at the option of the holder on or after January 31, 2001 for common shares of BC Gas Inc. at a price equal to the greater of $3 and 95% of the weighted average trading price of the common shares at that time, subject to the right of the Company to redeem the shares for cash or to find substitute purchasers for the preference shares.

(c) Common Shares
On October 22, 1998, the Company issued 3,000,000 shares to BC Gas Inc. for $64.9 million. All 48,413,342 (1997 – 45,413,342) issued and outstanding common shares of the Company at December 31, 1998 and 1997 were held by BC Gas Inc.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

4. OTHER OPERATING REVENUE

	1998	1997
Burrard Thermal contract revenue	$ 5.0	$ 5.0
Connection charges	3.9	4.4
Vancouver Island pipeline wheeling charges	3.8	3.7
Off-system sales incentive program	2.4	4.6
Other	1.7	3.7
Allowance for equity funds used during construction	0.9	0.7
	$ 17.7	$ 22.1

5. PENSION PLANS

The Company has defined benefit pension plans available for its employees. As at December 31, 1998, actuarial projections of employees' compensation levels to the time of retirement indicate that the present value of accrued pension benefits is $118.9 million (1997 – $109.5 million) and the market related value of the assets available to provide these benefits is $126.0 million (1997 – $113.0 million).

6. FINANCING COSTS

	1998	1997
Interest and expense on long-term debt	$ 71.7	$ 71.0
Other interest	10.7	8.0
Interest capitalized	(0.9)	(0.4)
	81.5	78.6
Dividends on 7.1% preference shares	5.3	5.3
	$ 86.8	$ 83.9

7. INCOME TAXES

(a) Variation in Effective Income Tax Rate

Consolidated income taxes vary from the amount that would be computed by applying the federal and British Columbia combined statutory income tax rate of 45.62% to earnings before income taxes as shown in the following table:

	1998	1997
Earnings before income taxes	$ 103.5	$ 86.3
Combined statutory income taxes in the Province of British Columbia	$ 47.2	$ 39.4
Add (deduct) tax effect of:		
Capital cost allowance and other deductions claimed for income tax purposes over amounts recorded for accounting purposes	(7.4)	(6.1)
Large Corporations Tax	4.1	3.4
Permanent differences between accounting and taxable income	3.8	4.0
Amortization of deferred income taxes	–	(2.7)
Other	1.8	0.5
Actual consolidated income taxes	$ 49.5	$ 38.5

(b) Deferred Income Taxes

Accumulated deferred income taxes which have not been recorded in the accounts amount to $201.2 million at December 31, 1998 (1997 – $193.8 million).

8. FINANCIAL INSTRUMENTS

(a) Fair Value of Financial Instruments

The carrying value of accounts receivable, bank indebtedness, short-term notes and accounts payable and accrued liabilities approximates their fair value due to the relatively short period to maturity of the instruments.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The fair value of the Company's long-term debt, calculated by discounting the future cash flow of each debt issue at the estimated yield to maturity for the same or similar issues at December 31, 1998, or by using available quoted market prices, is estimated at $1,071.4 million (1997 – $1,042.3 million). The majority of the Company's long-term debt relates to regulated operations which enables the Company to recover the existing financing charges through rates.

Fair value estimates are made at a specific point in time, based on relevant market information and information about the financial instrument. These estimates cannot be determined with precision as they are subjective in nature and involve uncertainties and matters of judgement.

(b) Derivative Instruments

The Company uses derivative instruments to hedge its exposures to fluctuations in energy prices and foreign currency exchange rates. These instruments are for terms of less than one year.

Natural gas derivatives are used to manage natural gas price risk in the Company. The majority of the natural gas supply contracts have floating prices for natural gas, rather than fixed prices. On behalf of customers, the Company uses natural gas price swap contracts to fix the effective purchase price. Any differences between the effective cost of natural gas purchased and the price of natural gas used for rate making purposes are managed through the regulatory process whereby differences are recorded in a deferral account and passed through to customers in future rates.

Interest rate and foreign currency risk of the Company is managed mainly through the regulatory process. As at December 31, 1998, $190 million of short-term borrowings of the Company were subject to interest rate deferral accounts. Foreign currency risk of the Company relates mainly to purchases and sales of natural gas denominated in U.S. dollars, and is thereby managed through the regulatory process.

The following table provides fair value information on the Company's natural gas derivative instruments. The natural gas derivatives fair value reflects only the value of the natural gas derivatives and not the offsetting change in the value of the underlying future purchases of natural gas. These fair values reflect the estimated amounts the Company would receive or pay to terminate the contracts at the stated dates.

	1998		1997	
	Asset (liability)		Asset (liability)	
	Carrying value	**Fair value**	Carrying value	Fair value
Natural gas derivatives	**$ (4.7)**	**$ (4.6)**	$ (4.8)	$ (8.4)

The Company is exposed to credit risk in the event of non-performance by counterparties to derivative instruments. Because it deals with high credit quality institutions in accordance with its established credit approval practices, the Company does not expect any counterparties to fail to meet their obligations.

9. COMMITMENT

The Company has entered into operating leases in respect of its head office and other premises. Minimum payments under these leases are approximately $5.2 million in each of the next four years and $21.6 million in aggregate.

10. UNCERTAINTY DUE TO THE YEAR 2000 ISSUE

The Year 2000 Issue arises because many computerized systems use two digits rather than four to identify a year. Date-sensitive systems may recognize the year 2000 as 1900 or some other date, resulting in errors when information using year 2000 dates is processed. In addition, similar problems may arise in some systems which use certain dates in 1999 to represent something other than a date. The effects of the Year 2000 Issue may be experienced before, on, or after January 1, 2000, and, if not addressed, the impact on operations and financial reporting may range from minor errors to significant systems failure which could affect the Company's ability to conduct normal business operations. The Company has completed an enterprise-wide program to assess the potential impact of the Year 2000 Issue and system upgrades and conversions are underway. The Company is working closely with major suppliers and customers to identify and rectify potential problems. However, it is not possible to be certain that all aspects of the Year 2000 Issue affecting the Company, including those related to the efforts of customers, suppliers, or other third parties, will be fully resolved.

Operating Summary – Unaudited

Dollar amounts in millions *Years ended December 31*	1998	1997	1996	1995	1994
Revenues					
Residential	**$ 423.1**	$ 431.1	$ 405.5	$ 405.3	$ 385.4
Commercial	**226.3**	246.9	231.3	241.6	230.1
Small industrial	**22.5**	17.3	14.7	14.5	10.8
Large industrial and other	**19.1**	19.7	17.2	23.1	36.4
Total natural gas sales revenue	**691.0**	715.0	668.7	684.5	662.7
Transportation	**33.5**	28.5	33.7	28.0	23.0
Other	**17.7**	22.1	19.3	19.6	18.8
Total natural gas revenue	**$ 742.2**	$ 765.6	$ 721.7	$ 732.1	$ 704.5
Sales (PJs)*					
Residential	**72.0**	73.4	80.2	68.7	68.7
Commercial	**45.4**	50.5	55.2	48.2	47.4
Small industrial	**5.9**	5.1	4.3	3.8	2.9
Large industrial and other	**6.5**	7.3	4.8	9.5	14.7
Total natural gas sales	**129.8**	136.3	144.5	130.2	133.7
Transportation	**57.7**	57.5	59.8	56.0	51.0
Total sales and transportation	**187.5**	193.8	204.3	186.2	184.7
Customers at year end					
Residential	**664,584**	655,517	641,364	625,826	609,779
Commercial	**76,547**	75,714	74,443	72,631	70,720
Small industrial	**411**	340	233	193	134
Large industrial and other	**84**	129	131	135	152
Transportation	**668**	602	230	213	174
	742,294	732,302	716,401	698,998	680,959
Customer statistics*					
Average use per customer (GJs)					
Residential	**109**	113	127	111	115
Commercial	**596**	673	750	673	681
Average rate per GJ					
Residential	**$ 5.88**	$ 5.87	$ 5.05	$ 5.90	$ 5.61
Commercial	**$ 4.98**	$ 4.89	$ 4.19	$ 5.01	$ 4.86
Natural gas purchased (PJs)*	**147.8**	149.3	149.4	156.0	161.0
Maximum day sendout (TJs)*					
(including interruptible)	**1,359.4**	1,360.9	1,418.8	1,283.5	1,203.8
Degree Days (Base 18°C)					
Coastal					
Actual	**2,554**	2,677	3,077	2,604	2,676
Normal	**2,796**	2,846	2,846	2,896	2,896
Interior					
Actual	**3,563**	3,911	4,609	3,913	3,739
Normal	**3,974**	3,969	3,969	4,048	4,048

*Sales statistics are stated in SI (metric) units

Corporate Information

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REGISTRAR AND TRANSFER AGENT
Shareholder accounts, including dividend payments, direct deposit service and the transfer of shares are handled by the Company's registrar and transfer agent:

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Vancouver, B.C. V6E 2K3
Telephone: (604) 688-4330
Toll Free: 1-800-387-0825

DUPLICATE ANNUAL AND INTERIM REPORTS
To eliminate duplicate mailings of annual and quarterly reports, please contact CIBC Mellon Trust Company.

STOCK EXCHANGE LISTINGS
The Company's 7.10% Cumulative Redeemable Retractable First Preference Shares are listed for trading on The Toronto Stock Exchange under the symbol – BGU.PR.B.

The Company's 6.32% Redeemable First Preference Shares are listed for trading on The Toronto Stock Exchange under the symbol – BGU.PR.C.

EMPLOYEE SHARE PURCHASE PLAN
Employees of BC Gas Utility Ltd. may contribute from 2% to 6% of their earnings through payroll deductions to purchase shares in BC Gas Inc. Shares are purchased at 100% of the market price. BC Gas Inc. pays all administration costs associated with the plan.

INTERNET
Website: www.bcgas.com

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Assistant Corporate Secretary

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2 Member of the Audit Committee
3 Member of the BC Gas Inc. Corporate Governance Committee
4 Member of the Environment and Safety Committee
5 Member of the Management Resources Committee

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