

PACIFIC NORTHERN GAS LTD. 2004 ANNUAL REPORT



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Pacific Northern Gas Ltd. delivers natural gas to customers in west-central British Columbia and through its subsidiary, Pacific Northern Gas (N.E.) Ltd., to customers in the province's northeast.

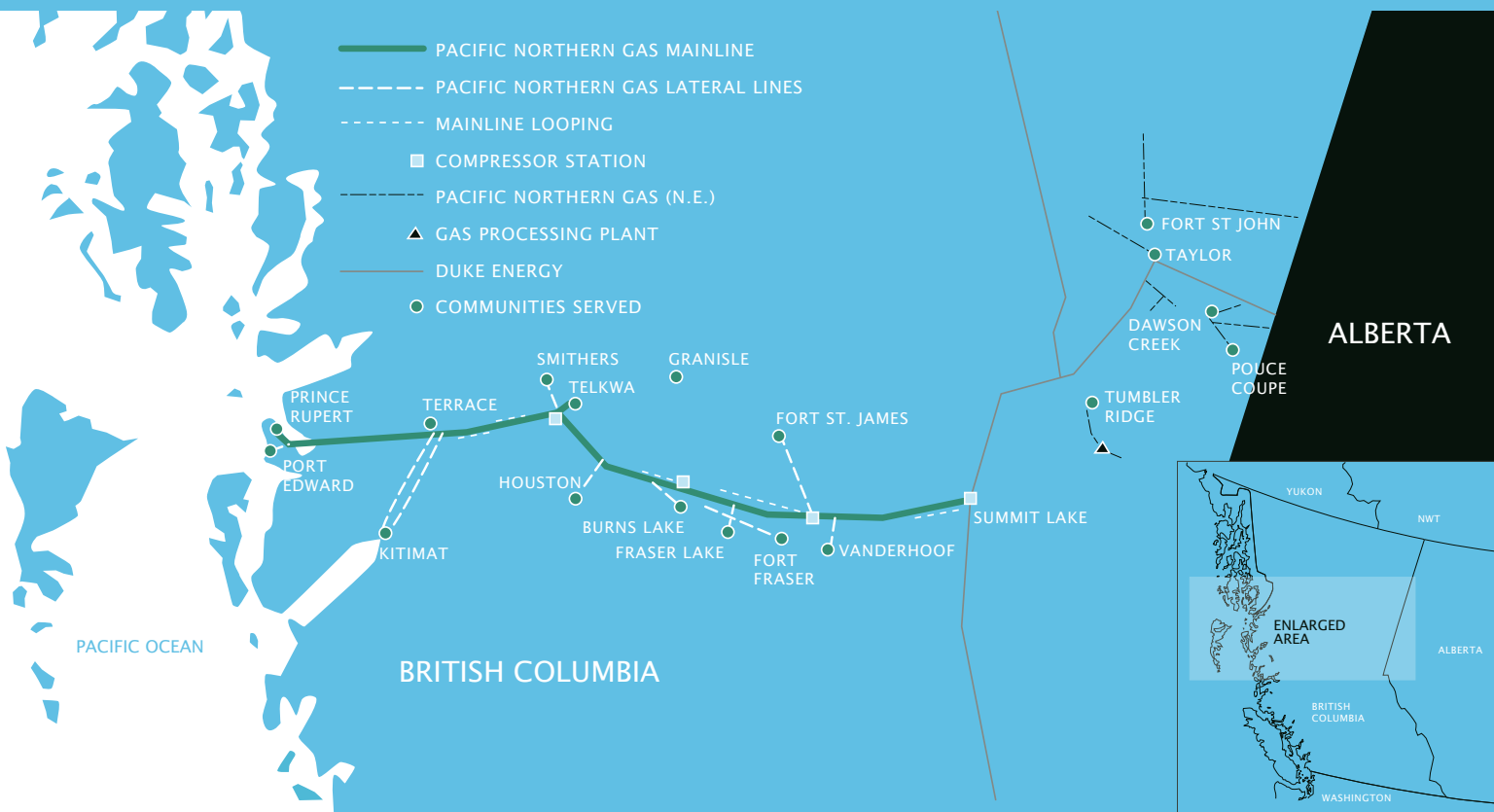
Pacific Northern's transmission pipeline is connected to the Duke Energy system near Summit Lake, British Columbia and extends 587 kilometers to the west coast.

Service is provided to approximately 23 thousand customers including a number of large industrial operations. In addition, propane vapour distribution is provided in the community of Granisle.

Pacific Northern Gas (N.E.) systems serve approximately 16 thousand customers in the Fort St. John, Dawson Creek and

Tumbler Ridge areas. Gas supply is received at a number of locations within the Fort St. John service area. In the Dawson Creek area the Company's transmission pipeline is used to transport gas from the Duke Energy system. In Tumbler Ridge the Company operates its own gas processing plant.

Pacific Northern's head office is located in Vancouver, British Columbia. Customer care and administrative functions are supported from a regional centre in Terrace. In addition, personnel responsible for customer service and system construction, operation and maintenance are stationed in nine communities located within the Company's service area.



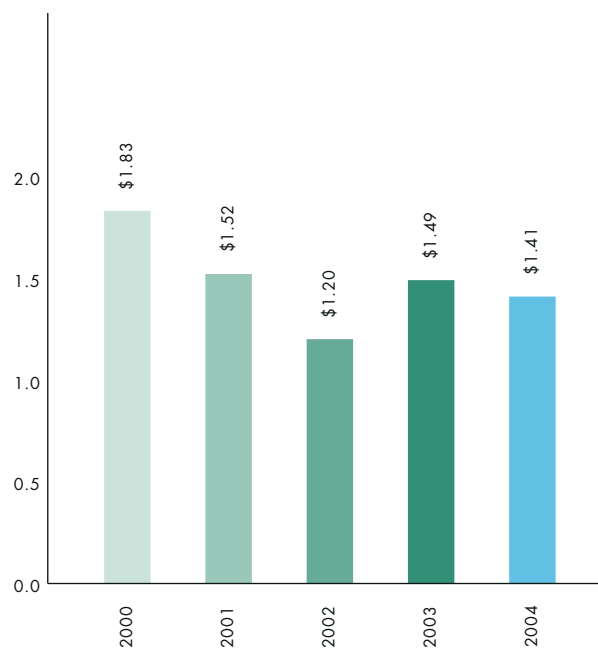
COMPARATIVE FINANCIAL HIGHLIGHTS |

	2004	2003	2002	2001	2000
Total energy delivered (TJ)	38 971	36 638	39 463	31 781	34 771
Net income (\$000)	5,408	5,668	4,590	5,715	6,838
Earnings per common share (\$)	1.41	1.49	1.20	1.52	1.83
Dividends paid per common share (\$)	0.80	3.55	0.00	0.00	0.56
Total investment in utility plant (\$000)	176,780	174,348	177,314	179,301	183,351

BUSINESS HIGHLIGHTS

- Pacific Northern's net income was \$5.4 million in 2004, compared with \$5.7 million in 2003.
- After providing for preferred share dividends, earnings per common share in 2004 were \$1.41 compared with \$1.49 in 2003.
- Common share dividends of \$0.80 were paid in 2004. Common share dividends of \$3.55 per share were paid in 2003, which included a special dividend of \$2.75 per share paid in January 2003.
- Gas deliveries during the year totalled 39.0 petajoules, compared with 36.6 petajoules in 2003.
- Additions to property, plant and equipment totalled \$11.3 million in 2004, compared with \$5.4 million in 2003. Additions to plant in 2004 include \$4.4 million for the replacement of a dual-line underwater crossing of the Salmon River on the Company's transmission system, which is expected to be in service in 2005.

EARNINGS PER COMMON SHARE



I REPORT TO SHAREHOLDERS



Pacific Northern Gas has had a challenging year in 2004 but with it came some of the biggest opportunities in the Company's history.

The Company applied to the British Columbia Utilities Commission in January 2004 to convert to an income trust ownership structure. Unfortunately, this application was denied by the Commission in July 2004. In order to pursue growth and diversification strategies, management continues to believe that it is in the best interests of all stakeholders, including shareholders, customers, lenders and employees, to convert to this type of capital structure. As such, a second application was submitted in December 2004 proposing a different regulatory framework; a public hearing on the matter is scheduled to be held in May 2005. If the second application is approved, the Company could be converted to an income fund by the end of 2005. We view this as a win-win for all parties and are focused on working through to a successful outcome.

BENEFITS OF AN INCOME TRUST STRUCTURE

Redemption of a significant portion of the Company's secured debt under an income trust structure would strengthen its credit position, and result in lower cost of debt, better access to debt capital, broader potential sources of debt financing and a greater ability to absorb volatility in both costs and revenues. Improved access to capital markets, both short term and long term, could result in lower rates for both the Company and its ratepayers and improve its ability to finance capital expenditures for ongoing maintenance, pipeline reinforcement, system growth and diversification.

2004 FINANCIAL PERFORMANCE

Net income in 2004 deteriorated slightly to \$5.4 million compared to \$5.7 million in 2003. Net income in 2004 was negatively affected by \$0.7 million in losses in unaccounted gas used in operations. We will continue to investigate the causes of the gas losses with the view to reclaim these amounts in the future.

NATURAL GAS SUPPLY & MARKET CONDITIONS

Gas commodity prices continued to be extremely volatile in 2004. Gas commodity prices reached historically high levels in October and November before trending downward in December and January 2005.

The Company prepared a hedging program in mid year that was implemented over the August to November period. As with the same time period last year, the Company considered it was prudent to fix prices for the majority of its gas supply for the 2004/2005 winter period. This strategy was again successful in managing gas price volatility over the winter.

Unfortunately, the economy continues to remain weak in the Western system area resulting in lower gas consumption by many of our customers. In contrast, the economy in the Northeast service area continues to rise due to the strength of the oil and gas exploration sector, which is reflected in further customer additions.

REPORT TO SHAREHOLDERS I

MAJOR CAPITAL EXPENDITURE

In 2004, the Company spent \$4.4 million to directionally drill under the Salmon River to replace a dual underwater transmission system crossing. This expenditure is part of a proactive maintenance plan to mitigate the risk of system failure in the event of flooding. The new crossing is expected to be in service in mid 2005.

NEW CUSTOMER AGREEMENT

In February 2004, the Company signed a memorandum of agreement with West Fraser for a new 10-year transportation contract, commencing January 1, 2004. The contract provides for a toll that is approximately 30 percent lower than the toll previously in effect and was approved by the Commission in July 2004.

NEW SHORT TERM LENDER

In January 2005, the Company arranged new credit facilities, including a \$20 million operating line and a \$15 million risk management facility. This new operating line will provide additional flexibility in financing as well as future gas hedging programs.

OUTLOOK

A number of opportunities exist in the Company's west central service area. There are two proposed liquid natural gas ("LNG") projects being considered in both Kitimat and Prince Rupert. Full development of either of these projects would have a significant positive impact on the economic growth of the region. In addition, long term natural gas development prospects are encouraging in both the Bowser and Nechako Basins. A major producer has commenced exploratory drilling in the Bower Basin.

We continue to be hopeful that an agreement on the softwood lumber dispute is reached, which would benefit sawmill operators in the Company's service areas. The Company is also encouraged by efforts of the British Columbia Provincial Government to have the moratorium lifted on oil and gas exploration off the Pacific Coast; however, offshore production is still many years away.

I would like to thank the Company's Board of Directors for their support during 2004, especially in our pursuit to convert to an income trust structure. I would also like to express my gratitude to our employees for their continued commitment during a challenging year.



Roy G. Dyce
President and Chief Executive Officer

I CHAIRMAN'S MESSAGE



The Board of Pacific Northern Gas faced a challenging year due to substantial increases in securities regulations. Our efforts were focused on achieving the right balance in fulfilling our dual responsibilities of monitoring results while adding value to the Company's activities.

The Board's governance practices focused on assessing management's performance, corporate strategy, financial results, internal controls, compensation plans, risk management and environmental programs. Board practices are reviewed regularly and changes adopted as required to ensure shareholders benefit from best practices. The excellent record of attendance by the Company's directors at both Board meetings and Committee meetings demonstrates the directors' high level of commitment to fulfilling their responsibilities to shareholders.

Dealing with the complexities of increased compliance has come at a cost, not only in monetary terms but also in time commitment and focus. These new regulations have added a level of severity to financial reviews by both management and the Board, making the process longer and more burdensome. The upside to this process is that it intensifies the focus of company insiders on governance matters; the downside is that it requires more of our directors' time who otherwise could have devoted more time to adding value to the activities of management. We look ahead optimistically to how we can achieve a better balance in the coming year.

The Canadian corporate governance environment will continue to evolve. Likewise, the Board of Pacific Northern Gas will continue to strive to achieve a model level of governance, and ensure that the Company maintains a culture of the highest ethical and professional standards. The full details of the Company's governance practices, as they compare to the guidelines issued by the Toronto Stock Exchange, are found in the Statement of Corporate Governance following this report.

A handwritten signature in black ink, appearing to read "R. Chase". The signature is fluid and cursive, with a large initial "R" and a long, sweeping underline.

Robert F. Chase

Chair of the Board

February 27, 2005

The Toronto Stock Exchange (“TSX”) requires that the Company disclose annually the corporate governance practices of its Board of Directors (“Board”). Through its Corporate Governance Committee, the Board administers a program to develop and sustain suitable and effective processes and structures to guide the direction and management of the business and affairs of the Company in the pursuit of enhanced corporate performance and shareholder value. The following report addresses how the Company fulfills the principal responsibilities of a board of directors contained in the guidelines for corporate governance established by the TSX. The Company considers itself to be in compliance with the guidelines.

The Company does not have a significant shareholder. “Significant shareholder” is defined by the TSX as a shareholder with the ability to elect a majority of the Board. Tricor Acquisition (STP) Inc. (“Tricor”) holds approximately 37 percent of the common shares of the Company and does not have the ability to elect a majority of the Board.

01 STEWARDSHIP OF THE COMPANY

The board of directors of every corporation should explicitly assume responsibility for the stewardship of the corporation and, as part of the overall stewardship responsibility, should assume responsibility for the following matters:

The Board, as set out in its terms of reference, has the responsibility for overseeing the conduct of the business of the Company and the activities of management in carrying out its responsibility for the day-to-day operations of the business. The Board’s fundamental objectives are to enhance and preserve long term shareholder value and to ensure the Company meets its obligations on an ongoing basis in an efficient and reliable manner. The Board approves all significant decisions affecting the Company and reviews the results of such decisions.

The Board operates by seeking the advice of and delegating powers, duties and responsibilities to committees of the Board, by delegating certain of its authorities to management and by reserving certain powers to itself. Members of the management team report to the Board and its committees on a regular basis to review the Company’s financial and operational results and the Company’s progress in fulfilling its strategic goals and objectives.

In addition to those matters which must by law be approved by the Board, the Board retains the responsibility for managing its own affairs including selecting its Chair, nominating candidates for election to the Board, constituting committees of the Board and determining director compensation. The Company has adopted a Code of Business Ethics that has been communicated to all employees and is maintained on the Company’s website at www.png.ca.

1A. Strategic Planning Process

The Board ensures that goals and a strategic planning process are in place for the Company and that systems have been developed to monitor and manage the principal risks and returns associated with the Company’s business activities. The Board discusses and reviews all materials related to the Company’s strategic plan with management, and is responsible for approving the strategic plan. The Board works with management to develop an appropriate planning cycle and strategic objectives, based on the circumstances faced by the Company. The Board receives regular updates from management on the Company’s progress in meeting its strategic objectives.

I CORPORATE GOVERNANCE REPORT

1B. Principal Risks

The Board, either directly or through the Audit Committee, is responsible for identifying and reviewing the Company's principal business risks, ensuring that the systems in place are effective to manage those risks and developing policies for risk management. The Audit Committee meets quarterly to review financial reports and discuss significant risk areas with the external auditors and management.

1C. Succession Planning

The Board, through the Human Resources and Compensation Committee, is responsible for succession planning, performance evaluation and setting compensation for the President and Chief Executive Officer (the "President"). The President advises the Committee on issues relating to succession planning and performance for the senior management team. The President also advises and seeks guidance from the Committee on matters relating to the development and training of senior management personnel.

1D. Communications Policy

The Board approves all of the Company's major communications, including the financial statements and management's discussion and analysis in the annual and quarterly reports, earnings releases, the annual information form and the management proxy calculator. The Company has adopted a disclosure policy that establishes procedures to provide the public with broad disclosure on a timely basis of material information concerning the affairs of the Company and communications with analysts. The Company's practices encourage the free flow of accurate and appropriate communication and, at the same time, discourage selective disclosure of material information that has not been publicly disclosed.

The Company maintains an active shareholder relations program. The program is designed to ensure that shareholder inquiries receive a prompt response from an appropriate officer of the Company. Information about the Company is also available on the Company's website at www.png.ca. The website is updated regularly and permits access to interim and annual reports, press releases and other information about the Company.

1E. Integrity of Internal Control

The Board, through the Audit Committee, is responsible for ensuring that the Company's management has designed and implemented an effective system of internal controls and for reviewing and reporting on the integrity of the consolidated financial statements of the Company. This Committee also receives any recommendations from the external auditors and management on internal controls.

02 BOARD INDEPENDENCE

A majority of the directors should be "unrelated".

The Board reviews the relationships of the directors with the Company to determine whether they are related or unrelated. In making this determination, the Board polls each director as to the nature and extent of his relationship with the Company

CORPORATE GOVERNANCE REPORT |

and considers any other information brought forward by management. The Board is composed of eight directors, one of whom, the President, is a full-time officer of the Company. The Board has determined that the rest of the directors are unrelated. The Company does not have a significant shareholder. In addition, no member of management sits on any of the Board Committees.

03 INDIVIDUAL UNRELATED DIRECTORS

The board has responsibility for applying the definition of “unrelated” director to each individual director and for disclosing annually the analysis of the application of the principles supporting this definition and whether the board has a majority of unrelated directors.

The President is an inside director. The remaining directors do not have interests in or relationships with the Company (other than interests and relationships arising from share holdings), which could, or could reasonably be perceived to materially interfere with such directors’ ability to act with a view to the best interests of the Company. The Board has concluded that seven of the eight directors of the Company are unrelated.

04 NOMINATING COMMITTEE

The board should appoint a committee of directors composed exclusively of outside (i.e. non-management) directors, a majority of whom are “unrelated” directors, with responsibility for proposing new nominees to the board and for assessing directors on an ongoing basis.

The Company does not have a nominating committee. The Corporate Governance Committee, which has primary responsibility for the search for and recommendation of candidates for election to the Board, seeks to select well-qualified candidates with a diversity of background, experience and geographic location to maintain a well-balanced and highly competent group of directors with the ability to act together effectively. This Committee is also responsible for the ongoing assessment of directors. All members of the Corporate Governance Committee are unrelated.

05 ASSESSING THE BOARD’S EFFECTIVENESS

The board should implement a process to be carried out by the nominating committee or other appropriate committee for assessing the effectiveness of the board as a whole, the committees of the board and the contribution of individual directors.

Through the auspices of the Corporate Governance Committee, an assessment of the overall effectiveness of the Board and the Chair is conducted annually. The Chair reviews the activities of the Board and the Committees over the prior year,

I CORPORATE GOVERNANCE REPORT

including the attendance record of each Board member, and discusses pertinent issues with each Board member as deemed appropriate. This assessment is tabled and reviewed by the Corporate Governance Committee.

The Board met seven times in 2004, with 96 percent attendance by directors.

06 ORIENTATION AND EDUCATION OF DIRECTORS

The Company should provide an orientation and education program for new recruits to the board.

All new directors receive a Board manual containing public information about the Company, as well as the terms of reference and timetables for the Board and the committees and other relevant corporate and business information. The senior management team makes regular presentations to the Board on matters with significant impact on the Company's business.

07 EFFECTIVE BOARD SIZE

The board should examine its size and, with a view to determining the impact of the number upon effectiveness, undertake where appropriate a program to reduce the number of directors to a number which facilitates more effective decision-making.

The Board regularly reviews its composition and size to ensure that the Company is in compliance with applicable legislative requirements and that the composition and size of the Board fairly reflects the interests of all shareholders. In 2003, the size of the Board was increased by one director, to a total of eight. The current composition and size of the Board is considered appropriate to permit the directors to efficiently and effectively fulfil their fiduciary obligations.

08 COMPENSATION OF DIRECTORS

The board of directors should review the adequacy and form of the compensation of directors and ensure the compensation realistically reflects the responsibilities and risk involved in being an effective director.

Directors are compensated through annual retainer fees and a fee per meeting attended, as well as reimbursement for expenses. The Board, through the Human Resources and Compensation Committee, is responsible for periodically reviewing the adequacy and form of compensation of directors and for ensuring that the compensation realistically reflects the responsibilities and risks involved in being an effective director of the Company and for reporting and making recommendations to the Board accordingly. Periodically outside advisors are engaged to review the adequacy of directors' compensation, with the last review conducted in 2002.

CORPORATE GOVERNANCE REPORT |

09 COMMITTEES AND OUTSIDE DIRECTORS

Committees of the board of directors should generally be composed of outside directors, a majority of whom are unrelated directors, although some board committees (such as the executive committee) may include one or more inside directors.

The Board has established and adopted terms of reference and annual timetables for five committees:

- Audit Committee
- Executive Committee
- Environment, Health and Safety Committee
- Human Resources and Compensation Committee
- Corporate Governance Committee

All committees are composed entirely of outside and unrelated directors. See #13 for a discussion of the role of the Audit Committee.

The Executive Committee is composed of three directors and is narrowly mandated to act as the approving body for expenditures which have been broadly approved by the Board and which are beyond the approval levels of the President and to perform such functions and exercise such powers as are specifically delegated to the committee by the Board. This Committee met three times in 2004, with 89 percent attendance by committee members.

The Environment, Health and Safety Committee is composed of three directors, and is responsible for reviewing and monitoring the policies and activities of the Company relating to environment, health and safety matters on behalf of the Board. This Committee met twice in 2004, with full attendance by all members for each meeting.

The Human Resources and Compensation Committee is composed of three directors, and is generally responsible for recommending to the Board human resources and compensation policies and guidelines for application to the Company and for implementing and overseeing human resources and compensation policies approved by the Board. This Committee met twice in 2004, with full attendance by all members for each meeting.

The Corporate Governance Committee is composed of three directors. Through the Corporate Governance Committee, the Board develops and monitors sound corporate governance practices to enhance corporate performance. This Committee has responsibility for proposing new members to the Board, establishing criteria for Board membership, recommending composition of the Board and its committees, assessing directors' and Board performance on an ongoing basis and ensuring an orientation and education program is in place for new members of the Board. This Committee met twice in 2004, with 83 percent attendance by Committee members.

Special Committees of the Board are struck from time to time to deal with matters of significance before the Company.

I CORPORATE GOVERNANCE REPORT

10 APPROACH TO CORPORATE GOVERNANCE

Every board of directors should expressly assume responsibility for, or assign to a committee of directors, the general responsibility for developing the corporation's approach to governance issues. This committee would be responsible for the corporation's response to these governance guidelines.

The prime responsibility of the Corporate Governance Committee is to develop and monitor the Company's overall approach to corporate governance issues and to administer a corporate governance system which is effective in the discharge of the Company's obligations to its stakeholders, including providing timely, accurate and fulsome disclosure. The Corporate Governance Committee has responsibility for reviewing and approving the Company's Statement of Corporate Governance. Management, the external auditors and legal counsel provide the Board with updates on governance initiatives by regulators as well as best practises recommendations on a regular basis.

11 POSITION DESCRIPTIONS

The board of directors, together with the Chief Executive Officer, should develop position descriptions for the board and for the Chief Executive Officer, involving the definition of the limits to management's responsibilities. In addition, the board should approve or develop the corporate objectives which the Chief Executive Officer is responsible for meeting.

Terms of reference for the Board and position descriptions for the Chair and the President have been approved by the Board.

The goals and objectives for the President are drafted by the President and reviewed and discussed with the Human Resources and Compensation Committee prior to being presented to the full Board for acceptance.

The Board primarily expects management to review the Company's strategies and their implementation, carry out a comprehensive budgeting process and monitor financial performance against the budget, and identify opportunities and risks affecting the Company's business and develop strategies to address those challenges.

12 BOARD INDEPENDENCE

The board should implement structures and procedures which ensure that it can function independently of management.

The Board acts independently of management either directly or through committees of the Board which are delegated some of the Board's responsibilities. The Chair of the Board is an unrelated director. At each meeting of the directors, the outside directors meet in-camera without members of management present.

CORPORATE GOVERNANCE REPORT |

13 AUDIT COMMITTEE

The audit committee should be composed of only unrelated directors. The roles and responsibilities of the audit committee should be specifically defined so as to provide appropriate guidance to audit committee members as to their duties. The audit committee should have direct communication channels with the internal and external auditors to discuss and review specific issues as appropriate.

The Audit Committee is composed entirely of unrelated directors. Two of the members are financial professionals and all members are financially literate. The Committee's responsibilities are set out in its terms of reference. Its responsibilities include ensuring compliance with regulatory and statutory requirements as they relate to financial statements, taxation matters, pension matters, the disclosure of material facts and reviewing the appropriateness and effectiveness of the Company's policies and business practices that impact on the financial integrity of the Company, including those relating to internal auditing, insurance, accounting, information services and systems and financial controls, management reporting and risk management. The Audit Committee reviews the Company's annual and interim reports and the annual information form as well as the annual audit plan and the results of the audit. At each meeting of the Audit Committee, members of the committee meet in-camera with the external auditors without management present. The Audit Committee met four times in 2004, with full attendance by all members for each meeting.

14 OUTSIDE ADVISORS

The board should implement a system to enable an individual director to engage an outside advisor at the Company's expense in appropriate circumstances. The engagement of the outside advisor should be subject to the approval of an appropriate committee of the board.

Directors and committees of the Board are permitted to hire outside advisors at the expense of the Company with the approval of the Board. Outside advisors, lawyers and financial advisors were hired in 2003 by a Special Committee of the Board to review options to enhance shareholder value. In addition, a human resources consulting firm was engaged by the Board in 2002 to review and assess director compensation.

I MANAGEMENT'S DISCUSSION AND ANALYSIS (MD&A)

DATE: FEBRUARY 28, 2005

FORWARD-LOOKING STATEMENTS

Management's discussion and analysis contains certain forward-looking statements that are subject to risks and uncertainties that may cause the results or events predicted in this discussion to differ materially from actual results or events. In addition to the risks outlined in the Risk Management section at the end of the discussion, factors which could cause the results or events to differ include, but are not limited to: general economic conditions; gas commodity price volatility; decisions by regulators; seasonal weather patterns; the cost and availability of capital; and the ability of the Company to attract and retain quality employees. No assurance can be given that results, performance or achievement expressed in, or implied by, forward-looking statements within this disclosure will occur, or if they do, that any benefits may be derived from them. The Company undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

BUSINESS OVERVIEW

Pacific Northern Gas Ltd. and its wholly-owned subsidiary Pacific Northern Gas (N.E.) Ltd. (together the "Company") are natural gas distribution utilities operating within the Province of British Columbia. The Company operates in two service areas, a transmission and distribution system in the west-central portion of northern British Columbia ("Western system") and a distribution system in northeastern British Columbia ("Northeast system"). The Northeast system is comprised of two divisions, the Fort St. John/Dawson Creek division and the Tumbler Ridge division.

The Company continues to monitor the competitiveness of its natural gas retail rates relative to alternative heating sources in its service area. Substantial increases in gas supply commodity prices over the last few years, combined with increases in the Company's delivery margins for residential, commercial and small industrial customers for its Western system, have led to retail gas rates which are similar to, or slightly higher than, the cost of electricity.

The Company's strategic focus in 2005 will be to enhance shareholder value by continuing to pursue recapitalization under an income trust ownership structure. On December 17, 2004, the Company filed an application with the British Columbia Utilities Commission (the "Commission") seeking the approvals required pursuant to the Utilities Commission Act to transfer the ownership of the Company from the current common shareholders to an income trust called the "PNG Income Trust". The PNG Income Trust would be owned by unit holders who would comprise the current shareholders that would exchange their common shares for units and new investors under an initial public offering of PNG Income Trust units. The recapitalization under an income trust ownership structure is expected to improve the Company's access to capital and improve its ability to pursue growth and diversification strategies.

The application will be reviewed at a public hearing before the Commission in May 2005. A decision by the Commission is expected to be rendered by the third quarter of 2005. Any transfer of ownership would also require the approval of the shareholders of the Company, court approval, and acceptable market conditions. The Company can give no assurances that the required approvals will be obtained, or that the conversion to an income trust ownership structure will occur.

OVERALL PERFORMANCE

Net income for 2004 was \$5.4 million, compared with \$5.7 million for 2003, or a decrease of 4.6 percent. After providing for preferred share dividends, earnings per common share for 2004 were \$1.41 compared with \$1.49 for 2003. The decrease in net income was primarily a result of higher expense for gas used in operations but not accounted for. Unaccounted for gas is the difference between the quantity of gas measured into the pipeline system and the quantity of gas delivered to customers and used in the company's operations, whether it is more or less. The impact of this unaccounted for gas loss, net of tax, was approximately \$0.7 million in 2004, compared to nil in 2003. A consultant was hired in 2004 to identify possible causes contributing to the gas loss, particularly in the Northeast system, and is conducting an extensive analysis of measurement practices.

SELECTED ANNUAL INFORMATION

The following financial information has been prepared in accordance with Canadian GAAP and is shown in Canadian dollars.

[Dollar amounts in thousands, except per share and per GJ figures]	2004	2003	2002
Deliveries (TJ) –			
Sales	7 338	7 754	8 045
Transportation service	31 633	28 884	31 418
Total	38 971	36 638	39 463
Customers at period end	39,291	39,106	39,254
Weighted average cost of gas purchased (\$ per GJ)	6.42	6.59	4.11
Operating revenues	\$ 137,755	\$ 133,727	\$ 109,063
Operating margin, consisting of operating revenues less cost of sales	48,801	49,310	52,234
Net income	5,408	5,668	4,590
Basic earnings per common share	1.41	1.49	1.20
Diluted earnings per common share	1.38	1.46	1.18
Total assets	207,657	206,414	212,506
Total long term financial liabilities	97,284	101,481	105,677
Dividends paid per common share	0.80	3.55	0
Dividends paid per preferred share	1.69	1.69	1.69

RESULTS OF OPERATIONS

Deliveries to residential and commercial customers in 2004 were lower by 0.4 petajoules, or 6 percent, compared to deliveries in 2003. Some of the reduction in deliveries was due to weather, which was approximately 5 percent warmer in 2004 than in 2003. Deliveries to residential and small commercial customers in 2004 were lower by 0.5 petajoules, or 8 percent, compared to the forecast volumes used to set customer rates. In 2003, deliveries were 6 percent lower than the forecast volumes used to set rates. The reduction in deliveries did not significantly impact net income due to the existence of a deferral account that captured the after-tax value of the revenue variance, amounting to \$1.2 million (\$0.9 million in 2003), arising from differences between actual and forecast volumes for residential and small commercial customers. Deliveries to residential and commercial customers were down 11% in 2002 compared to forecast volumes used by the Commission to set rates which resulted in a negative impact on net income of approximately \$1.9 million.

Operating revenues in 2004 increased to \$137.8 million as compared with \$133.7 million in 2003, largely due to an increase of \$10.5 million in sales of gas surplus to the needs of the Company's sales customers ("off system gas sales"). Natural gas commodity prices, which are passed through the Company's sales customers without mark-up, are very volatile and result in significant variability of the Company's reported operating revenues. Operating revenues in 2004 and 2003 were significantly higher than 2002 largely due to the higher commodity cost of gas.

Operating margin in 2004 decreased to \$48.8 million, as compared with \$49.3 million in 2003. This decrease was due to reductions in customer rates in 2004 that were based on anticipated reductions in amortization and company use gas expenses, which also caused the decrease in operating margin in 2003 compared to 2002.

NATURAL GAS DELIVERIES

Natural gas deliveries in 2004 totaled 38 971 terajoules* compared with 36 638 terajoules in 2003. A comparison of 2004 and 2003 deliveries is provided in the following table:

Deliveries in terajoules*	2004	2003	% CHANGE
SALES:			
Residential	3 279	3 464	(5.3)
Commercial	2 655	2 845	(6.7)
Small Industrial	778	825	(5.6)
Large Industrial	626	620	1.0
Total Sales	7 338	7 754	(5.4)
TRANSPORTATION SERVICE:			
Commercial	60	64	(7.4)
Small Industrial	2 958	2 764	7.0
Large Industrial	28 615	26 056	9.8
Total Transportation Service	31 633	28 884	9.5
Total Deliveries	38 971	36 638	6.4

* The joule is a metric energy measurement unit. One gigajoule (GJ) is equivalent to 0.94782 British thermal units (BTU). One terajoule (TJ) equals one thousand GJ. One petajoule (PJ) equals one million GJ. In volumetric units, 1000 cubic meters is equivalent to 35.301 thousand cubic feet.

Transportation deliveries to large industrial customers increased 9.8 percent from 2003 to 2004 resulting from operations returning to normal in 2004 for the Company's two largest customers after a four-month labour dispute at West Fraser Mills Ltd.'s Kitimat pulp mill ("West Fraser") and a five-week maintenance shutdown at the Kitimat methanol/ammonia facility of Methanex Corporation ("Methanex"), both in 2003.

CUSTOMER ADDITIONS

In 2004, 345 new services were connected to the Company's distribution systems, compared with 284 in 2003. This increase in service additions is the result of continued strong economic activity in the Northeast system. Although 345 new services were connected, the Company experienced a net increase of only 185 customers. This is a result of 160 customers leaving the distribution system, primarily in the Company's Western service area. The continued net loss of customers in the Western service area reflects the generally poor economic conditions in this area.

In mid 2001, the Company implemented a modified main extension and service connection policy. These changes require new customers to fully cover the cost of service line connections to the distribution system. Also, in situations where main extensions are required, initial customers must fund the full amount of any shortfall between the Company's allowable investment and total estimated construction costs. This has eliminated the Company's role in financing a portion of main extension costs until all anticipated customers are connected to a new main.

There are few remaining candidates for conversion to natural gas in the existing building stock and limited opportunity remains to extend gas mains into unserved rural areas in the Western service area.

NATURAL GAS SUPPLY

All of the Company's residential customers, most of its commercial customers and a number of its small industrial customers purchase gas from the Company at rates which include the gas commodity cost and the Company's cost of delivering gas to the customers' premises. The gas commodity cost paid by the Company to its gas suppliers is passed through without mark-up to customers.

The Commission reviews the gas commodity portion of the Company's rates on a quarterly basis to ensure close alignment with the prevailing market prices for natural gas. Any variances in gas commodity prices paid by the Company from those included in current retail rates are deferred for subsequent refund to or recovery from customers. To moderate the variability of the gas supply commodity prices paid, the Company uses financial instruments under a gas price management plan that is filed with the Commission on an annual basis.

A gas supply contracting plan is also prepared annually and filed with the Commission for review prior to finalizing annual gas purchase arrangements. The Company purchases gas from gas producers under long term and short term gas purchase contracts. The gas contracting plan is designed to ensure the Company has adequate gas supplies at reasonable prices to meet the requirements of its customers on the coldest day of the year, normally referred to as "the peak day". Contracted gas that is surplus to customer requirements is then sold into other markets at prevailing market prices. Most of the Company's contracted gas supply is produced in British Columbia.

The Company's large industrial customers, the majority of its small industrial customers and a few large commercial customers arrange for delivery of their gas supply requirements to the Company. These customers, contract for gas transportation service on the Company's pipeline systems. Some of these customers also purchase gas from the Company to supplement their gas supply as may be required from time to time and subject to gas supply availability from the Company.

For 2004, approximately 34 percent of gas purchases were hedged pursuant to the Company's gas price management plan (for further information as of December 31, 2004 with regard to 2005 gas supply, see Financial Instruments and Other Instruments on page 28).

Virtually all of the Company's gas supply is composed of the pooled gas stream available from the Duke Energy Gas Transmission ("Duke Energy") pipeline system. This includes all of the supply to the Company's transmission line serving its Western service area and approximately 73 percent of the supply for the Fort St. John and Dawson Creek service areas. In addition to the supply from the Duke Energy system, the Fort St. John system incorporates two interconnections with Canadian Natural Resources Limited's West Stoddart Pipeline, providing 38 percent of the Fort St. John system's requirements. In Dawson Creek, approximately 8 percent of the required supply is received from a local producer of sweet (pipeline quality) gas at a point where its system intersects the Company's transmission line. In Tumbler Ridge, all of the gas supply is obtained in the form of raw gas production from a local producer and the Company operates its own gas processing facilities.

A long term contract with CanWest Gas Supply Inc. accounted for about 61 percent of 2004 purchases. Other supplies included purchases under seasonal and spot gas supply arrangements.

LARGE INDUSTRIAL CUSTOMERS

The Company has firm transportation service and interruptible sales/service agreements with three of its large industrial customers: Methanex, West Fraser and Alcan Smelters and Chemicals Ltd. ("Alcan").

The Company delivers gas to its other large industrial customer, British Columbia Hydro and Power Authority ("BC Hydro"), under an interruptible sales/service agreement for emergency electric power generation at BC Hydro's facility in Prince Rupert.

The large industrial customers produce commodities that are subject to world commodity price fluctuations. The Company's gas deliveries to these customers have been and may in the future be affected by their ability to continue operation during sustained periods of low commodity prices.

Deliveries to Methanex in 2004 accounted for approximately 67 percent of volumes delivered by the Company and approximately 9 percent of the Company's operating revenues. Transportation service to Methanex in 2004 was provided pursuant to an agreement that expires October 31, 2009. An annual demand charge based on a firm toll of 50 cents per gigajoule applies over the term of the agreement. In addition, under the contract, Methanex supplies a portion of the Company's internal gas requirements equal to four percent of deliveries to Methanex. The contract also includes a profit-sharing mechanism during periods of high methanol prices and relatively low natural gas prices. The profit-sharing mechanism did not result in any additional revenue to the Company in 2004.

The transportation service and sales contracts with West Fraser and Alcan are in effect through December 31, 2013 and October 31, 2006, respectively. The agreement with Alcan will continue to be in effect beyond October 31, 2006 unless Alcan or the Company gives notice of termination. During 2004, deliveries to West Fraser and Alcan accounted for 6 and 3 percent, respectively, of the Company's total gas deliveries and 2 and 4 percent, respectively, of operating revenues.

REGULATORY ACTIVITIES

The Company is subject to regulation under the Utilities Commission Act of British Columbia. The Commission regulates the business of the Company, including the construction and operation of major facilities, the issuance of securities, the determination of rates for the sale and transportation of gas and the terms and conditions of service.

In approving rates, the Commission must determine that the rates reflect a fair and reasonable charge for the nature and quality of service provided to customers. The rates should be sufficient to enable the Company to earn a fair and reasonable compensation for its services and a fair and reasonable return upon the value of its property.

The Commission determines customer rates using a fixed rate approach on the basis of forecasts of both the cost of service and the volumes of gas delivered through the transmission and distribution systems. The cost of service consists of the cost of purchased gas and the cost of transporting all gas delivered, including operating, maintenance and administrative expenses, depreciation of facilities, income and other taxes and a return on rate base. Rate base is the sum of the depreciated cost of property, plant and equipment that is used or useful in serving the Company's customers, plus a reasonable allowance for working capital, less deferred income taxes. The Commission determines the allowable return on rate base after considering a variety of factors, including the degree of risk associated with the Company's business and the cost of capital.

Revenue requirements applications for all service areas are submitted to the Commission, generally on an annual basis. The Commission may consider these applications through a public hearing process (either oral or written), or through negotiations with the customers under alternate dispute resolution processes supervised by Commission staff.

In November 2003, the Company filed applications with the Commission for approval of new rates to take effect January 1, 2004 for all service areas. The revenue requirement applications for 2004 were considered by the Commission through a public hearing process for the Western system and a written hearing process for the Fort St. John/Dawson Creek and Tumbler Ridge divisions.

On January 30, 2004, the Company filed an application with the Commission seeking the approvals required pursuant to the Utilities Commission Act to transfer the ownership of the Company from the current common shareholders to an income trust. The PNG Income Trust unit holders were expected to comprise current shareholders who would exchange their common shares for units as well as new investors via an initial public offering of PNG Income Trust units. The Commission reviewed the application through a public hearing process during April 2004.

The Commission issued its decision on the Company's 2004 revenue requirements application on July 29, 2004 for the Western system. The 2004 allowed rate of return on common equity was 9.80 percent, based on a deemed common equity component of 36 percent. The allowed rate of return on common equity includes a 65 basis point premium over the low risk benchmark utility rate of return.

The Commission issued its decisions on the 2004 revenue requirements applications on July 29, 2004 for the Fort St. John/Dawson Creek and Tumbler Ridge divisions. The 2004 allowed rate of return on common equity was 9.55 percent for the Fort St. John/Dawson Creek division and 9.80 percent for the Tumbler Ridge division, based on a deemed common equity component of rate base of 36 percent. The allowed rate of return on common equity includes a 40 basis point premium over the low risk benchmark utility rate of return (65 basis point premium for the Tumbler Ridge division).

The Commission's decision on the Company's application to transfer ownership of the Company to an income trust was also issued on July 29, 2004. Under the decision, the Commission denied the application, citing concerns over the requirement to deem a common equity component higher than the Company's actual level of equity, as well as requirements to deem income tax expenses for rate making purposes. The Company filed a new application to convert to an income trust ownership structure in mid December 2004. The new application addresses the concerns raised by the Commission in its earlier decision. In particular, the new application requests that the Commission set customer rates using the Company's actual income trust capital structure rather than a deemed capital structure. An oral public hearing on the application is scheduled to commence in Vancouver on May 10, 2005.

WESTERN SYSTEM

For 2004, the Commission continued its direction to defer the difference between actual operating margin from deliveries to Methanex, West Fraser, Alcan and B.C. Hydro and the forecast operating margin used by the Company in its revenue requirement application in an Industrial Customers Deliveries Deferral Account ("ICDDA"). The ICDDA reduced 2004 net earnings by \$0.2 million as a result of actual 2004 deliveries to these customers exceeding forecast amounts. The Commission also accepted the Company's forecast of gas supply costs for 2004. Rate riders were approved in various amounts for 2004 to refund a credit balance accumulated in the gas purchase variance payable account. In 2004, the reduction in customer revenue from credit rate riders totalled \$1.6 million, and was applied, on an after tax basis, to reduce the gas purchase variance payable account.

In 2004, the net book value of a propane air plant which is no longer in service and has an undepreciated value of \$966,000 was removed from fixed assets and transferred to a deferral account for proposed future recovery from customers over a period of twenty years commencing in 2005. The ultimate realization of these deferred charges is subject to a future decision of the Commission.

The 2005 revenue requirements application for the Western system was filed with the Commission in December 2004. The application sought approval of increased delivery charges and increased gas supply commodity charges, effective January 1, 2005. Approximately two-thirds of the gas delivery charge increase was due to the Company seeking approval for the Western system of an increase in common equity from the deemed 36 percent approved by the Commission in 2004 to the Company's actual common equity of approximately 51 percent for the Western system. The Commission approved interim gas delivery charge increases effective January 1, 2005 applying the existing deemed 36 percent common equity ratio. The permanent gas delivery rates will be determined under a review process to be conducted after the Commission releases its decision on the Company's new application to convert to an income trust ownership structure.

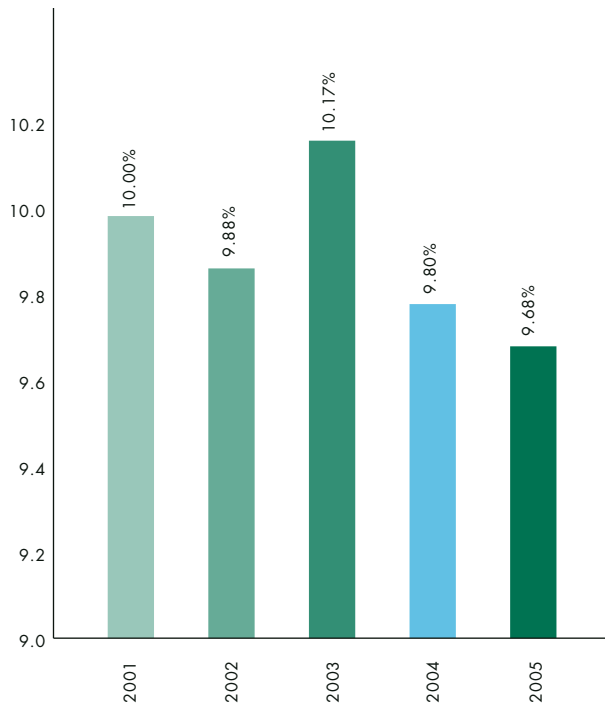
I MD&A

The Commission accepted the gas supply commodity charge increases applied for by the Company, effective January 1, 2005. The permanent gas supply commodity charges are approximately 10 percent higher than what was embedded in rates effective December 31, 2004.

The forecast 2005 residential and commercial deliveries contained in the 2005 revenue requirements application for the Western system are approximately six percent higher than actual gas deliveries to these customer classes in 2004. Deliveries to small industrial customers are projected to be approximately nine percent lower in 2005 compared to actual gas deliveries in 2004.

In December 2004, the Commission confirmed that its formula for determining the allowable return on common equity in 2005 resulted in a 9.03 percent return for a low risk benchmark utility for the year. For the Company, a return on equity risk premium of 65 basis points applies to the Western system resulting in an allowable return on common equity of 9.68 percent for 2005.

PNG WEST ALLOWED RETURN ON COMMON EQUITY 2001-2005



FORT ST. JOHN / DAWSON CREEK DIVISION

The Commission accepted the Company's forecast of gas supply costs for 2004. Rate riders were approved for 2004 to refund credit balances recorded in the gas purchase variance recoverable account at December 31, 2003 over a period of three years. In 2004, customer revenue from rate riders totalled \$0.2 million, which was applied, on an after tax basis, to reduce the gas purchase variance recoverable account.

The Fort St. John/Dawson Creek 2005 revenue requirements application, filed in December 2004, sought Commission approval to increase both the gas delivery charge component of its gas rates as well as the gas commodity charges. The Commission approved interim delivery charges effective January 1, 2005 at the level applied for which includes a deemed common equity of 36 percent and an allowable return on common equity of 9.43 percent for 2005. The gas supply commodity charge increases were approved as filed on a permanent basis. In total, the rate increases effective January 1, 2005 are higher by approximately five and four percent for residential and small commercial customers, respectively, compared to rates in effect as of December 31, 2004.

TUMBLER RIDGE DIVISION

The Tumbler Ridge 2005 revenue requirement application was filed with the Commission in December 2004. The application sought Commission approval to increase the gas delivery charge component of rates effective January 1, 2005 and no changes in the gas commodity charge component of rates. The requested increases in the gas delivery charge component are primarily due to increased operating costs, including increases in the cost of gas required for operating the Company's processing plant. The resulting rate increases were approximately three percent for residential and small commercial customers relative to rates in effect on December 31, 2004.

The Commission is conducting a written hearing process for the Fort St. John/Dawson Creek and Tumbler Ridge divisions' 2005 revenue requirements applications and a decision by the Commission is expected in the second quarter of 2005.

SUMMARY OF QUARTERLY RESULTS

The following financial information has been prepared in accordance with Canadian GAAP and is shown in Canadian dollars.

	2004				
	MAR. 31	JUNE 30	SEPT. 30	DEC. 31	TOTAL
Operating revenues	43,584	28,245	25,169	40,757	137,755
Net income (loss)	3,848	317	(1,427)	2,670	5,408
Earnings (loss) per common share – basic	1.05	0.06	(0.42)	0.72	1.41
Earnings (loss) per common share – diluted	1.03	0.06	(0.42)	0.71	1.38

	2003				
	MAR. 31	JUNE 30	SEPT. 30	DEC. 31	TOTAL
Operating revenues	41,683	28,571	24,025	39,448	133,727
Net income (loss)	3,679	47	(723)	2,665	5,668
Earnings (loss) per common share – basic	1.01	(0.01)	(0.22)	0.72	1.49
Earnings (loss) per common share – diluted	0.99	(0.01)	(0.22)	0.70	1.46

I MD&A

The Company's natural gas distribution business is very seasonal, with higher sales in the colder winter months and lower sales in warmer months as a result of a substantial portion of its gas sales being used for space heating purposes. As a result, the Company earns the majority of its net income in the first and fourth quarters of its fiscal year and often realizes losses in the other quarters.

LIQUIDITY

CONTRACTUAL OBLIGATIONS

PAYMENTS DUE BY PERIOD AS OF DECEMBER 31, 2004					
Thousands of dollars	Total	Less than 1 year	1 - 3 years	4 - 5 years	After 5 years
Long Term Debt	\$ 85,829	\$ 4,382	\$ 9,764	\$ 9,762	\$ 61,921
Purchase Obligations	42,714	41,678	1,036	—	—
Total	\$ 128,543	\$ 46,060	\$ 10,800	\$ 9,762	\$ 61,921

The purchase obligations in the table above represent commitments by the Company to purchase natural gas from its suppliers. The Company enters into a number of arrangements to purchase gas on a seasonal basis for resale to its customers during the heating season.

FUNDING REQUIREMENTS

The Company's capital expenditures, working capital needs, dividend payments and debt repayments are funded from a combination of sources. During 2004, the primary sources of funding were \$16.4 million of cash generated from operations, a drawdown of \$0.3 million of cash balances, and a draw of \$3.1 million in demand loans under an operating line of credit.

The Company purchases gas for resale to its core market customers and passes through the commodity cost of gas to those customers without mark-up. The rates charged to core market customers are based, in part, on projected gas supply prices. The Company's liquidity requirements are affected by delays between increases or decreases in the cost of gas purchased by the Company and regulatory approval of rate adjustments to reflect the cost increases or decreases.

FINANCIAL RATIOS

At the end of 2004, interest coverage using earnings before interest, income taxes, depreciation, and amortization was 3.26 times compared to 3.34 times in the prior year, declining mainly as a result of lower earnings, offset by a reduction in interest expense.

FUNDING COSTS

INTEREST EXPENSE

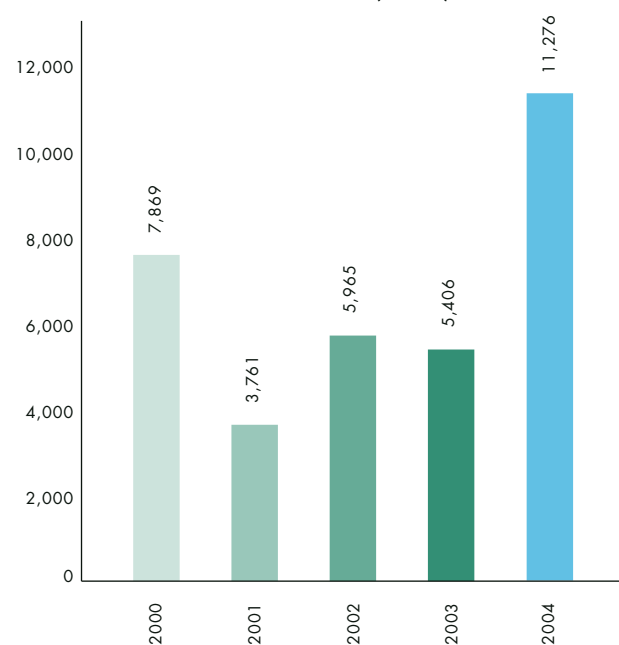
[Dollar amounts in thousands, except percent figures]	2004	2003
Long term interest expense	\$ 7,564	\$ 7,536
Short term interest expense	450	573
Total	\$ 8,014	\$ 8,109
Effective blended cost of debt (%)	9.0	8.7

The slight increase in the effective blended cost of debt is due to a more rapid amortization of the lower rate variable interest debentures, compared to the fixed rate debentures.

CAPITAL EXPENDITURES

Total capital expenditures in 2004 were \$11.3 million or \$6.0 million higher than those incurred in 2003 and 71 percent above the average level of expenditures for the last five years. However, \$4.4 million of the capital expenditures in 2004 were out of the ordinary resulting from a requirement to directionally drill under the Salmon River to replace a dual underwater transmission system crossing. The balance of the capital expenditures were for maintenance capital as well as customer additions to the distribution system on the Northeast system.

CAPITAL EXPENDITURES 2000-2004 (\$000s)



I MD&A

CAPITAL EXPENDITURES

[Dollar amounts in thousands]	2004	2003
Transmission system	\$ 7,032	\$ 2,310
Distribution system	2,905	2,356
Processing plant	80	41
Other	1,259	699
Total	11,276	5,406

Planned capital spending in 2005 is primarily directed toward distribution mains and services as well as transmission mainline rehabilitation, and is forecast to be approximately \$7.3 million. Contractual commitments have yet to be made for major planned capital expenditures for 2005. These capital expenditures will be funded from cash flow from operations.

CAPITAL RESOURCES

COMPOSITION OF CAPITAL STRUCTURE (PERCENT)

At December 31	2004	2003
Preferred shareholders' equity	2.9	2.9
Common shareholders' equity	43.3	42.2
Short term debt	3.5	1.7
Long term debt, including current portion	50.3	53.2
	100.0	100.0

For rate determination purposes the Company is permitted to earn a return on its invested capital to the extent of its approved rate base. Rate base is composed of the depreciated book value of fixed assets, plus unamortized deferred charges, plus an allowance for working capital, less deferred income taxes. The Commission sets customer rates at a level that is intended to allow the Company to earn its allowed rate of return on common equity on 36 percent of rate base. The 36 percent is significantly below the 43 percent common equity on the Company's balance sheet, and below the requested increase to 51 percent for common equity in the 2005 rate application for the Western system.

EQUITY

The book value of the common shares at December 31, 2004 was \$20.52 per share, compared to \$19.96 per share at December 31, 2003.

The Company's preferred shares are currently rated Pfd-3(low) by Dominion Bond Rating Service ("DBRS").

DIVIDENDS

Preferred dividends totaling \$1.6875 per share were paid in 2004, the same as in 2003.

Common dividends totaling \$0.80 per share were paid in 2004, compared to \$3.55 per share in 2003. The 2003 dividends included a special dividend of \$2.75 per common share paid in January 2003. The special dividend was declared following the issuance of \$15 million of new long term financing in December 2002, and resulted in a capital structure that was more closely aligned with that approved by the Commission.

A total of \$3.2 million preferred and common dividends were paid in 2004, compared to \$13.1 million paid in 2003.

SHORT TERM DEBT

Throughout 2004 the Company had a bank demand operating and hedge line of credit of \$25 million that bore interest at prime rate or bankers' acceptance rates and provided funds for general corporate and working capital requirements. The amount available under this facility was subject to borrowing base requirements. The line of credit was collateralized by the pledge of a \$25 million debenture and a charge on certain accounts receivable and inventories.

As a result of seasonality in operations, marginable receivables and other assets are significantly reduced in the second and third quarters compared to the winter heating season, thus constraining availability of the demand line of credit. At December 31, 2004, the amount available under the facility was approximately \$6.4 million, of which \$6.1 million had been drawn. The Company provided covenants to its operating lender, all of which were complied with during 2004.

In January 2005, the Company arranged new credit facilities which include a \$20 million operating line and a \$15 million risk management facility. The operating line is subject to borrowing base requirements and financial covenants which may act to restrict the amount the Company can borrow under the operating line.

LONG TERM DEBT

The Company's secured debentures are currently rated BBB(low) by DBRS.

OFF BALANCE SHEET ARRANGEMENTS

As of December 31, 2004, the Company had no off-balance sheet arrangements, other than the natural gas hedging contracts described in Financial and Other Instruments on page 28.

TRANSACTIONS WITH RELATED PARTIES

The Company had no transactions with related parties during 2004.

FOURTH QUARTER

The following table compares the results for the fourth quarters of 2004 and 2003:

[Dollar amounts in thousands, except per share figures]	Q4 2004	Q4 2003	% CHANGE
Deliveries (TJ)-Sales	2 385	2 549	(6.4)
Transportation service	8 185	7 541	8.5
Total	10 563	10 090	4.7
Customers at period end	39,291	39,106	0.5
Weighted average cost of gas purchased (\$ per GJ)	7.34	5.62	30.6
Operating revenues	\$ 40,757	\$ 39,448	3.3
Operating margin, consisting of Operating revenues less cost of sales	14,739	14,640	0.7
Income before income taxes	4,480	4,556	(1.7)
Net income	2,670	2,665	0.2
Operating cash flow	5,447	4,862	12.0
Basic Earnings per common share	0.72	0.72	—
Dividends paid per common share	0.20	0.20	—

Net income for the quarter ended December 31, 2004 was \$2.7 million, or the same as the quarter ended December 31, 2003. After providing for preferred share dividends, earnings per common share in the fourth quarter were \$0.72 in both 2004 and 2003. Net income in the fourth quarter of 2004 was reduced due to unaccounted for gas losses of \$0.4 million, net of income taxes. In addition, the expiry of an interest rate hedge in June of 2004 reduced interest expense in the fourth quarter of 2004 by \$0.1 million compared to the same period in 2003. Net income in the fourth quarter of 2003 was also negatively impacted by \$0.3 million relating to the increased administrative costs incurred in pursuing options to enhance shareholder value.

Operating revenues in the fourth quarter of 2004 increased to \$40.8 million as compared with \$39.4 million in the same period in 2003. The increase in operating revenue in the fourth quarter is attributed to an increase of \$2.5 million in revenue from off-system gas sales. These increases were offset by revenues from residential and commercial customers being \$0.7 million lower and a reduction of \$0.4 million in revenues from deliveries to industrial customers, compared to the corresponding period in 2003. The decrease in the Company's revenues from gas sales and transportation services in the fourth quarter of 2004 versus 2003 is due largely to a timing issue. The Company recorded higher revenues in the first half of 2004 which was reversed during the last six months of 2004, relative to the corresponding periods in 2003. In particular, the Company recorded \$1.7 million in deferred revenue, as approved by the Commission, in the latter half of 2003 in respect of the New Skeena Forest Products pulp mill in Prince Rupert as this mill was expected to reopen by mid-June 2003.

The pulp mill, however, remained idle and the Company's 2004 interim rates were then set assuming no revenue would be realized from service to the facility in 2004. This assumption resulted in rate increases to other customers which were applied to deliveries throughout 2004. As a consequence, the Company's revenues were an estimated \$0.9 million higher in the first half of 2004 than in the same period of 2003 and then offset by an equivalent reduction in revenues in the second half of 2004 compared to 2003.

Operating margin in the fourth quarter of 2004 increased to \$14.7 million, compared to \$14.6 million in the corresponding period in 2003, due to higher customer delivery charges, on average, in the fourth quarter of 2004 relative to the same period in 2003.

Capital expenditures in the fourth quarter of 2004 were \$5.2 million, compared to \$1.7 million in the comparable period in 2003, and included \$2.7 million relating to the Salmon River directional drill.

PROPOSED TRANSACTIONS

SECOND APPLICATION FOR APPROVAL OF AN INCOME TRUST OWNERSHIP STRUCTURE

On December 17, 2004, the Company filed a second application with the Commission seeking the approvals required pursuant to the Utilities Commission Act to transfer the ownership of the Company from the current common shareholders to an income trust. The PNG Income Trust would be owned by unit holders that would be comprised of the current shareholders that would exchange their common shares for units and new investors under an initial public offering of PNG Income Trust units. The new application addresses the Commission's concerns over deeming of capital structure components and income taxes. The application will be reviewed through a public hearing process, with a decision by the Commission expected in the third quarter of 2005. Any transfer of ownership would also require the approval of the shareholders of the Company, court approval and acceptable market conditions. The Company can give no assurances that the required approvals will be obtained, or that the conversion to an income trust ownership structure will occur.

CRITICAL ACCOUNTING ESTIMATES

Operating revenues include natural gas sales that are recorded on the basis of regular meter readings and estimates of customer usage from the last meter reading date to the end of the reporting period for such operating revenues. These estimates are made assuming normal consumption patterns, which may differ from actual consumption patterns. The estimates of unbilled operating revenue comprise 5.7 percent of the Company's operating revenues for 2004. Through future meter readings, the usage estimates are replaced with actual delivered volumes, which become reflected in the Company's financial results at that time.

The Company's subsidiary Pacific Northern Gas (N.E.) Ltd. is involved in a dispute with a customer over the payment for gas transported to the customer. The dispute relates to the customer's obligation to supply its own gas for transportation to its facilities, or failing that, to pay for gas delivered to those facilities. The Company believes it has a substantial case for recovery of the amounts billed and has recorded the related accounts receivable at management's best estimate of the amount ultimately recoverable. Approximately \$1.6 million relating to the dispute has been included in accounts receivable at December 31, 2004.

CHANGES IN ACCOUNTING POLICIES INCLUDING INITIAL ADOPTION

VALUATION OF PROPERTY, PLANT AND EQUIPMENT

In 2003, the CICA approved a new accounting standard for the recognition, measurement and disclosure of the impairment of long-lived assets (Section 3063). The new standard applies to non-monetary long-lived assets, including property, plant and equipment and intangible assets with finite useful lives. Under the new requirements, an impairment loss is recognized when the carrying amount of an asset to be held and used exceeds the sum of the undiscounted cash flows expected from its use and eventual disposition. An impairment loss is measured as the amount by which the asset's carrying amount exceeds its fair value. The Company adopted the new accounting standard prospectively, beginning January 1, 2004. Adoption of the new standard had no material effect on the Company's financial position or earnings in 2004.

In 2003, the CICA approved a new accounting standard for the recognition, measurement and disclosure of liabilities for asset retirement obligations and the associated asset retirement costs (Section 3110). A company will be required to recognize the fair value of a liability for an asset retirement obligation in the period in which the obligation is incurred when a reasonable estimate of fair value can be made. The Company adopted the new accounting standard prospectively beginning January 1, 2004, and adoption of the new standard had no material effect on the Company's financial position or earnings in 2004.

HEDGING RELATIONSHIPS

In 2003, the CICA approved new guidelines relating to the identification, designation, documentation and effectiveness of hedging relationships, for the purpose of applying hedge accounting (Accounting Guideline AcG-13). Specific documentation is required to qualify for hedge accounting prior to, at inception and throughout the term of the hedging relationship, including risk management policies, specific designation of hedging relationships, the nature of risk being hedged, the hedge objective or strategy, effectiveness assessment methodologies and accounting policies for hedge relationships, including income recognition. Retroactive and prospective effectiveness assessments will be required throughout the term of the hedge. The Company adopted the new accounting guideline prospectively beginning January 1, 2004, and adoption of the new guideline had no material effect on the Company's financial position or earnings in 2004.

FINANCIAL INSTRUMENTS AND OTHER INSTRUMENTS

The Company utilizes natural gas commodity hedging contracts in order to manage the volatility inherent in the prices of its natural gas purchases. It also utilizes interest rate hedging contracts to reduce the volatility of the interest expense associated with its floating rate debt instruments. As of December 31, 2004 the Company had no interest rate hedging contracts outstanding.

During the second quarter the Company completed its annual gas contracting and gas supply price management plan and filed it with the Commission for review and acceptance. The Commission accepted the plan as filed early in the third quarter of 2004. The plan called for gas price hedging, covering purchases over the period November 1, 2004 through October 31, 2005, to be completed in stages over the mid-July to mid-October 2004 period. Each hedging transaction was approved by the Company's price management committee.

At December 31, 2004, the Company had outstanding fixed price contracts covering approximately 3.2 million gigajoules of natural gas to be delivered in the months from January 2005 through October 2005 (representing approximately 21 percent of forecast annual system gas supply) at prices ranging from \$6.27 to \$9.87 per gigajoule. The fair value payable under the fixed price contracts at December 31, 2004 was \$3.9 million. In addition to the above mentioned fixed price contracts at December 31, 2004, the Company had also entered into natural gas price collar contracts to provide a ceiling and floor price for approximately 0.7 million gigajoules of natural gas to be delivered in the months of January and February of 2005, (representing approximately 5 percent of forecast 2005 system gas supply). The fair value payable under the collar contracts at December 31, 2004 was \$1.4 million. The fair value reflects the estimated amounts that the Company would pay at December 31, 2004 to terminate the fixed price contracts or collar contracts based on the estimated net cash flows under the terms of each contract.

OUTSTANDING SHARE DATA

At February 28, 2005, there were 200,000 preferred shares and 3,610,780 common shares outstanding. The common shares are the only issued voting securities of the Company, and it has no securities outstanding which may be converted into voting or equity securities.

RISK FACTORS

BUSINESS AND OPERATING RISK

Industrial customer concentration

In 2004, 75 percent of energy deliveries were made to the Company's three largest industrial customers, compared to 73 percent in 2003. One of these customers, totaling approximately 3 percent of annual deliveries, has a firm gas transportation agreement that would expire October 31, 2006 if either party gives twelve months notice of termination by October 31, 2005. In addition, the Company's contract with Methanex expires in 2009. The Company's ability to negotiate new contracts and to renegotiate existing contracts could be harmed by factors it cannot control, including reduced demand due to higher gas prices, the financial strength of major customers and the availability and price competitiveness of alternative energy sources.

The risk of non-performance by one or more of the large industrial customers may be analyzed and managed, but it cannot be entirely eliminated. In addition, the Company's service area is economically dependent upon industrial customers, many of which are tied to the forest sector. A prolonged decline in the forest and other related sectors could negatively impact deliveries to all customer classes.

Commodity price and supply risk

The average commodity cost of natural gas in 2004 remained at the historically high levels experienced in 2003. The prospect of fuel-switching and increased energy conservation by customers poses a risk with other energy sources being more cost competitive.

I MD&A

Adequate supplies of natural gas may not be available to satisfy committed obligations as a result of economic events, natural occurrences, and/or failure of a counterparty to perform.

Regulatory risk

The Company's asset base is subject to regulation (see "Regulatory activities"). Changes in the regulatory environment may be beyond the Company's control and may impact the viability of the assets, including the Company's ability to sustain or increase its profitability.

Facility risk

The Company carries on business in a geographic area of British Columbia where a large portion of its pipeline transmission system is located in extremely difficult terrain and where outages have, from time to time, been experienced in the past. Depending on circumstances, such outages may result in loss of revenues and/or increased maintenance costs.

FINANCIAL RISK

Commodity price volatility

Fluctuations in the price of natural gas could increase the working capital financing requirements and related costs for accounts receivable, and high customer rates may give rise to higher bad debt costs.

Recovery of deferral accounts

As part of the regulatory process, the Company maintains a number of deferral accounts including, without limitation, a gas cost variance account, the rate stabilization adjustment mechanism account and accounts for pipeline repair and rehabilitation.

The gas cost variance account is utilized to record variances in the Company's actual purchase cost of gas relative to the gas supply cost recovery charge included in customers' rates. At times, the gas supply cost recovery charges included in customers' rates can be below the actual purchase cost of gas resulting in a significant balance in the account which must be recovered from customers in future rates.

The Company's rates are set on the basis of forecast gas deliveries using normal heating degree-days. To the extent that actual degree-days are less than normal (that is, the weather is warmer than normal), revenues may be less than forecast. The revenue for residential and small commercial customers is protected by the rate stabilization adjustment mechanism deferral account approved by the Commission in 2003 to record differences between forecast and actual deliveries. When deliveries to customers are less than forecast, there may be significant balances in the account which are subject to recovery in future rates to customers.

The Commission requires the Company to record certain temporary pipeline repair and rehabilitation costs in deferral accounts for amortization into customer rates over a period of ten years on the basis that the customers benefit from such expenditures over that period of time.

The recovery of the Company's accumulated deferral accounts has an impact on the Company's liquidity requirements. Recovery of the deferral accounts through rates charged to customers is dependent upon regulatory approval and the ability to set rates high enough to recover such balances while maintaining the competitiveness of retail gas prices. Therefore, recovery of debit balance deferral accounts in future periods is a risk.

Capital availability

The Company's activities are financed by cash generated from operations and drawings under its operating line, together with proceeds from the issue of long term debt and share capital. Any constraint on the Company's ability to raise capital, including a credit downgrade, may negatively impact its investment activities, capital expenditures and hedging program.

Insurance risk

The Company maintains insurance against exposures to the physical loss of its pipeline, compressor and other above ground facilities as well as loss of earnings insurance relating to revenues from its large industrial customers. Based on past experience, the deductibles have increased over time and, depending on the number and severity of future outages, the financial impact on the Company could be material.

OTHER

LITIGATION

Pacific Northern Gas (N.E.) Ltd. is involved in a legal dispute with a customer over the payment for gas delivered to the customer. The dispute relates to the customer's obligation to supply its own gas for transportation to their facilities, or failing that, to pay for gas delivered to those facilities. The Company believes it has a substantial case for recovery of the amounts billed and has reduced the original accounts receivable to \$1.6 million which represents management's best estimate of the amount ultimately recoverable.

OUTLOOK

2005 REVENUE REQUIREMENTS APPLICATIONS

The Company's 2005 revenue requirements applications were filed with the Commission in late 2004. The applications project that deliveries to residential and commercial customers will be six percent higher than experienced in 2004. Achieving the delivery forecast will be dependent upon a number of factors, including weather, the volatility and absolute level of gas prices and the relative prices of competitive fuels. Natural gas prices for 2005 for gas purchases by the Company, based on forward gas prices as at February 1, 2005, are forecast to be approximately eight percent (\$0.54 per GJ) higher than the actual corresponding prices in 2004.

Additional information concerning the Company, including its most recent Annual Information Form, can be found at www.sedar.com.

I RESPONSIBILITY FOR FINANCIAL STATEMENTS

The consolidated financial statements and all information in this report have been prepared by and are the responsibility of management. The consolidated financial statements have been prepared in conformity with accounting principles generally accepted in Canada and, where appropriate, include certain estimated amounts that are based on informed judgements to ensure fair representation in all material respects. When alternative accounting methods exist, management has chosen those it considers most appropriate.

Management depends upon the Company's system of internal controls and formal policies and procedures to ensure the consistency, integrity and reliability of accounting and financial reporting, and to provide reasonable assurance that assets are safeguarded and that transactions are properly executed in accordance with management's authorization.

The Board of Directors is responsible for ensuring that management fulfills its responsibility for financial reporting and for final approval of the consolidated financial statements. The Board of Directors performs this responsibility primarily through its Audit Committee.

The Audit Committee is comprised solely of directors who are not employees of the Company or of its subsidiaries. The Audit Committee meets regularly with management, the internal auditors, and the shareholders' auditors to review the consolidated financial statements, the Auditors' Report and other auditing and accounting matters to ensure that each group is properly discharging its responsibilities. The Audit Committee reports its findings to the Board of Directors.

Deloitte & Touche LLP, the independent auditors appointed by the shareholders, have full and free access to the Audit Committee. The auditors performed an independent audit of the consolidated financial statements for the years ended December 31, 2004 and December 31, 2003. Their independent professional opinion on the fairness of these consolidated financial statements is included in the Auditors' Report.

January 28, 2005



Roy G. Dyce
President and Chief Executive Officer



Elizabeth A. Fletcher
Chief Financial Officer

AUDITOR'S REPORT I

TO THE SHAREHOLDERS OF PACIFIC NORTHERN GAS LTD.

We have audited the consolidated balance sheets of Pacific Northern Gas Ltd. as at December 31, 2004 and 2003 and the consolidated statements of income, retained earnings and cash flow 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 Canadian 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, 2004 and 2003 and the results of its operations and its cash flow for the years then ended in accordance with Canadian generally accepted accounting principles.

Deloitte & Touche LLP

Chartered Accountants
Vancouver, Canada,
January 28, 2005

I CONSOLIDATED BALANCE SHEETS

	2004	2003
As at December 31 (\$ in thousands)	\$	\$
ASSETS [notes 6 and 7]		
Current assets		
Cash and short term investments	—	313
Accounts receivable [notes 2,11 and 14]	23,304	25,100
Income taxes recoverable [note 4]	362	—
Inventories of supplies and natural gas	1,725	2,215
Prepaid expenses	215	133
	25,606	27,761
Plant, property and equipment [note 3]	176,780	174,348
Deferred charges		
Debt costs	754	915
Rate stabilization adjustment mechanism	1,788	864
Pipeline rehabilitation costs	1,128	1,093
Other	1,601	1,433
	5,271	4,305
	207,657	206,414

Commitments, guarantees and contingency [notes 13, 14 and 15]

See accompanying notes

On behalf of the Board:



Roy G. Dyce
Director



Robert F. Chase
Director

CONSOLIDATED BALANCE SHEETS I

	2004	2003
As at December 31 (\$ in thousands)	\$	\$
LIABILITIES		
Current liabilities		
Bank indebtedness [note 6]	6,046	2,900
Accounts payable and accrued liabilities [note 11]	16,037	15,113
Gas purchase variance payable	2,232	3,279
Income and other taxes payable	2,726	2,737
Long term debt due within one year [note 7]	4,382	4,382
	31,423	28,411
Non-current liabilities [note 5]		
Long term debt [note 7]	81,447	85,827
Deferred income taxes [note 4]	15,430	15,430
	97,284	101,481
	128,707	129,892
SHAREHOLDERS' EQUITY		
Preferred shares [note 8]	5,000	5,000
Common shares [notes 9 and 10]	9,009	8,960
Contributed surplus [notes 9 and 10]	2,567	2,379
Retained earnings	62,374	60,183
	73,950	71,522
	78,950	76,522
	207,657	206,414

I CONSOLIDATED STATEMENTS OF INCOME

	2004	2003
Years ended December 31 (\$ in thousands)	\$	\$
Operating revenues [notes 2 and 11]	137,755	133,727
Cost of sales [note 11]	88,954	84,417
	48,801	49,310
Operating and maintenance	12,093	12,387
Administrative and general	6,623	6,084
Amortization of deferred charges	763	503
Municipal and other taxes	3,941	3,982
Depreciation	7,877	7,873
	31,297	30,829
	17,504	18,481
Investment and other income	38	56
	17,542	18,537
Income deductions		
Interest on long term debt	7,564	7,536
Other	450	573
	8,014	8,109
Income before income taxes	9,528	10,428
Income taxes [note 4] - current	2,646	3,870
- deferred	1,474	890
	4,120	4,760
Net income for the year	5,408	5,668
For common shares		
Net income for the year	5,408	5,668
Dividends on preferred shares	337	337
Net income applicable to common shares, basic and diluted	5,071	5,331
Earnings per common share [note 1]		
Basic	1.41	1.49
Diluted	1.38	1.46
Weighted average number of common shares outstanding		
Basic	3,596,706	3,583,121
Diluted	3,667,095	3,641,240

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS I

	2004	2003
Years ended December 31 (\$ in thousands)	\$	\$
Balance, beginning of year	60,183	57,719
Net income for the year	5,408	5,668
	65,591	63,387
Preferred share dividends	337	337
Common share dividends	2,880	2,867
	3,217	3,204
Balance, end of year	62,374	60,183

See accompanying notes

I CONSOLIDATED STATEMENTS OF CASH FLOW

	2004	2003
Years ended December 31 (\$ in thousands)	\$	\$
OPERATING ACTIVITIES		
Net income for the year	5,408	5,668
Add (deduct) items not involving cash:		
Deferred income taxes	1,474	890
Depreciation and amortization	8,800	8,452
Stock option expense [note 10]	93	56
Other	(1,116)	(913)
Operating cash flow	14,659	14,153
Non-cash working capital changes [note 16]	1,708	(1,926)
Net cash provided by operating activities	16,367	12,227
INVESTING ACTIVITIES		
Additions to plant, property and equipment	(11,276)	(5,406)
Increase in deferred charges	(1,096)	(2,519)
Net cash used by investing activities	(12,372)	(7,925)
FINANCING ACTIVITIES		
Increase in bank indebtedness	3,146	2,900
Repayment of long term debt	(4,380)	(3,895)
Issue of common shares [note 9]	143	36
Dividends paid	(3,217)	(13,057)
Net cash used by financing activities	(4,308)	(14,016)
Decrease in cash and short term investments during the year	(313)	(9,714)
Cash and short term investments, beginning of year	313	10,027
Cash and short term investments, end of year	—	313

Supplemental cash flow information [note 16]

See accompanying notes

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS |

1. SUMMARY OF ACCOUNTING POLICIES

REGULATION

Pacific Northern Gas Ltd. and its wholly owned subsidiary, Pacific Northern Gas (N.E.) Ltd., are regulated utilities engaged in the transportation and distribution of natural gas. Their accounting records and practices conform to the requirements of the British Columbia Utilities Commission (the "Commission"). The Commission exercises statutory authority over matters such as rates, including rate of return on equity and capital structure, construction and operation of facilities, accounting practices, tolls, charges and contractual agreements with customers. In order to comply with orders issued by the Commission, the timing of recognition of certain revenues and expenses may differ from that which would otherwise be required under Canadian generally accepted accounting principles. Significant differences include, but may not be limited to the following accounting policies:

- Property, plant and equipment and related depreciation rates [notes 1 and 3]
- Deferral accounts [note 1]
- Income taxes [notes 1 and 4]
- Employee future benefit plans for post-retirement non-pension benefits [notes 1 and 5]
- Hedges, derivatives and other financial instruments [notes 1 and 14]
- Asset retirement costs [note 1]

USE OF ESTIMATES

The preparation of financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses and disclosure of contingent assets and liabilities. Actual results could differ from these estimates.

CONSOLIDATION

The consolidated financial statements include the accounts of Pacific Northern Gas Ltd. and Pacific Northern Gas (N.E.) Ltd. (collectively the "Company").

REVENUE RECOGNITION

Operating revenues include natural gas sales that are recorded on the basis of regular meter readings and estimates of customer usage from the last meter reading date to the end of the year. Operating revenues also include transportation services revenues that are recorded as service is provided, as well as sales of gas surplus to the needs of the Company's sales customers ("off system sales") that are recognized when the gas is delivered.

CASH AND SHORT TERM INVESTMENTS

Cash and short term investments are held for the purpose of meeting short term cash commitments and include bank balances and term deposits with maturities of less than 90 days.

I NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF ACCOUNTING POLICIES (CONT'D.)

INVENTORIES OF SUPPLIES AND NATURAL GAS

Inventories of supplies and line-pack natural gas are valued at the lower of cost determined on a first-in, first-out basis and net realizable value. Inventories of natural gas in storage are valued at the lower of average cost and net realizable value.

Included in, or deducted from, inventories of natural gas are amounts for natural gas to be received from, or returned to transportation service customers. This amount represents the difference between natural gas received on behalf of the transportation service customers and natural gas delivered to them.

PLANT, PROPERTY AND EQUIPMENT

Plant, property and equipment are recorded at cost less contributions in aid of construction. Cost includes an allowance for funds used during construction calculated at the Company's cost of capital. As directed by the Commission, the cost of depreciable assets retired, together with removal costs, less salvage is charged to accumulated depreciation. Gains or losses on disposal are not taken into income unless the disposal is outside the normal course of business or involves a major item of plant.

Depreciation is provided on a straight-line basis for plant in service at the commencement of each fiscal year at rates prescribed by the Commission. Average annual depreciation rates are as follows:

	2004	2003
	%	%
Transmission plant	2.7	2.9
Distribution plant	2.6	2.6
General plant	5.4	5.3
Processing plant	4.9	4.9
Composite rate	2.9	3.0

DEFERRAL ACCOUNTS

A. Debt costs

Debt costs comprises issue costs of long term debt, which are amortized on a straight-line basis over the term of the related issue.

B. Gas purchase variance payable

As directed by the Commission, gas purchase variance costs, which arise due to unanticipated commodity cost and demand fluctuations, are being charged or credited to cost of sales on a straight-line basis over periods ranging from one to three years.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS I

The amount of such credits included in cost of sales in 2004 was \$2,319,000 before income taxes [2003 – \$1,363,000].

C. Pipeline rehabilitation costs

In 2004, the Company deferred costs of \$193,000, net of income taxes, relating to temporary repairs of pipeline breaks [2003 - \$651,000]. The ultimate realization of these deferred charges is subject to a future decision of the Commission.

As directed by the Commission, pipeline rehabilitation costs are being amortized on a straight-line basis over ten years.

The total amount of amortization of pipeline rehabilitation costs in 2004 was \$158,000 [2003 - \$133,000].

D. Large industrial customer margin deferral

As directed by the Commission, a deferral account was set up to recover the lost margin from certain large industrial customers whose demand varied from expectations. Total credits of \$165,000 net of income tax, [2003 – costs of \$1,116,000] were deferred and included in other deferred charges. The amount deferred during the year ended December 31, 2003 is being amortized over three years. Amortization of \$372,000 has been included in net income during 2004 related to these deferred costs. The amount deferred during the year ended December 31, 2004 will be amortized commencing in 2005. The Company has applied to the Commission for a three-year amortization period for the 2004 deferral.

E. Rate stabilization adjustment mechanism

As directed by the Commission, the Company established a rate stabilization adjustment mechanism in 2003 to record the variance between actual and budgeted natural gas deliveries to residential and small commercial customers. The financial impact of the difference in deliveries is deferred for future recovery from or refund to the customers over a three-year period, commencing in the year following deferral. During 2004, \$1,206,000, net of income taxes, [2003 - \$864,000] was credited to income in respect of this deferral.

F. Interest deferral

As directed by the Commission, the Company has a short and long term interest deferral mechanism that mitigates exposure to fluctuations in short term and long term interest rates for variable interest rate debt instruments. In 2004, interest net of tax of \$259,000 was credited to deferred charges [2003 – \$53,000], to be refunded to customers over a two year period commencing 2005.

G. Propane air plant deferral

In 2004, the net book value of a propane air plant which is no longer in service with an undepreciated value of \$966,000 was removed from fixed assets and transferred to a deferral account for future recovery from customers over a period of twenty years commencing in 2005. The ultimate recovery of these deferred charges from customers is subject to a future decision of the Commission.

H. Other

As directed by the Commission, various other costs have been deferred to be recovered from future revenues over periods ranging from 1 to 10 years. During 2004, \$404,000 [2003 - \$52,000] was charged to income, net of income taxes, in respect of these deferred costs.

I NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF ACCOUNTING POLICIES (CONT'D.)

INCOME TAXES

The Company provides for income taxes using the income taxes currently payable method as directed by the Commission, except as described below. Under the income taxes currently payable method, no provisions are made for income taxes deferred as a result of differences in timing between the treatment for income tax and accounting purposes of various income and expenditure items [see note 4].

The Commission has directed that the deferral method of accounting for income taxes be followed for certain transactions within the Company. Under the deferral method of accounting for income taxes, reported earnings are charged with the income taxes related to those earnings. Differences between these taxes and taxes currently payable, arising mainly from differences in the timing of expense deductions, are recorded as deferred income taxes.

EMPLOYEE FUTURE BENEFIT PLANS

The Company accrues its pension obligations under employee benefit plans and the related costs, net of plan assets. The actuarial determination of the accrued benefit obligation uses the projected benefit method prorated on service (which incorporates management's best estimate of future salary levels, other cost escalations, retirement ages of employees, and other actuarial factors).

For the purpose of calculating the expected return on plan assets, those assets are valued at the market-related value. The market-related value of assets is determined as the average of the fair value of plan assets and four projected values. The projected values are determined by projecting the fair value as at a particular time (1 year, 2 years, 3 years and 4 years prior to the measurement date) to the measurement date using actual non-investment cash flows and an assumed investment return equal to the average market-related value return on three month T-Bills plus 2.5%.

Actuarial gains (losses) arise from the difference between actual long term rate of return on plan assets for a period and the expected long term rate of return on plan assets for the period, or from changes in actuarial assumptions used to determine the accrued benefit obligation. The excess of the net unamortized cumulative actuarial gain or loss over 10 percent of the greater of the benefit obligation and the fair value of the plan asset at the beginning of the year is amortized over the average remaining service period of the active employees. Past service costs from the plan amendments are amortized on a straight-line basis over the average remaining service period of employees active at the date of amendment.

The average remaining service period of the active employees covered by the pension plan is 14 years.

For the defined contribution plan maintained by the Company, contributions payable by the Company are expensed as pension costs.

Other retirement benefit plans are non-contributory health care and life insurance plans. Prior to 2004, the Company used the pay-as-you-go method of accounting for non-pension benefits as directed by the Commission. Beginning in 2004, both

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS |

the current service cost and the benefits paid to retirees are expensed and recovered in customer rates. The accrued benefit obligation is included on the balance sheet in non-current liabilities.

FINANCIAL INSTRUMENTS

Derivative and other financial instruments are utilized in connection with management of gas supply and interest rates. The Company enters into forward, future, swap, fixed price and option contracts to manage the impact of market fluctuations on assets, liabilities, or other contractual commitments. The Company defers the impact of changes in the market value of these contracts until such time as the associated transaction is completed.

Credit risk is the risk of loss from non-performance of suppliers, customers or financial counter parties to a contract. The Company maintains credit policies which management believes significantly minimize overall credit risk. These policies include a review of a counterparty's financial condition, measurement of credit exposure and monitoring of concentration of exposure to any one customer or counterparty.

EARNINGS PER COMMON SHARE

Basic earnings per common share are calculated using the weighted average number of common shares outstanding during the year. Diluted earnings per share are calculated using the treasury stock method whereby the weighted average number of common shares outstanding during the year is adjusted to reflect the potential exercise of dilutive share purchase options.

There are 84,200 [2003 – 71,500] stock options outstanding during the year that could potentially dilute basic earnings per share in the future that were not included in the computation of diluted earnings per share because the options' exercise price were greater than the average market price of the common shares.

STOCK BASED COMPENSATION

The Company has a stock option plan as described in note 10. Effective January 1, 2003 the Company adopted the amended recommendations of the CICA Handbook Section 3870, "Stock-based Compensation and Other Stock-based Payments". Under the amended standards of this Section, the fair value of all stock-based awards granted are estimated using the Black-Scholes model and are recorded in operations over their vesting periods. The compensation cost related to stock options granted after January 1, 2003 have been recorded in operations.

CHANGES IN ACCOUNTING POLICIES

A. Accounting for asset retirement obligations

Effective January 1, 2004, the Company adopted, as specified in Section 3110 of the Canadian Institute of Chartered Accountants ("CICA") Handbook, "Asset Retirement Obligations" ("ARO"). The new standard requires companies to recognize the fair value of a liability for an asset retirement obligation in the period in which it is incurred if a reasonable estimate of the fair value can be determined. The associated asset retirement cost is capitalized as part of the carrying amount of the related long-lived asset. The liability is accreted over the estimated useful life of the asset.

I NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF ACCOUNTING POLICIES (CONT'D.)

The Company's natural gas transmission and distribution long-lived assets are comprised principally of mains, service lines, compressors, and measuring and regulating equipment. Actual costs incurred for retirement and site restoration are charged to accumulated depreciation in accordance with regulatory treatment. The Company does not have a material legal retirement obligation for natural gas transmission and distribution long-lived assets and has not recorded an ARO liability.

B. Impairment of long-lived assets

On January 1, 2004, the Company adopted the new recommendations in Section 3063 of the CICA Handbook, "Impairment of Long-Lived Assets". The section establishes the recognition, measurement and reporting standards with respect to the impairment of long-lived assets held for use. Pursuant to the recommendations, a loss of value should be recognized when the carrying amount of a long-lived asset is not recoverable and exceeds its fair value. The adoption of these recommendations did not have a material impact on the financial statements of the Company.

C. Hedging relationships

Effective January 1, 2004, the Company adopted the new Accounting Guideline 13, "Hedging Relationships", which specifies the circumstances in which hedge accounting is appropriate, including specific requirements relating to the identification, documentation, designation and measurement of the effectiveness of hedges. The guideline also identifies situations where hedge accounting is to be discontinued.

D. Generally Accepted Accounting Principles

On January 1, 2004, the Company adopted the new recommendations in Section 1100 of the CICA Handbook, "Generally Accepted Accounting Principles". This section establishes standards for financial reporting in accordance with Generally Accepted Accounting Principles ("GAAP"). It describes what constitutes GAAP and its sources and states that non-rate regulated entities should apply every primary source of GAAP that deals with the accounting and reporting in financial statements of transactions or events encountered by them. Where applicable, it also requires rate-regulated entities to disclose how the accounting policies adopted by them differ from the primary sources of GAAP. The adoption of these recommendations did not have any impact on the financial statement presentation or net income.

E. Non-pension post retirement benefits

Effective January 1, 2004, the Company changed the method of expensing non-pension post-retirement benefits on a prospective basis. Prior to that date, only benefits paid were expensed. Beginning in 2004, and with the approval of the Commission, both the current service cost and the benefits paid are expensed. There was no effect on net income by adopting this new accounting policy in 2004, as the additional expense of \$180,000 was recovered from customers in rates.

COMPARATIVE FIGURES

Certain of the prior year figures have been reclassified to conform to the current year's presentation.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS I

2. MAJOR CUSTOMERS

The proportion of energy deliveries and operating revenues attributable to large industrial customers is as follows:

	2004		2003	
	ENERGY %	OPERATING REVENUES %	ENERGY %	OPERATING REVENUES %
Methanex Corporation	67	9	65	9
West Fraser Mills Ltd., Alcan Inc. and British Columbia Hydro and Power Authority	8	6	8	8

At December 31, 2004, 9% [2003 - 8%] of accounts receivable was attributable to these four customers. The Company is exposed to credit risk in the event of non-performance by customers, but does not anticipate such non-performance. The Company monitors the credit risk and credit rating of industrial customers on a regular basis. The maximum credit risk is the fair value of the accounts receivable.

3. PLANT, PROPERTY AND EQUIPMENT

	2004	2003
As at December 31 (\$ in thousands)	\$	\$
COST		
Transmission plant	180,290	177,779
Distribution plant	84,330	82,713
General plant	21,309	20,095
Processing plant	633	553
Construction in progress	4,579	649
Total plant, property and equipment	291,141	281,789
ACCUMULATED DEPRECIATION		
Transmission plant	74,142	69,389
Distribution plant	28,916	27,791
General plant	10,928	9,949
Processing plant	375	312
Total accumulated depreciation	114,361	107,441
	176,780	174,348

During the year, the Company received contributions in aid of construction of \$257,000 [2003 - \$176,000], which have been recorded as a reduction of distribution plant.

I NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

4. INCOME TAXES

Significant components of the Company's deferred tax liabilities are as follows:

	2004	2003
As at December 31 (\$ in thousands)	\$	\$
DEFERRED INCOME TAX LIABILITIES		
Capital cost allowance claimed for income tax purposes in excess of depreciation and amortization	14,462	14,462
Other	968	968
Deferred income tax liabilities	15,430	15,430

Income tax expense varies from the amount that would be expected if current rates were applied to income before income taxes for the following reasons:

	2004	2003
Combined Canadian federal and provincial statutory income tax rates, including surtaxes	% 35.6	% 37.6
Increase (decrease) in income taxes resulting from:		
Large corporations tax	3.1	4.5
Depreciation in excess of capital cost allowance	7.0	6.6
Amortization of intangibles	3.1	1.8
Capitalized overhead deducted for tax purposes	(4.9)	(3.9)
Other items	(0.7)	(1.0)
Effective rate of income taxes	43.2	45.6

From July 1, 1978 until its suspension on November 1, 1986, the deferral method was followed by the Company. Had the deferral method of accounting for income taxes been followed continuously since the inception of the Company, the deferred income tax liabilities and deferred income tax expense (recovery) would be:

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS I

	2004	2003
As at December 31 (\$ in thousands)	\$	\$
Unrecorded deferred tax liabilities - long term, beginning of year	14,805	15,084
Unrecorded deferred income tax (recovery) expense	(178)	(279)
Unrecorded deferred tax liabilities - long term, end of year	14,627	14,805
Deferred income tax liabilities, as reported	15,430	15,430
Total deferred income tax liabilities	30,057	30,235

5. EMPLOYEE FUTURE BENEFIT PLANS

The Company and its subsidiary have a number of funded and unfunded defined benefits plans, as well as defined contribution plans, that provide pension, other retirement and post-employment health and life insurance benefits for most employees. Its defined benefit plans are based on years of service and average earnings.

The measurement dates of the funded plans, as well as the effective dates of the most recent actuarial valuations and the next required actuarial valuations for the purpose of funding the funded plans are as follows:

	2004	2003
Measurement date of the plan assets and accrued benefit obligation	September 30, 2004	September 30, 2003
Effective date of the most recent actuarial valuation report for funding purposes	December 31, 2003	January 1, 2001
Effective date of the next required actuarial valuation report for funding purposes	December 31, 2006	December 31, 2003

The following table shows the allocation of the pension plan assets at the measurement dates:

	2004	2003
Cash and short term notes	4.2%	0.3%
Accrued income receivables (payables)	—	(0.3%)
Canadian bonds	38.4%	33.9%
Canadian equities	33.8%	36.7%
Foreign equities	23.6%	29.4%
	100.0%	100.0%

I NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

5. EMPLOYEE FUTURE BENEFIT PLANS (CONT'D)

Information about the defined benefit pension plans is as follows:

	2004	2003
(\$ in thousands)	\$	\$
ACCRUED BENEFIT OBLIGATIONS		
Balance, beginning of year	17,224	15,323
Current service cost	595	419
Employees' contributions	8	4
Interest cost	1,028	987
Benefits paid	(777)	(680)
Actuarial losses	1,157	1,171
Balance, as at measurement date	19,235	17,224
PLAN ASSETS		
Fair value, beginning of year	12,720	11,601
Actual return on plan assets	1,590	1,426
Employer contributions	497	369
Employees' contributions	8	4
Benefits paid	(777)	(680)
Fair value, as at measurement date	14,038	12,720
Funded status - plan deficit	(5,197)	(4,504)
Unamortized net actuarial losses	4,749	4,456
Unamortized past service costs	—	1
Unamortized transitional asset	(26)	(24)
Accrued benefit obligation as at measurement date	(474)	(71)
Employer contribution – between measurement date and year end	593	109
Accrued benefit assets end of year	119	38

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS I

The following is a summary of the significant actuarial assumptions used in measuring the Company's accrued pension benefit obligations:

	2004	2003
Accrued benefit obligation as of December 31, with a measurement date of September 30:		
Discount rate	6.00%	6.00%
Rate of compensation increase	3.25%	3.25%
Benefit cost for years ended December 31, with a measurement date of September 30:		
Discount rate	6.00%	6.50%
Expected long term rate of return on plan assets	7.50%	7.75%
Rate of compensation increase	3.25%	3.25%

The Company's pension plan expense is as follows:

	2004	2003
(\$ in thousands)	\$	\$
Current service cost	595	419
Interest cost	1,028	987
Expected return on plan assets	(930)	(1,116)
Amortization of past service costs	1	2
Amortization of net actuarial loss	214	40
Amortization of transitional asset	2	2
Net defined benefit pension plan expense	910	334
Defined contribution pension plan expense	46	49
Total pension expense	956	383

I NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

5. EMPLOYEE FUTURE BENEFIT PLANS (CONT'D)

Information about the unfunded non-pension post-retirement benefit obligation is as follows:

	2004	2003
(\$ in thousands)	\$	\$
Balance, beginning of year	4,739	4,167
Current service cost	180	160
Interest cost	284	273
Benefits paid	(192)	(101)
Actuarial loss (gain)	(849)	240
Balance, end of year	4,162	4,739
Funded status - plan deficit	(4,162)	(4,739)
Unamortized net actuarial losses	3,982	4,739
Accrued benefit obligation	(180)	—

Effective January 1, 2004, the Company changed the method of expensing non-pension post-retirement benefits on a prospective basis [note 1]. Prior to that date, only benefits paid were expensed. Beginning in 2004, both the current service cost and the benefits paid are expensed and recovered in customer rates. The accrued benefit obligation is included on the balance sheet in non-current liabilities.

The assumed extended health care cost trend used for measurement purposes is 10.0% per annum, grading down over 5 years to 5.0% and remaining at that level thereafter. The assumed dental premium trend used for measurement purposes is 7.0% per annum for the first 10 years and 6.0% per annum thereafter.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS I

The Company's non-pension post-retirement benefit expense is as follows:

	2004	2003
(\$ in thousands)	\$	\$
Current service cost	180	—
Benefits paid	192	101
Non-pension post-retirement benefit expense, as reported	372	101
Current service cost	—	160
Interest cost	284	273
Amortization of transitional obligation	123	123
Amortization of net actuarial loss	100	97
Less benefits paid, expensed above	(192)	(101)
Non-pension post-retirement benefit plan expense, accrual method	687	653

Total cash payments for employee future benefits are \$1,153,000 in 2004 and \$628,000 in 2003, consisting of cash contributed to funded pension plans, cash payments in respect of non-pension post-retirement benefits, and cash contributed to defined contribution pension plans.

6. BANK INDEBTEDNESS

	2004	2003
As at December 31 (\$ in thousands)	\$	\$
Bank overdraft	946	—
Bank demand operating line of credit	5,100	2,900
Bank indebtedness	6,046	2,900

The Company has a bank demand operating and hedge line of credit of \$25 million [2003 - \$25 million] which bears interest at prime rate or bankers' acceptance rates [December 31, 2004 - 4.25% ; December 31, 2003 - 4.5%] and provides funds for general corporate and working capital requirements. The amount available under this facility is subject to borrowing base requirements. The line of credit is collateralized by the pledge of a \$25 million debenture and a charge on certain accounts receivable and inventories. At December 31, 2004, the amount available under the facility was approximately \$6.4 million, \$6.1 million of which had been drawn. There were no outstanding letters of credit.

On January 24, 2005, a new operating line of credit was obtained from another lender, providing for bank demand operating and hedge lines of credit of \$ 35 million. The amount available under these facilities is subject to borrowing base requirements and has a term of 18 months. The new lines of credit are collateralized by the pledge of a \$40 million debenture and a charge on certain accounts receivable and inventories.

I NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

7. LONG TERM DEBT

	2004	2003
As at December 31 (\$ in thousands)	\$	\$
A. SECURED DEBENTURES		
RoyNat Debenture due January 15, 2011, bearing interest at a floating rate [December 31, 2004 – 5.557%], payable in monthly instalments of \$110,000, with a final instalment of \$120,000 at maturity.	8,040	9,360
RoyNat Debenture due December 15, 2012, bearing interest at a floating rate [December 31, 2004 – 6.057%], payable in monthly instalments of \$105,000, with a final instalment of \$2,505,000 at maturity.	12,480	13,740
2011 Series, 10.75% due December 13, 2011, payable in annual instalments of \$700,050, and \$800,000 in each of years 2009 and 2010 with a final instalment of \$5,000,000 at maturity.	9,400	10,100
2018 Series, 8.75% due November 15, 2018, payable in annual instalments of \$600,000, commencing November 15, 1999 and \$1,000,000 in each of the years 2014 to 2017, with a final instalment of \$7,000,000 at maturity.	16,400	17,000
2025 Series, 9.30% due July 18, 2025, payable in annual instalments of \$500,000, commencing July 18, 2004 with a final instalment of \$9,500,000 at maturity.	19,500	20,000
2027 Series, 6.90% due December 2, 2027, payable in annual instalments of \$500,000, commencing December 2, 2006 with a final instalment of \$9,500,000 at maturity.	20,000	20,000
B. CONSTRUCTION ADVANCES AND OTHER	9	9
	85,829	90,209
C. LESS LONG TERM DEBT DUE WITHIN ONE YEAR	4,382	4,382
	81,447	85,827

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS I

- A. Collateral for the Secured Debentures consists of a specific first mortgage on substantially all of the Company's plant, property and equipment and gas purchases and gas sales contracts, and a first floating charge on other property, assets and undertakings.
- B. Advances have been received from certain industrial concerns to enable construction of the facilities required to provide natural gas service. This financing is non-interest bearing and will be repaid as these customers meet their commitments for the purchase of natural gas.
- C. Payments required to meet sinking fund and retirement provisions of long term debt during the next five years and thereafter are as follows:

(\$ in thousands)	\$
2005	4,382
2006	4,882
2007	4,882
2008	4,882
2009	4,880
Thereafter	61,921
	85,829

8. PREFERRED SHARES

As at December 31 (\$ in thousands)	2004	2003
	\$	\$
AUTHORIZED		
1,400,000 cumulative redeemable junior preferred shares with a par value of \$10		
200,000 6.75% cumulative redeemable preferred shares with a par value of \$25 each		
ISSUED		
200,000 6.75% preferred shares	5,000	5,000

The 6.75% preferred shares are redeemable at the option of the Company at \$26 per share plus any accrued and unpaid dividends at the date of redemption.

I NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

9. COMMON SHARES

		2004	2003
As at December 31 (\$ in thousands)		\$	\$
AUTHORIZED			
6,020,000	Voting common shares with par value of \$2.50 each		
ISSUED			
3,603,580	Common shares [2003 – 3,583,880]	9,009	8,960

During 2004, the Company issued 19,700 common shares [2003 - 4,800] for cash consideration of \$143,000 [2003 - \$36,000] upon the exercise of employee options. Of this amount, \$94,000 [2003 - \$24,000] has been credited to contributed surplus, representing the excess of the issue price over the par value of the shares.

On December 17, 2004, the Company filed an application with the Commission seeking the approvals required pursuant to the Utilities Commission Act to transfer the ownership of Pacific Northern from the current common shareholders to an income trust called the "PNG Income Trust". The PNG Income Trust would be owned by unit holders that would be composed of the shareholders that exchange their common shares for units and new investors under an initial public offering of PNG Income Trust units. The application will be reviewed through a public hearing process, with a decision by the Commission expected in the second or third quarter of 2005. Any transfer of ownership would also require the approval of the shareholders of the Company, court approval, and acceptable market conditions.

10. STOCK OPTION PLAN

The Company has a stock option incentive plan under which share options are granted to certain of its employees. Share options are granted at an exercise price equal to the fair market value of the Company's common shares on the date of the grant.

Share options generally vest in five equal stages with the first stage vesting on the date of the grant, and the remainder in four equal annual stages commencing on the first anniversary of the date of the grant. The maximum term of options awarded is ten years.

As at December 31, 2004, there are 330,580 [2003 – 350,280] shares reserved for issuance pursuant to options that may be granted under the stock option incentive plan.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS I

In 2004, 25,900 options were issued at an exercise price of \$20.80.

Commencing in 2003, the Company accounts for its grants under this plan in accordance with the fair value based method of accounting for stock-based compensation [note 1]. The compensation cost that has been charged against income (and credited to contributed surplus) in 2004 is \$93,000 [2003 - \$56,000].

The fair value of each option grant is estimated on the date of the grant using the Black-Scholes option pricing model with the following assumptions:

	2004	2003
Dividend yield	4%	4%
Expected volatility (annualized)	44%	44%
Risk free interest rate	3%	3%
Expected years of option life (average)	7.5	7.5

A summary of the changes to the Company's stock option plan during the years ended December 31, 2004 and 2003 is as follows:

	2004		2003	
	NUMBER OF SHARES	WEIGHTED-AVERAGE EXERCISE PRICE \$	NUMBER OF SHARES	WEIGHTED-AVERAGE EXERCISE PRICE \$
Outstanding at beginning of year	272,200	14.52	247,000	14.45
Granted	25,900	20.80	34,600	14.15
Exercised	(19,700)	7.28	(4,800)	7.52
Expired	—	—	(4,600)	14.13
Outstanding at end of year	278,400	15.61	272,200	14.52
Options exercisable at end of year	212,600	15.78	197,260	15.38
Weighted average remaining contractual life	5.9 years		6.6 years	

I NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

10. STOCK OPTION PLAN (CONTI'D)

The following table summarizes information about the stock options outstanding and exercisable as at December 31, 2004:

EXPIRY DATE	OPTIONS OUTSTANDING	OPTIONS EXERCISABLE	EXCERCISE PRICE
November 7, 2005	19,400	19,400	\$ 20.00
March 14, 2006	13,200	13,200	18.75
March 14, 2007	12,700	12,700	20.75
March 24, 2008	11,500	11,500	30.50
March 11, 2009	14,700	14,700	24.50
March 16, 2010	25,200	25,200	15.50
March 21, 2011	41,900	30,980	7.85
April 27, 2011	11,700	11,700	6.50
March 15, 2012	32,600	19,200	13.50
July 4, 2012	35,000	35,000	13.50
March 13, 2013	34,600	13,840	14.15
March 2, 2014	25,900	5,180	20.80
	278,400	212,600	

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS I

11. RELATED PARTY TRANSACTIONS

The Company's transactions with related parties are as follows:

	2004	2003
(\$ in thousands)	\$	\$
Westcoast Energy Inc., parent company until December 18, 2003		
Transportation services received	—	876
Materials purchases and services received	—	463
Westcoast Energy Risk Inc., a company related through common control until December 18, 2003		
Services received	—	2,253
Duke Energy Marketing L.P., an entity related through common control from March 14, 2002 to December 18, 2003		
Natural gas purchases	—	19,385
Engage Energy Canada, L.P., an entity related through common control until December 18, 2003		
Natural gas purchases and services received	—	197
Natural gas sales	—	23,121

On December 18, 2003, all of the common shares of the Company held by Westcoast Energy Inc. were acquired by Tricor Pacific Capital, Inc.

Accounts payable and accrued liabilities as at December 31, 2003 include \$151,000 and accounts receivable at December 31, 2003 include \$647,000 relating to the above related party transactions.

These transactions were in the normal course of operations and were recorded at amounts established and agreed between the related parties, which approximate fair market value.

I NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

12. FAIR VALUES OF FINANCIAL INSTRUMENTS

The fair values of debt instruments included in the consolidated balance sheets are as follows:

	CARRYING VALUE		FAIR VALUE	
	2004	2003	2004	2003
As at December 31 (\$ in thousands)	\$	\$	\$	\$
Long term debt	85,829	90,209	96,410	92,501

The fair value of the Company's long term debt is estimated by reference to quoted market prices for actual or similar instruments.

The fair values of other financial instruments included in the consolidated balance sheets, including accounts receivable, bank indebtedness, and accounts payable and accrued liabilities approximate their carrying values due to their short term nature.

13. NATURAL GAS AND INTEREST RATE CONTRACTS

The Company's tolls are set using a forecasted price for gas. However, some of the Company's gas supply contracts contain pricing mechanisms that reflect monthly variations in the price of gas, rather than fixed prices.

At December 31, 2004, the Company had outstanding fixed price contracts covering approximately 3.2 million gigajoules of natural gas to be delivered in the months from January to October 2005 (representing approximately 23 percent of forecast 2005 system gas supply) at prices ranging from \$6.27 to \$9.87 per gigajoule. In addition, to the above mentioned fixed price contracts, at December 31, 2004 the Company has also entered into natural gas price collar contracts to provide a ceiling and floor price for approximately 0.7 million gigajoules of natural gas to be delivered in the months of January and February of 2005, (representing approximately 5 percent of forecast 2005 system gas supply).

At December 31, 2003, the Company had outstanding fixed price contracts covering approximately 3.4 million gigajoules of natural gas to be delivered in the months from January to October 2004 at prices ranging from \$4.92 to \$6.66 per gigajoule. In addition, at December 31, 2003 the Company had also entered into natural gas price collar contracts to provide a ceiling and floor price for approximately 1.0 million gigajoules of natural gas to be delivered in the months of January, February and March of 2004.

The difference between the price of gas used for toll purposes and the actual cost of gas purchased is deferred and refunded to or recovered from customers as directed by the Commission.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS |

The fair values (payable) receivable at December 31 under the contracts and options are as follows:

	2004	2003
As at December 31 (\$ in thousands)	\$	\$
Fixed price contracts	(3,855)	1,041
Collar contracts	(1,406)	(160)
	(5,261)	881

The fair values reflect the estimated amounts that the Company would receive or pay at December 31 to terminate the fixed price and collar contracts, based on the estimated future net cash flows under the terms of each contract, or the estimated amount that the Company would receive or pay at December 31 on settlement of the call options.

These estimated fair market values have no impact on earnings due to the regulated nature of the Company's operations. Based on the current regulatory process, any gains or losses arising from utility related financial instruments would be treated as part of the cost of service.

The Company's purchase commitments at December 31, 2004 under various gas supply contracts expiring through 2007 were as follows:

As at December 31 (\$ in thousands)	\$
2005	41,678
2006	933
2007	103
Thereafter	—

14. CONTINGENCY AND MEASUREMENT UNCERTAINTY

Pacific Northern Gas (N.E.) Ltd. is involved in a dispute with a customer over the payment for gas transported. The dispute relates to the customer's obligation to supply its own gas for transportation to their facilities, or failing that, to pay for gas delivered to those facilities.

On May 27, 2003 the Company commenced an action in the Supreme Court of British Columbia against the customer (the "Defendant"), claiming damages for breach of contract and for restitution for unjust enrichment relating to an outstanding accounts receivable balance in the amount of approximately \$2,020,000. The Company claimed that the Defendant had nominated no gas into the pipeline during a specified time period and, accordingly, the Defendant was obligated to pay for gas delivered to the Defendant at specified rates.

I NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

14. CONTINGENCY AND MEASUREMENT UNCERTAINTY (CONT'D)

On June 25, 2003, the Defendant filed a statement of defense in which it claimed that it was not the original party to the gas supply agreement at the time of the alleged deliveries and therefore not obligated to pay any back charges or, in the alternative, as the amount claimed represented a revision to the initial billings for gas deliveries, the provisions of the Company's gas tariffs restrict the period in which billing errors can be back charged to a customer.

On July 7, 2003, the Company filed a reply to the statement of defense in which it continued to assert its claim. The Company and the Defendant are still in the process of discovery with respect to the claims and a trial date has been set for October 2005.

The Company believes it has a substantial case for recovery of the amounts billed and has reduced the original accounts receivable to \$1.6 million which represents management's best estimate of the amount ultimately recoverable.

15. COMMITMENTS AND GUARANTEES

Under the terms of its gas transportation and supply agreements with certain customers, the Company has provided an indemnity for all damages, claims or actions arising from any act or accident in connection with the installation, presence, maintenance and operations of the Company's property and equipment, or in connection with the presence of gas deemed to be in the possession and control of the Company, and carries insurance to cover losses in the event of any claims under these provisions. The Company has also provided an environmental indemnity to certain secured debenture holders for any losses arising from non-compliance by the Company with applicable environmental laws.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS I

16. SUPPLEMENTAL CASH FLOW INFORMATION

Non-cash working capital changes:

	2004	2003
(\$ in thousands)	\$	\$
(Increase) decrease in:		
Accounts receivable	1,796	(3,864)
Income taxes recoverable	(362)	—
Inventories of supplies and natural gas	490	(850)
Prepaid expenses	(82)	67
Increase (decrease) in:		
Accounts payable and accrued liabilities	1,207	1,228
Gas purchase variance payable	(1,330)	601
Income and other taxes payable	(11)	892
Attributable to operating activities	1,708	(1,926)

Interest and tax payments:

	2004	2003
(\$ in thousands)	\$	\$
Income taxes paid	2,993	3,690
Interest paid	7,269	7,877

17. SEGMENTED INFORMATION

The Company operates in one industry and geographic segment, the transmission and distribution of natural gas within Canada. The consolidated financial statements have therefore not been segmented.

I 10 YEAR REVIEW

Years ended December 31 (\$ in thousands, except for share amount)	2004	2003	2002	2001
DELIVERIES (TJ)				
Residential	3 278	3 464	3 503	3 470
Commercial	2 715	2 909	2 967	2 936
Small Industrial	3 737	3 589	3 805	3 592
Large Industrial	29 241	26 676	29 188	21 783
	38 971	36 638	39 463	31 781
Customers At Year End	39,291	39,106	39,254	39,230
Average Rates Per GI*				
Residential	\$ 11.48	\$ 11.21	\$ 8.62	\$ 11.31
Commercial	9.76	9.71	7.49	10.16
Revenue				
Residential	\$ 37,627	\$ 38,815	\$ 30,204	\$ 39,239
Commercial	26,685	28,378	22,395	29,827
Small Industrial	8,585	9,545	9,479	10,539
Large Industrial	20,398	23,058	27,551	33,371
Off - System	43,949	33,403	18,763	24,736
Other	511	528	671	883
	137,755	133,727	109,063	138,595
Expenses				
Cost Of Sales	\$ 88,954	\$ 84,417	\$ 56,820	\$ 83,344
Operating	22,657	22,453	23,423	24,189
Interest	7,976	8,053	7,642	8,797
Depreciation & Amortization	8,640	8,376	9,653	10,581
Income Taxes	4,120	4,760	6,935	5,969
	132,347	128,059	104,473	132,880
Net Income	\$ 5,408	\$ 5,668	\$ 4,590	\$ 5,715
Per Common Share				
Earnings	\$ 1.41	\$ 1.49	\$ 1.20	\$ 1.52
Dividends Paid	0.80	3.55	—	—
Capitalization				
Non - Current Liabilities	\$ 407	\$ 224	—	—
Long Term Debt	81,447	85,827	\$ 90,224	\$ 79,539
Deferred Income Taxes	15,430	15,430	15,453	15,200
Preferred Shares	5,000	5,000	5,000	5,000
Common Equity	73,950	71,522	68,966	74,345
	\$ 176,234	\$ 178,003	\$ 179,643	\$ 174,084
Utility Plant				
In Service (Net)	\$ 172,201	\$ 173,699	\$ 176,711	\$ 178,741
Construction In Progress	4,579	649	603	560
	\$ 176,780	\$ 174,348	\$ 177,314	\$ 179,301

10 YEAR REVIEW |

2000	1999	1998	1997	1996	1995
4 216	4 202	3 688	3 796	3 056	2 644
3 543	3 108	2 897	3 162	2 559	2 217
3 875	3 694	3 704	2 972	2 120	1 905
23 137	31 573	28 498	32 365	30 981	27 890
34 771	42 577	38 787	42 295	38 716	34 656
39,665	39,238	38,808	37,669	27,978	26,638
\$ 8.20	\$ 6.16	\$ 5.80	\$ 5.68	\$ 4.90	\$ 5.30
5.96	4.84	4.41	4.41	3.58	4.58
\$ 34,557	\$ 25,881	\$ 21,380	\$ 21,552	\$ 14,971	\$ 14,026
21,115	15,036	12,763	13,952	9,157	10,161
9,349	6,356	4,912	4,848	3,354	4,013
36,108	29,967	31,883	35,166	33,842	30,237
14,108	-	754	1,804	1,068	2,119
496	498	452	539	431	442
115,733	77,738	72,144	77,861	62,823	60,998
\$ 61,750	\$ 24,778	\$ 20,887	\$ 27,295	\$ 14,975	\$ 19,943
23,297	22,876	20,615	19,877	16,611	16,518
9,293	9,050	9,307	8,903	8,822	8,915
8,866	8,094	8,322	7,067	6,792	5,646
5,689	5,815	6,559	6,793	8,238	3,785
108,895	70,613	65,690	69,935	55,438	54,807
\$ 6,838	\$ 7,125	\$ 6,454	\$ 7,926	\$ 7,385	\$ 6,191
\$ 1.83	\$ 1.92	\$ 1.73	\$ 2.16	\$ 2.01	\$ 1.67
0.56	1.12	1.10	1.00	0.96	0.94
\$ 82,158	\$ 85,593	\$ 88,894	\$ 92,135	\$ 74,862	\$ 80,056
15,653	12,789	11,126	7,119	1,863	15,514
5,000	6,715	10,261	13,609	18,910	5,000
68,968	64,311	61,459	59,142	54,785	51,038
\$ 171,779	\$ 169,408	\$ 171,740	\$ 172,005	\$ 150,420	\$ 151,608
\$ 182,016	\$ 182,766	\$ 178,614	\$ 176,103	\$ 156,995	\$ 154,421
1,335	151	1,610	1,459	1,244	1,929
\$ 183,351	\$ 182,917	\$ 180,224	\$ 177,562	\$ 158,239	\$ 156,350

I MANAGEMENT TEAM



DIRECTOR CORPORATE
DEVELOPEMENT

Kevin R. Teitge

VICE PRESIDENT,
OPERATIONS AND
ENGINEERING

Greg B. Weeres

PRESIDENT AND CHIEF
EXECUTIVE OFFICER

Roy G. Dyce

CHIEF FINANCIAL OFFICER

Elizabeth A. Fletcher

DIRECTOR REGULATORY
AFFAIRS AND GAS SUPPLY

Craig P. Donohue

CORPORATE INFORMATION |

DIRECTORS

ROBERT F. CHASE ^{1,2,4}

President and Chief Executive Officer

Lexacal Investment Corp.

West Vancouver, British Columbia

ROY G. DYCE

President and Chief Executive Officer

Pacific Northern Gas Ltd.

Coquitlam, British Columbia

J. TREVOR JOHNSTONE ^{1,5}

Managing Director

Tricor Pacific Capital, Inc.

West Vancouver, British Columbia

HUGH C. MORRIS ^{1,3}

Chair

Eldorado Gold Corporation

Delta, British Columbia

OFFICERS

R.F. CHASE

Chair of the Board

R.G. DYCE

President and Chief Executive Officer

G.B. WEERES

Vice President, Operations and Engineering

E.A. FLETCHER

Chief Financial Officer

C.P. DONOHUE

Director, Regulatory Affairs & Gas Supply

K.R. TEITGE

Treasurer

K. STARK-ANDERSON

Secretary

C.P. DONOHUE

Assistant Secretary

REGISTRAR & TRANSFER AGENT

COMPUTERSHARE TRUST COMPANY OF CANADA

Vancouver, Calgary, Regina, Winnipeg,

Toronto, Montreal

DIRECTORS

DAVID J. ROWNTREE ^{2,3}

Managing Director

Tricor Pacific Capital, Inc.

West Vancouver, British Columbia

RODERICK R. SENFT ⁴

Managing Director

Tricor Pacific Capital, Inc.

West Vancouver, British Columbia

DAVID G. UNRUH ^{3,5}

Vice Chair

Westcoast Energy Inc. and Union Gas Limited

West Vancouver, British Columbia

ARTHUR H. WILLMS ^{2,4,5}

Director

Westcoast Energy Inc. and Union Gas Limited

Vancouver, British Columbia

AUDITORS

DELOITTE & TOUCHE LLP

Vancouver, British Columbia

ANNUAL MEETING

The Annual and Special Meeting of the Shareholders of Pacific Northern Gas Ltd. will be held at the Hyatt Regency Vancouver Hotel, 655 Burrard Street, Stanley Room, Vancouver, British Columbia on April 28, 2005 at 10:30am (local time).

¹ Audit Committee

² Human Resources and Compensation Committee

³ Environment, Health and Safety Committee

⁴ Executive Committee

⁵ Corporate Governance Committee



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