

PACIFIC NORTHERN GAS LTD. MANAGEMENT'S DISCUSSION AND ANALYSIS DECEMBER 31, 2005

Date: February 16, 2006

This discussion should be read in conjunction with the enclosed audited consolidated financial statements of Pacific Northern Gas Ltd. (the "Company") for the year ended December 31, 2005. These consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles. All amounts are stated in Canadian dollars unless otherwise indicated.

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 and Outlook

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, Canada.

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 higher in the case of residential customers, than comparable electricity rates.

The Company's strategic focus in 2006 will be to continue to pursue recapitalization under an income trust ownership structure or a potential expansion of the transmission pipeline system to meet the requirements of a proposed LNG regasification facility near Kitimat in order to enhance shareholder value.

In 2005 the Company commenced preliminary study and investigation of a project to loop its main line transmission system from Kitimat to Summit Lake (the "KSL Project"). The KSL Project would be required to provide gas transportation services for the proposed Kitimat LNG Inc. liquefied natural gas ("LNG") receiving and regasification terminal to be located on the Douglas Channel approximately 15 kilometers southwest of Kitimat. If the terminal is constructed as planned, the Company will seek the necessary approvals to reverse the flow of its pipeline and expand pipeline capacity from the current 115 million cubic feet ("MMcf") per day to accommodate the delivery of 610 MMcf per day from the terminal.

Construction of the KSL Project is subject to a number of conditions including obtaining necessary permits for the Kitimat LNG Inc. terminal and the Company's pipeline expansion, acceptable commercial terms being negotiated between the Company and Kitimat LNG Inc., financing of both projects, and the securing of LNG supply by Kitimat LNG Inc.. The Company can give no assurances that the construction of the terminal by Kitimat LNG Inc. or the expansion of the Company's pipeline will proceed.

On December 17, 2004, the Company filed an application with the British Columbia Utilities Commission ("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". Under the plan, 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 application was reviewed at a public hearing before the Commission in May 2005. By decision dated September 9, 2005, the Commission granted conditional approval of the application, but included a reduction in the interest rate on subordinated debt compared to that applied for by the Company. On October 7, 2005, the Company applied for reconsideration and variance of the income trust decision, requesting the Commission approve the interest rates on subordinated debt as originally applied for by the Company. On October 28, 2005, the Commission approved the Company's request, and on November 18, 2005, requested that the Lieutenant Governor in Council of the Province of British Columbia approve the corporate amalgamation of the Company and its subsidiaries, a requirement before the conversion to an income trust can proceed. As of the date of this report, the Provincial approval is still pending.

The Company also believes it is highly desirable to resolve regulatory uncertainty, arising from the termination by Methanex Corporation of its transportation contract with the Company, prior to commencing the conversion process. The uncertainty, related to the level of future revenues the Company will be permitted to recover from its remaining customers will have a direct impact on cash flow and therefore the value of the Company as an income trust. The regulatory process to resolve this uncertainty is underway, and a resolution is expected in the second quarter of 2006. In addition, the Company is evaluating the efficiency of raising capital for the KSL Project under an income trust structure.

In addition to the approval granted by the Commission and the provincial Order in Council, the approval of the shareholders of the Company, court approval, consent of the existing bondholders and acceptable market conditions will also be necessary for the conversion to an income trust to proceed.

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 2005 was \$6.7 million, compared with \$5.4 million for 2004, or an increase of 23.1 percent. After providing for preferred share dividends, earnings per common share for 2005 were \$1.75 compared with \$1.41 for 2004. The increase in net income was primarily a result of an increase of \$0.7 million in return on equity approved by the Commission and a reduction in unaccounted for gas losses, net of income taxes, of \$0.5 million compared to 2004. Unaccounted for gas is the difference between the quantity of gas measured into the pipeline system and the quantity of gas delivered to customers, whether it is more or less. The impact of this unaccounted for gas loss, net of income taxes, was approximately \$0.2 million in 2005, compared to \$0.7 million in 2004. The increased return on equity resulted from approval of rates based on a higher deemed common equity proportion for the Western system compared to 2004.

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]

	2005	2004	2003
Deliveries (TJ) –			
Sales – Western system	3 686	3 902	4 086
Sales – Northeast system	3 302	3 436	3 668
Transportation service – Western system	24 018	29 803	27 182
Transportation service – Northeast system	1 838	1 830	1 702
Total	32 844	38 971	36 638
Customers at period end	39,295	39,291	39,106
Weighted average cost of gas purchased (\$ per GJ)	8.31	6.42	6.59
Operating revenues	\$159,950	\$137,755	\$133,727
Operating margin, consisting of operating revenues less cost of sales	48,663	48,801	49,310
Net income	6,660	5,408	5,668
Basic earnings per common share	1.75	1.41	1.49
Diluted earnings per common share	1.72	1.38	1.46
Total assets	215,210	207,657	206,414
Total long-term financial liabilities	92,214	97,277	101,481
Dividends paid per common share	0.80	0.80	3.55
Dividends paid per preferred share	1.69	1.69	1.69

Results of Operations

Deliveries to residential and commercial customers in 2005 were lower by 0.1 petajoules, or 2 percent, compared to deliveries in 2004. Some of the reduction in deliveries was due to weather, which was approximately 6 percent warmer in 2005 than in 2004. Deliveries to residential and small commercial customers in 2005 were lower by 0.6 petajoules, or 9 percent, compared to the forecast volumes used to set customer rates. In 2004, deliveries were 8 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 \$0.9 million (\$1.2 million in 2004), arising from differences between actual and forecast volumes for residential and small commercial customers

Operating revenues in 2005 increased to \$160.0 million as compared with \$137.8 million in 2004, largely due to the increase of \$12.2 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 to 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 2005 were significantly higher than 2004 and 2003 due to the higher commodity cost of gas.

Operating margin in 2005 decreased slightly to \$48.7 million, as compared with \$48.8 million in 2004. This decrease was due to anticipated reductions in expenses in 2005 that were used to determine customer rates.

Natural Gas Deliveries

Natural gas deliveries in 2005 totaled 32 844 terajoules* compared with 38 971 terajoules in 2004. A comparison of deliveries for the years 2005, 2004 and 2003 is provided in the following table:

Deliveries in terajoules	2005	2004	2003
Sales:			
Residential	3 135	3 279	3 464
Commercial	2 659	2 655	2 845
Small Industrial	689	778	825
Large Industrial	506	626	620
Total Sales	6 989	7 338	7 754
Transportation Service:			
Commercial	61	60	64
Small Industrial	2 887	2 958	2 764
Large Industrial – Methanex	20 497	25 952	23 820
Large Industrial – Other	2 410	2 663	2 236
Total Transportation Service	25 855	31 633	28 884
Total Deliveries	32 844	38 971	36 638

* 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 decreased 20 percent from 2004 to 2005 resulting primarily from Methanex permanently shutting down its methanol/ammonia complex in Kitimat in November 2005. Deliveries to other large industrial customers declined in response to historically high gas commodity prices.

Deliveries to residential and commercial customers declined in 2005 by approximately 2.3 percent from 2004 levels, largely due to the weather being approximately 7 percent warmer in 2005 compared to 2004.

Customer Additions

In 2005, 420 new services were connected to the Company's distribution systems, compared with 345 in 2004. This increase in service additions is the result of continued strong economic activity in the Northeast system. Although 420 new services were connected, the Company experienced a net increase of only 4 customers. This is a result of 416 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.

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 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 sold into other markets at prevailing market prices through off system sales. 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 2005, approximately 36 percent of gas purchases were hedged pursuant to the Company's gas price management plan (for further information as of December 31, 2005 with regard to 2005 gas supply, see Financial Instruments and Other Instruments below).

Most of the Company's gas supply is comprised 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 74 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 36 percent of the Fort St. John system's requirements. In Dawson Creek, approximately 7 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 that expired on October 31, 2005 with CanWest Gas Supply Inc. accounted for about 52 percent of 2005 purchases. Other supplies included purchases under seasonal and spot gas supply arrangements. In 2006, the CanWest gas supply is being replaced with gas purchases under a number of short term, seasonal and spot gas supply arrangements. Short term gas supply contracts are in keeping with current industry practices.

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"). Methanex has served notice to terminate its agreement with the Company effective February 28, 2006, as discussed below.

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 2005 accounted for approximately 62 percent of volumes delivered by the Company and approximately 7.6 percent of the Company's operating revenues. Transportation service to Methanex in 2005 was provided pursuant to an agreement that was set to expire on October 31, 2009, however on August 30, 2005, Methanex gave notice of its termination of the agreement. Under the terms of the agreement, Methanex is required to make a termination payment to the Company of approximately \$23.3 million on February 28, 2006, the effective date of the termination. Under the terms of a negotiated settlement with registered intervenors and approved by the Commission on November 17, 2005, the termination payment will be recorded as an interest bearing credit deferral, and will be amortized into income over the period March 1, 2006 to October 31, 2009. An annual demand charge based on a firm toll of 50 cents per gigajoule applied over the term of the agreement. In addition, under the contract, Methanex supplied a portion of the Company's internal gas requirements equal to four percent of deliveries to Methanex. The contract also included 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 2005.

Margin recovery in 2006 will be \$10.4 million lower than in 2005 due to the Methanex contract termination. This reduction is offset by credit amortization of \$5.6 million of the contract termination payment in 2006 resulting in a net margin reduction of \$4.8 million.

The Company has sought Commission approval in its 2006 revenue requirements application to recover the net \$4.8 million margin reduction from its remaining customers. Depending on customer growth, it may be necessary to seek further rate increases commencing in 2010 after the contract termination payment has been fully amortized in rates.

The transportation service and sales contracts with West Fraser and Alcan are in effect through December 31, 2013 and October 31, 2007, respectively. The agreement with Alcan will continue to be in effect beyond October 31, 2007 unless Alcan or the Company gives notice of termination. During 2005, deliveries to West Fraser and Alcan accounted for 6.0 and 1.3 percent, respectively, of the Company's total gas deliveries and 1.3 and 0.5 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. 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 Commission staff supervised negotiations between the Company and its customers under negotiated settlement guidelines issued by the Commission. Settlements are subject to final approval by the Commission.

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 the Company from the current common shareholders to the PNG Income Trust. The

PNG Income Trust unit holders were expected to be comprised of 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 May 2005.

In December 2004, the Company filed applications with the Commission for approval of new rates to take effect January 1, 2005 for all service areas. The revenue requirement applications for 2005 were considered by the Commission through a negotiated settlement process for the Western system and a written hearing process for the Fort St. John/Dawson Creek and Tumbler Ridge divisions.

The Commission issued its decisions on the 2005 revenue requirements applications on May 5, 2005 for the Fort St. John/Dawson Creek and Tumbler Ridge divisions. The 2005 allowed rate of return on common equity was 9.43 percent for the Fort St. John/Dawson Creek division and 9.68 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 on November 17, 2005 approved the settlement agreement reached between the Company and its customers respecting the Company's 2005 revenue requirements application for the Western system. The 2005 allowed rate of return on common equity was 9.68 percent including a 65 basis point premium over the low risk benchmark utility rate of return. Under the settlement agreement the interim rates effective January 1, 2005 were made permanent for all of 2005.

Western System

For 2005, 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 increased 2005 net earnings by \$0.3 million as actual 2005 deliveries to these customers were below forecast amounts. The Commission also accepted the Company's forecast of gas supply costs for 2005. Rate riders were approved in various amounts for 2005 to refund a credit balance accumulated in the gas purchase variance payable account. In 2005, 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 its 2006 Revenue Requirements Application, the Company identified plant, property and equipment assets which would not be required on an ongoing basis to provide service to its customers, having regard to the closure of the Methanex Corporation plant in late 2005. The Company has requested that compressor facilities, pipeline loops and various other fixed assets with a net book value of \$5.05 million be removed from rate base and transferred to a non-rate base, interest bearing deferral account effective December 31, 2005. The Company has applied for the deferral account to be amortized on a straight-

line basis over ten years commencing in 2006. The ultimate recovery of this deferred charge is subject to a future decision of the Commission.

In 2004, a propane air plant that was no longer in service with an undepreciated value of \$966,000 was removed from fixed assets and transferred to a deferral account, net of income taxes, for proposed future recovery from customers over a period of twenty years commencing in 2005. Under the terms of the 2005 negotiated settlement, \$165,000 of the amount deferred in 2004 was written off in 2005 and not collected in customer rates. A further \$242,000 was transferred to plant in service, and the remaining balance of the deferral, amounting to \$445,000 net of income taxes and salvage, will be amortized into customer rates over a ten year period beginning in 2005.

The 2006 revenue requirements application for the Western system was filed with the Commission in November 2005. The application sought approval of increased delivery charges and increased gas supply commodity charges, effective January 1, 2006. Approximately 95 percent of the gas delivery charge increase was due to the termination of the Methanex contract. In 2006, the Company applied for a deemed common equity ratio of 40 percent. The Commission approved interim gas delivery charge increases effective January 1, 2006 applying the requested deemed 40 percent common equity ratio. The permanent gas delivery rates will be determined under a negotiated settlement process, scheduled to commence in March 2006.

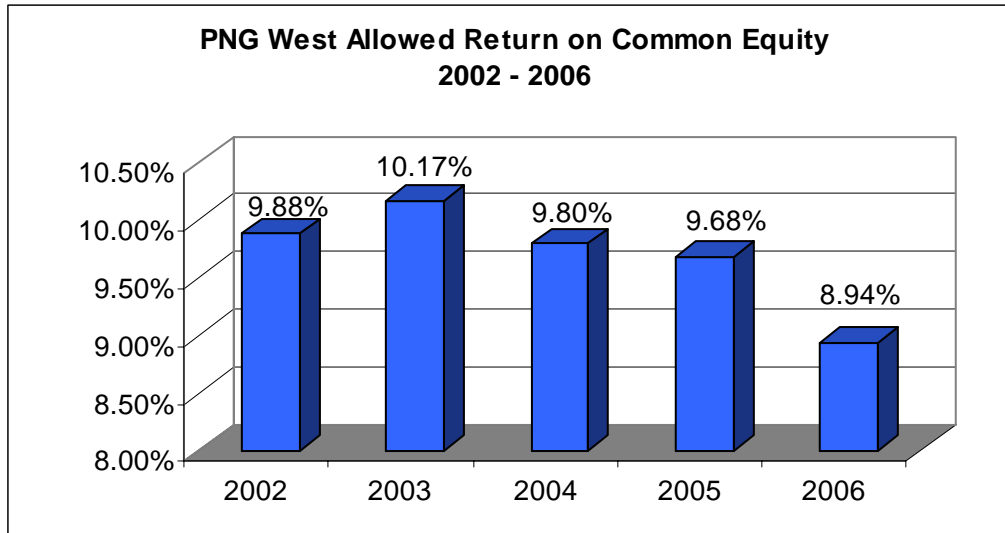
The Commission accepted the gas supply commodity charge adjustments applied for by the Company, effective January 1, 2006. The permanent gas supply commodity charges effective January 1, 2006 are almost equal to the gas supply charges approved by the Commission as of October 1, 2005 for the residential and commercial customers. Small industrial, seasonal and natural gas vehicle customer classes saw gas supply commodity charge increases compared to those in effect as of October 1, 2005.

The forecast 2006 residential and commercial deliveries contained in the 2006 revenue requirements application for the Western system are approximately 5 percent higher than actual gas deliveries to these customer classes in 2005. Deliveries to small industrial customers are projected to be approximately 2 percent lower in 2006 compared to actual gas deliveries in 2005.

Prior to the commencement of each calendar year, the Commission resets the allowed rate of return on common equity for each of the Company's regulatory divisions by a formula which uses, among other things, a consensus forecast of yields on 10-year Government of Canada bonds for the forthcoming year. Largely as a result of the lower 10-year bond yields which were in effect in the latter part of 2005 relative to the same period in 2004, the consensus forecast of 2006 10-year bond yields declined relative to the late 2004 consensus forecast of 10-year bond yields for 2005. Through application of the formula the approved rates of return on common equity for the Company have declined. In December 2005, the Commission confirmed that the formula resulted in an allowable 8.29 percent rate of return for a low risk benchmark utility in 2006. For the Company, a return on equity risk premium of 65 basis points applies to the Western

system resulting in an allowable rate of return on common equity of 8.94 percent for 2006.

The Commission is reviewing an application made by another utility in 2005 to review and revise the formula used to calculate the rate of return on common equity for public utilities regulated by the Commission. A decision on that application could impact the determination of the 2006 rate of return on common equity applicable to the Company.



Fort St. John / Dawson Creek Division

The Commission accepted the Company's forecast of gas supply costs for 2005. Rate riders were approved for 2005 to refund credit balances recorded in the gas purchase variance recoverable account at December 31, 2004 over a period of three years. In 2005, customer revenue from rate riders totalled \$0.1 million, which was applied, on an after tax basis, to reduce the gas purchase variance payable account.

The Fort St. John/Dawson Creek 2006 revenue requirements application, filed in December 2005, 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, 2006 at the level applied for which includes a deemed common equity of 36 percent and an allowable return on common equity of 8.69 percent for 2006. The gas supply commodity charge increases were approved as filed on a permanent basis. In total, the interim rate increases effective January 1, 2006 are higher by approximately 10 percent for both residential and small commercial customer classes compared to rates in effect as of December 31, 2005.

Tumbler Ridge Division

The Tumbler Ridge 2006 revenue requirement application was filed with the Commission in December 2005. The application sought Commission approval to increase the gas delivery

charge component of rates effective January 1, 2006 as well as the gas commodity charges. 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 11 percent for residential and small commercial customers relative to rates in effect on December 31, 2005.

A negotiated settlement process for the Fort St. John/Dawson Creek and Tumbler Ridge divisions' 2006 revenue requirements applications is scheduled to commence in March of 2006.

Summary of Quarterly Results

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

[Dollar amounts in thousands, except for per share data]

	2005				
	Mar. 31	June 30	Sept. 30	Dec. 31	Total
Operating revenues	\$47,798	\$30,293	\$32,238	\$49,621	\$159,950
Net income (loss)	\$3,984	\$137	(\$772)	\$3,311	\$6,676
Earnings (loss) per common share – basic	\$1.08	\$0.02	(\$0.24)	\$0.89	\$1.75
Earnings (loss) per common share – diluted	\$1.06	\$0.01	(\$0.24)	\$0.88	\$1.72
	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

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

Thousands of dollars	Payments Due by Period as of December 31, 2005				
	Total	Less than 1 year	1 - 3 years	4 - 5 years	After 5 years
Long Term Debt	\$81,440	\$4,880	\$9,760	\$9,960	\$56,840
Purchase Obligations	48,526	45,451	2,084	991	0
Total Contractual Obligations	\$129,966	\$50,331	\$11,844	\$10,951	\$56,840

The purchase obligations in the table above represent commitments by the Company to purchase natural gas or transportation service from third parties. 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 2005, the primary sources of funding were \$11.8 million of cash generated from operations, and a draw of \$4.1 million 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 2005, interest coverage using earnings before interest, income taxes, depreciation, and amortization was 3.619 times compared to 3.262 times in the prior year improving as a result of both higher earnings and a reduction in interest expense.

Funding costs

Interest expense

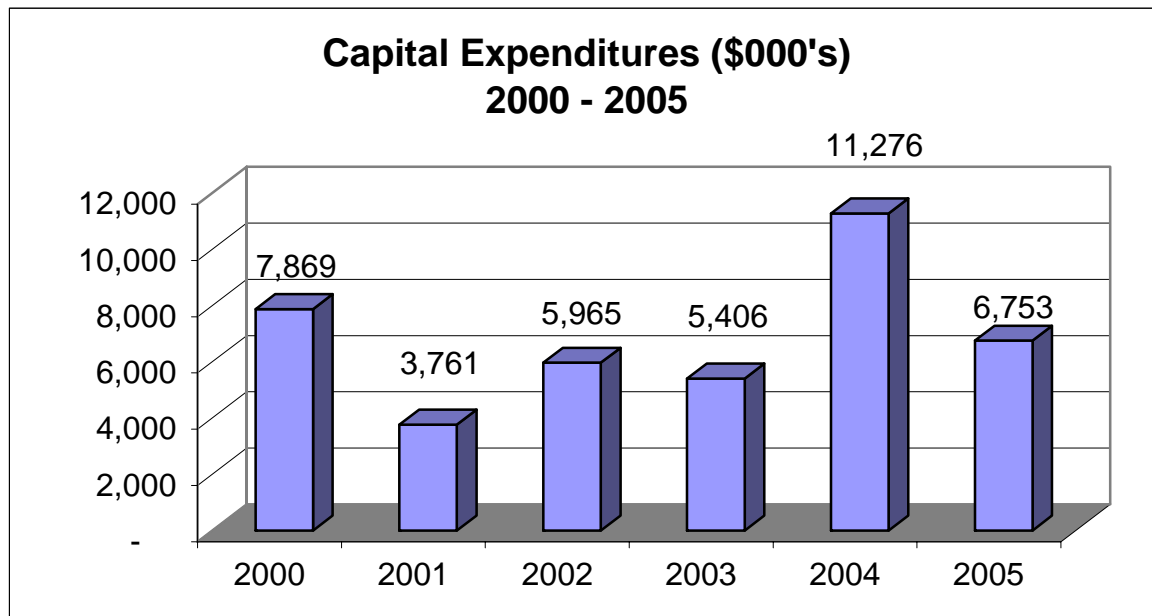
[Dollar amounts in thousands, except percent figures]

	2005	2004	2003
Long-term interest expense	7,083	7,564	7,536
Short-term interest expense	481	450	573
Total	7,564	8,014	8,109
Effective blended cost of debt (%)	8.7	9.0	8.7

The slight decrease in the effective blended cost of debt is due to higher average short term debt balances as a proportion of total debt. The interest rate on short term debt is lower than the interest rate on the Company's long term debt.

Capital Expenditures

Total capital expenditures in 2005 were 40 percent or \$4.5 million lower than those incurred in 2004 and 1.5 percent below the average level of expenditures for the last five years. Capital expenditures in 2004 included \$4.4 million that was out of the ordinary resulting from a requirement to directionally drill under the Salmon River to replace a duel underwater transmission system crossing. The majority of the capital expenditures in 2005 were for maintenance capital as well as customer additions to the distribution system on the Northeast system.



Capital Expenditures

[Dollar amounts in thousands]

	2005	2004	2003
Transmission system	\$3,103	\$7,032	\$2,310
Distribution system	2,233	2,905	2,356
Processing plant	112	80	41
Other	1,305	1,259	699
Total	\$6,753	\$11,276	\$5,406

Planned capital spending in 2006 is primarily directed toward distribution mains and services as well as transmission mainline rehabilitation, and is forecast to be approximately \$7.9 million. Contractual commitments have yet to be made for major planned capital expenditures for 2006. These capital expenditures will be funded from cash flow from operations.

Capital Resources

Composition of capital structure (percent)

	At December 31, 2005	At December 31, 2004	At December 31, 2003
Preferred shareholders' equity	2.9	2.9	2.9
Common shareholders' equity	44.6	43.3	42.2
Short-term debt	5.8	3.5	1.7
Long-term debt, including current portion	46.7	50.3	53.2
	100.0	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. Interim rates for 2006 are based on 36 percent of rate base for the Fort St. John / Dawson Creek and Tumbler Ridge divisions and 40 percent for the PNG West division.

Equity

The book value of the common shares at December 31, 2005 was \$21.43 per share, compared to \$20.52 per share at December 31, 2004.

The Company's preferred shares are currently rated Pfd-3(low) by Dominion Bond Rating Service ("DBRS"). On September 1, 2005, DBRS placed the ratings of the Company's preferred shares under review with negative implications, following the announcement of the termination of the Methanex agreement.

On March 11, 2005, the Company filed a prospectus for the public offering of 1,338,477 common shares of the Company owned by Tricor Acquisition (STP) Inc. ("Tricor"), at a price of \$19.40 per common share, for gross proceeds of approximately \$26 million. The

common shares offered by Tricor represented 37 percent of the Company's outstanding common shares and 100 percent of Tricor's interest in the Company. The transaction was subsequently completed on April 12, 2005. The Company did not sell any newly issued common shares as part of this offering and did not receive any of the proceeds from the sale of the common shares by the selling shareholder.

Dividends

Preferred dividends totaling \$1.6875 per share were paid in 2005, the same as in 2004.

Common dividends totaling \$0.80 per share were paid in 2005, compared to \$0.80 per share paid in 2004 and \$3.55 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 longer 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 2005, compared to \$3.2 million paid in 2004 and \$13.1 million paid in 2003.

Short-term Debt

Commencing in January 2005, the Company arranged new credit facilities which included 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. The operating line of credit and the risk management facility were collateralized by the pledge of a \$40 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 operating line of credit. At December 31, 2005, the amount available under the facility was approximately \$18.5 million, of which \$10.2 million had been drawn. The Company provided covenants to its operating lender, all of which were complied with during 2005.

Long-term Debt

The Company's secured debentures are currently rated BBB(low) by DBRS. On September 1, 2005, DBRS placed the ratings of the Company's secured debentures under review with negative implications, following the announcement of the termination of the Methanex agreement.

Off Balance Sheet Arrangements

As of December 31, 2005, the Company had no off-balance sheet arrangements, other than the natural gas hedging contracts described in Financial and Other Instruments below.

Transactions with Related Parties

The Company had no transactions with related parties during 2005 or 2004.

Fourth Quarter

The following table compares the results for the fourth quarters of 2005 and 2004:

[Dollar amounts in thousands, except per share and per GJ figures]

	<i>Q4 2005</i>	<i>Q4 2004</i>	<i>Percent Change</i>
Deliveries (TJ) – Sales	2 191	2 385	(8.1)
Transportation service	3 293	8 185	(59.8)
Total	5 484	10 570	(48.1)
Customers at period end	39,295	39,291	0.0
Weighted average cost of gas purchased (\$ per GJ)	10.20	7.34	39.0
Operating revenues	49,621	\$40,757	21.7
Operating margin, consisting of			
Operating revenues less cost of sales	14,259	14,739	(3.3)
Income before income taxes	5,042	4,480	12.5
Net income	3,311	2,670	24.0
Operating cash flow	5,279	5,447	(3.1)
Basic Earnings per common share	0.89	0.72	23.6
Dividends paid per common share	0.20	0.20	-

Net income for the quarter ended December 31, 2005 was \$3.3 million, compared with \$2.7 million for the quarter ended December 31, 2004. After providing for preferred share dividends, earnings per common share in the fourth quarter of 2005 were \$0.89, compared with \$0.72 for the quarter ended December 31, 2004. Net income in the fourth quarter of 2004 was reduced by \$0.4 million due to unaccounted for gas losses.

Operating revenues in the fourth quarter of 2005 increased to \$49.6 million as compared with \$40.8 million in the same period in 2004. The increase in operating revenue in the fourth quarter is attributed to an increase of \$5.1 million in revenue from off-system gas sales. In addition, revenues from residential and commercial customers were \$3.5 million higher and revenues from deliveries to industrial customers were \$0.2 million higher compared to the corresponding period in 2004. The increase in revenues is primarily due to the increase in gas supply costs embedded in sales customers' rates compared with the corresponding period in 2004.

Operating margin in the fourth quarter of 2005 decreased to \$14.3 million, compared to \$14.7 million in the corresponding period in 2004, due to lower customer deliveries in the fourth quarter of 2005 relative to the same period in 2004.

Capital expenditures in the fourth quarter of 2005 were \$3.0 million, compared to \$5.2 million in the comparable period in 2004. Expenditures in the fourth quarter of 2004 included \$2.7 million relating to the Salmon River directional drill.

Proposed Transactions

Kitimat Summit Lake Looping Project

On October 18, 2005 the Company engaged two international banks as co-arrangers for the project financing of the proposed KSL project. These banks were also concurrently engaged by Kitimat LNG Inc. as co-arrangers for the project financing of the proposed regasification terminal.

In 2005 the Company incurred costs of \$0.9 million associated with the KSL Project. Kitimat LNG Inc. is obligated to fund \$0.4 million of this amount under an agreement with the Company. If construction of the Kitimat LNG Inc. terminal proceeds, the deferred costs will be transferred to construction work in progress and the Company will be required to refund all of the funding provided by Kitimat LNG Inc.

In the event the terminal is not constructed, the Company will seek recovery of the deferred costs in future customer rates. In the event the Company is permitted to recover any deferred KSL preliminary development costs in its future rates, the recovery of costs will be shared on a pro rata basis with Kitimat LNG Inc. in proportion to the funding provided by each party.

Construction of the KSL Project is subject to a number of conditions including obtaining necessary permits for the Kitimat LNG Inc. terminal and the Company's pipeline expansion, acceptable commercial terms being negotiated between the Company and Kitimat LNG Inc., financing of both projects, and the securing of LNG supply by Kitimat LNG Inc.. The Company can give no assurances that the construction of the terminal by Kitimat LNG Inc. or the expansion of the Company's pipeline will proceed.

Second Application for Approval of an Income Trust Ownership Structure

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 the Company from the current common shareholders to the PNG Income Trust. Under the plan, 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 application was reviewed at a public hearing before the Commission in May 2005. By decision dated September 9, 2005, the Commission granted conditional approval of the application, but included a reduction in the interest rate on subordinated debt compared to that applied for by the Company. On October 7, 2005, the Company applied for reconsideration and variance of the income trust decision, requesting the Commission approve the interest rates on subordinated debt as originally applied for by the Company. On October 28, 2005, the Commission approved the Company's request, and on November 18, 2005, requested that the Lieutenant Governor in Council of the Province of British Columbia approve the corporate amalgamation of the Company and its subsidiaries, a requirement

before the conversion to an income trust can proceed. In addition to the approval granted by the Commission and the provincial Order in Council, the approval of the shareholders of the Company, court approval, consent of the existing bondholders and acceptable market conditions will also be necessary for the conversion to an income trust to proceed. 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 6 percent of the Company's operating revenues for 2005. 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.

Changes in Accounting Policies Including Initial Adoption

Changes Adopted in 2005

Disclosure by Entities Subject to Rate Regulation

Effective December 31, 2005, the Company adopted the new Accounting Guideline AcG-19, Disclosure by Entities subject to Rate Regulation, which applies to years ending on or after December 31, 2005. AcG-19 provides guidance about certain aspects of the disclosure and presentation of information of entities providing services or products for which customer rates are established or approved by a regulator. The objective is to ensure that financial statement users are better informed about the existence, nature and effects of all forms of rate regulation. If rate regulation has an impact on the accounting treatment of a transaction, the entity should make mention of it and provide additional information about the impact on its financial statements.

New Accounting Standards

New accounting standards will be in effect for fiscal years beginning on or after October 31, 2006 for hedge accounting, recognition and measurement of financial instruments and disclosure of comprehensive income. The Company is currently investigating the impact of these new standards.

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, 2005 the Company had no interest rate hedging contracts outstanding.

During the first quarter the Company completed its annual gas contracting and gas supply price management plan and filed it with the Commission for review and acceptance. In response to discussions with Commission staff, the plan was slightly modified in early June. The Commission accepted the modified plan later in June 2005. The plan called for gas price hedging, covering purchases over the period November 1, 2005 through October 31, 2006, to be completed in stages over the June to September 2005 period. Each hedging transaction was approved by the Company's price management plan committee and reported to the Commission.

At December 31, 2005, the Company had outstanding fixed price contracts, natural gas swap contracts, and call options relating to natural gas supply as follows:

Financial instrument	Notional Quantity (GJ's)	Percent of Annual Gas Purchases	Delivery period	Price Range (per GJ)	Estimated Fair Value Receivable (\$000's)
Fixed price contracts	450 000	4.6	Jan. to Mar. 2006	\$5.83 to \$10.00	(\$167)
Natural gas swap contracts	1 193 000	12.1	Jan. to Oct. 2006	\$7.85 to \$10.60	\$1,670
Call options	1 219 500	12.3	Jan. to Mar. 2006	Caps from \$10.00 to \$15.00	\$633
Total	2 862 500	29.0			\$2,136

The fair value reflects the estimated amounts that the Company would receive at December 31, 2005 to terminate the fixed price contracts, natural gas swap contracts or call options, based on the estimated net cash flows under the terms of each contract.

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.

At December 31, 2004, the Company had outstanding fixed price contracts and collar contracts relating to natural gas supply as follows:

Financial instrument	Notional Quantity (GJ's)	Percent of Annual Gas Purchases	Delivery period	Price Range (per GJ)	Estimated Fair Value Payable (\$000's)
Fixed price contracts	3 219 000	22.8	Jan. to Oct. 2005	\$6.27 to \$9.87	(\$3,855)
Collar contracts	716,850	5.1	Jan. to Feb. 2005	\$8.22 to \$10.25	(\$1,406)
Total	3 935 850	27.9			(\$5,261)

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.

Natural gas prices for 2006 for gas purchases by the Company, based on forward gas prices as at February 15, 2006, are forecast to be approximately 2 percent (\$0.16 per GJ) lower than the actual corresponding prices in 2005.

Disclosure Controls and Procedures

The Chief Executive Officer and Chief Financial Officer evaluated the effectiveness of the Company's disclosure controls and procedures (as defined in the rules of the Canadian Securities Administrators) and concluded that the Company's disclosure controls and procedures were effective as of December 31, 2005 and in respect of the 2005 year end reporting period.

Outstanding Share Data

At February 16, 2006, there were 200,000 preferred shares and 3,626,180 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

Industrial customer concentration and potential for termination of contracts

In 2005, 70 percent of energy deliveries were made to the Company's three largest industrial customers, compared to 75 percent in 2004. The Company's contract with Methanex was terminated effective February 28, 2006. The Company's contract with West Fraser expires in 2013 and may be terminated prior to that date upon payment of an amount described in the contract, or without payment in certain circumstances. Alcan, whose deliveries account for approximately 1.3 percent of annual deliveries, has a firm gas transportation agreement that would expire October 31, 2007 if either party gives twelve months notice of termination by October 31, 2006. The Company's ability to negotiate new contracts and to renegotiate existing contracts could be impacted 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.

The Company's service area is economically dependent upon industrial customers for its economic stability. These customers produce commodities that are subject to world commodity fluctuations. Gas deliveries to these customers have been and may in the future be affected by their ability to continue to operate during sustained periods of low commodity prices. A prolonged decline in a sector affects all customer classes. For example, in the Western region many of the Company's industrial customers are involved in the forest sector. A prolonged decline in the forest sector could negatively impact gas deliveries to a lumber mill, as well as negatively impacting delivery requirements of commercial and residential customers who directly or indirectly provide services to that mill.

Commodity Price and Supply Risk

Over the last three years, the commodity cost of natural gas has been highly volatile. The average cost of natural gas in 2005 was approximately 30 percent higher than in 2004 and 26 percent higher than in 2003. When prices are high, the prospects of fuel-switching and increased energy conservation pose a risk, as other energy sources can become more cost competitive. Fluctuations in the price of natural gas may increase the Company's working capital financing requirements and related costs for accounts receivable, and may give rise to higher bad debt costs.

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.

Usage Risks

Natural gas competes with other forms of energy available to the Company's customers and end-users, including electricity, wood and coal and, in the case of certain industrial customers, wood waste. The primary competitive factor is price. Changes in the availability or price of natural gas and other forms of energy, the level of business activity, conservation, legislation, governmental regulations, the ability to convert to alternative fuels, weather and other factors affect the demand for natural gas in the Company's service areas. In addition, because electricity prices in British Columbia for residential and certain other customer classes have been set based primarily on the historical average cost of production, they have remained artificially low compared to market priced natural gas. Over time, this distortion in pricing signals may affect decisions by British Columbia consumers, potentially decreasing the use of natural gas by customers.

Over the past several years the average amount of natural gas consumed by residential customers has declined. This decline is attributable to a number of factors, including the replacement of older heating equipment by newer, more efficient equipment, more

energy efficient housing, and energy conservation measures in response to higher gas prices and poor economic conditions in the Western region.

Regulatory Risk

The Company's asset base is subject to regulation by the Commission (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.

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 charges 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 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, and is therefore at risk.

Liquidity, Cash Flow, and Capital Availability Risks

The Company's credit facilities include a \$20 million operating line and a \$15 million risk management facility. The operating line is subject to borrowing base requirements which may restrict the amount that the Company can borrow under the line at any point in time. In addition, the credit facilities are also subject to financial covenants that may act to restrict the amount that can be borrowed under the operating line. The credit facilities also contain a restriction on payments that may have the effect of reducing or

eliminating the dividends that the Company can pay in the absence of access to new long term debt.

The Company is currently relying on operating cash flow to fund capital expenditures, scheduled amortizations of long term debt and payment of dividends. While operating cash flow is currently adequate for those purposes, there is no assurance that it will be in the future. 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.

Facility and Insurance 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 or increased maintenance or capital costs.

The Company maintains insurance against exposures to the physical loss of its pipeline, compressors and other above ground facilities as well as loss of earnings insurance relating to revenues from its large industrial customers. Based on past insurance claims for damage to the pipeline caused by slides, washouts, and other natural events, the Company's deductibles have increased. Depending on the number and severity of future outages, the financial impact on the Company could be material.

Environmental and Safety Risks

The Company is required to comply with existing environmental laws and regulations. It is possible that increasingly strict environmental laws, regulations and enforcement policies, and potential claims for damages and injuries to property, employees, other persons and the environment resulting from current or discontinued operations, could result in substantial costs and liabilities in the future. In particular, the Company could be exposed to significant operational disruptions and environmental liability in the event of an accident involving natural gas. The Company believes it has taken all reasonable and prudent steps to minimize its exposure in the case of safety or environmental incidents.

The Government of Canada ratified the Kyoto Protocol on December 17, 2002. No final decisions have been made on the targets, measures and regulations for industry sectors and companies to ensure compliance, and development of the methodology is currently in flux. It is not possible at this time to measure the extent of the impact of the Kyoto Protocol on the Company.

Derivatives Risk

The Company uses derivative and other financial instruments in connection with the management of gas supply prices and interest rates. Forward, future, swap, fixed price and option contracts are used to manage the impact of market fluctuations on assets, liabilities or other contractual commitments. The Company could, however, incur

financial losses in the future as a result of market or price volatility. Furthermore, because the valuation of these financial instruments can involve estimates, changes in the assumptions underlying these estimates can occur, changing the Company's valuation and potentially resulting in financial losses. This risk could affect the Company's liquidity, and regulatory approval would be required for the recovery of related costs through future rate adjustments.

Other

Litigation

Pacific Northern Gas (N.E.) Ltd. was involved in a legal dispute with a customer over the payment for gas transported to the customer. The dispute related 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 September 29, 2005 a settlement was negotiated between the parties, and payment of the agreed amount was received on October 11, 2005. There was no impact on net income in 2005 arising from the settlement of the dispute.

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