



PACIFIC NORTHERN GAS LTD.

**ANNUAL
INFORMATION FORM**

For the period covering 12 months ending December 31, 2004

March 24, 2005

TABLE OF CONTENTS

GLOSSARY	4
SPECIAL NOTE REGARDING FORWARD LOOKING STATEMENTS	4
THE COMPANY	4
Corporate Structure	4
General Development of the Business	5
BUSINESS OF THE COMPANY	6
Overview	6
Western Region	8
Transmission Pipeline System	8
Distribution System and Franchise Agreements	8
Northeast Region	9
Transmission and Distribution Facilities	9
Franchise Agreements	9
Properties	9
Gas Sales and Transportation	10
Large Industrial Customers	12
Overview	12
Methanex	12
West Fraser	13
Alcan	13
BC Hydro	14
New Skeena Forest Products Inc.	14
Natural Gas Supply	14
Customer Additions	15
Government Regulation	16
General	16
Rate Regulation	16
Western Region	17
Northeast Region	19
Rate Base and Common Equity	20
Application to Commission to Convert the Company to an Income Trust Structure	20
Background	20
Initial Decision, Subsequent Application and Approval Requirements	21
Engineering and Operations	22
In-Line Inspection	22
Compressor Control Systems	22
Khyex River Slide	23
Work Channel Slide	23
Capital Expenditures	23
Operating Activities	23
Social and Environmental Policies and Environmental Protection	23
Employees	24
Trends and Competition	24

RISK FACTORS	25
Potential for Termination of Large Industrial Contracts.....	25
Conversion to an Income Trust requires Regulatory and Other Approvals.....	26
Liquidity, Cash Flow and Capital Availability Risks	26
Commodity Price and Supply Risks	27
Usage Risks.....	27
Regulatory Risks.....	27
Facility and Insurance Risks	28
Environmental and Safety Risks	28
Derivatives Risk.....	29
Human Resources Risks	29
Aboriginal Matters	29
Share Price Volatility	29
DIVIDENDS	30
DESCRIPTION OF CAPITAL STRUCTURE	30
Common Shares	30
Cumulative Redeemable Junior Preferred Shares.....	30
6 ³ / ₄ % Cumulative Redeemable Preferred Shares	31
Ratings	31
MARKET FOR SECURITIES	32
LEGAL PROCEEDINGS.....	32
DIRECTORS AND OFFICERS.....	33
Directors.....	33
Officers	34
Audit Committee.....	35
INTERESTS OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS	36
TRANSFER AGENT	37
EXPERTS.....	37
ADDITIONAL INFORMATION	38
SCHEDULE "A"	39

GLOSSARY

In this annual information form, *gigajoule* (GJ) is equivalent to 947,817 British thermal units, *terajoule* (TJ) means one thousand GJ and *petajoule* (PJ) means one million GJ. One GJ is equivalent to approximately 0.9225 Mcf of gas. *Mcf* means one thousand cubic feet and *MMcf* means one million cubic feet. 10^3m^3 means one thousand cubic metres. In volumetric units, 1000 cubic metres is equivalent to 35.30 thousand cubic feet.

SPECIAL NOTE REGARDING FORWARD LOOKING STATEMENTS

Certain information provided and incorporated by reference in this annual information form may contain forward-looking statements that are subject to risks and uncertainties. Although the Company, as defined below, believes any such forward-looking statements are based on reasonable assumptions, no assurance can be given that every objective will be reached. The forward-looking statements may involve known and unknown risks, uncertainties and other factors which may cause the actual results, performance or achievements of the Company to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such factors 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. Forward-looking statements, which involve assumptions and describe the Company's future plans, strategies and expectations, are generally identifiable by the words "may", "will", "should", "expect", "anticipate", "estimate", "believe", "intend" or "project" or the negative of these words or other variations of these words or comparable terminology. For further discussion see the section entitled "Risk Factors".

Any forward-looking statement speaks only as of the date on which it is made and the Company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances after the date on which the statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time and it is not possible for the Company to predict which will arise after the date of this annual information form.

THE COMPANY

Corporate Structure

Pacific Northern Gas Ltd. (the "Company") was incorporated under the laws of British Columbia as a private company on October 28, 1965 and was converted to a public company on November 4, 1968. The head office of the Company is located at Suite 950, 1185 West Georgia Street, Vancouver, British Columbia, V6E 4E6 and its principal operating office is at 2900 Kerr Street, Terrace, British Columbia.

Pacific Northern Gas (N.E.) Ltd. (“Pacific Northern (N.E.)”) was formed under the laws of British Columbia on June 30, 1999 by the amalgamation of Pacific Northern Gas (N.E.) Ltd., Centra Gas Fort St. John Inc. and Peace River Transmission Company Limited. Pacific Northern (N.E.) is a wholly owned subsidiary of the Company with its main operating offices at 1208 – 102nd Avenue, Dawson Creek and 10016 – 104 Street, Fort St. John, British Columbia. PNG Marketing Ltd. (currently inactive) was incorporated under the laws of British Columbia on October 17, 1986 and is a wholly owned subsidiary of the Company. Pacific Northern Gas Transition Ltd. (currently inactive) was incorporated under the laws of British Columbia on January 28, 2004 and is a wholly owned subsidiary of the Company.

General Development of the Business

The Company owns and operates a natural gas transmission and distribution utility operating within the west-central portion of northern British Columbia (“Western region”). Pacific Northern (N.E.) owns and operates a distribution utility in the northeast part of British Columbia (“Northeast region”). The utilities are separate stand-alone systems and both are regulated by the British Columbia Utilities Commission (“Commission”).

The business of the Company was essentially static in 2002. In 2003 the Company’s financial position was strengthened by the establishment of a new operating and hedge line of credit, allowing the Company to improve its hedging program. Toward the end of 2004, the Company negotiated a new credit facility which included a \$20 million operating line and a \$15 million hedge facility, with a new lender on more favourable terms. In addition, in 2003 the Commission approved a rate stabilization adjustment mechanism that mitigates the risk in forecasting deliveries. This mechanism allows the Company to record the after-tax revenue variances arising from differences between actual and forecast sales volumes for residential and small commercial customers in a deferral account for collection or refund in future rates.

In early 2004 the Company entered into a new ten year transportation service agreement with one of its large industrial customers starting January 1, 2004. The agreement was approved by the Commission in July, 2004.

High natural gas prices and weak economic conditions faced by the Company’s customer base in the Western region continue to reduce the quantity of gas sold and delivered to the Company’s customers in that area. The economy in the Northeast region is growing as a result of activity in the oil and gas exploration sector, which is reflected in customer additions in that area.

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.

Tricor Acquisition (STP) Inc., a subsidiary of Tricor Pacific Capital, Inc. (“Tricor”) acquired the Company’s Class A non-voting and the Class B voting common shares held by Westcoast Energy Inc., effective December 18, 2003. In connection with the acquisition, all of the Company’s Class

A and Class B common shares were reclassified as one class of common shares with one vote per share. As a result of the acquisition, Tricor owns 37 percent of the outstanding common shares of the Company.

The Company submitted an application to the Commission in January, 2004 seeking approval to recapitalize under an income trust ownership structure. This application was denied by the Commission in a decision released in July, 2004. Management of the Company reviewed the reasons for the denial by the Commission of its initial application to convert to an income trust and concluded the Commission's concerns could and should be addressed in the new application. The Company continues to believe that an income trust structure would significantly improve the financial stability of the Company and be in the best interests of all stakeholders.

The Company's strategic focus in 2005 will be to enhance shareholder value by continuing to pursue a recapitalization under an income trust ownership structure. The Company filed a new application for approval to convert to an income trust structure on December 17, 2004 together with an application for new customer rates effective January 1, 2005. The applications are subject to review and approval by the Commission. The income trust application will be reviewed at a public hearing before the Commission in mid May 2005. A decision by the Commission is expected to be rendered by the third quarter of 2005. The implementation of the income trust structure would also require the approval of the shareholders of the Company, court approval and acceptable market conditions. No assurances can be given by the Company that the required approvals will be obtained.

On March 11, 2005, at the request of Tricor Acquisition (STP) Inc. ("Tricor"), the Company filed a preliminary prospectus with the securities regulators in each province of Canada for the public offering of 1,338,477 common shares of the Company currently owned by Tricor. The common shares offered by Tricor represent 37% of the Company's currently outstanding common shares and represent 100% of Tricor's interest in the Company. On March 15, 2005, the Company, Tricor and certain underwriters entered into an underwriting agreement whereby the underwriters agreed to purchase the common shares offered by Tricor at a price of \$19.40 per common share, for total gross proceeds of approximately \$26 million. The prospectus had also provided for the public offering of up to 69,229 additional common shares owned by certain executive officers of the Company, but such officers subsequently elected not to participate in the offering and to retain their shares. The Company is not selling any newly issued common shares as part of the offering and will not receive any proceeds from the sale of the common shares by Tricor. In addition, Tricor will pay the expenses relating to the offering. Closing of the offering is expected to occur in April, 2005.

BUSINESS OF THE COMPANY

Overview

The Company's Western region extends from Summit Lake to Prince Rupert and Kitimat. The Northeast region includes Tumbler Ridge, Dawson Creek, Fort St. John and the surrounding areas. The Company also operates a small propane vapour distribution system in Granisle, British Columbia.



The Company supplies gas to approximately 39,300 residential, commercial and industrial customers. The Company has four large industrial customers: Methanex Corporation (“Methanex”), West Fraser Mills Ltd. (“West Fraser”), Alcan Smelters and Chemicals Ltd. (“Alcan”) and British Columbia Hydro and Power Authority (“BC Hydro”). These four customers accounted for 75% of total gas deliveries and 33% of the Company’s operating margin during 2004.

The Company’s combined rate base for 2004, as approved by the Commission, was approximately \$167 million.

Gas distributed by the Company to its residential and commercial customers and to certain industrial customers in 2004 was purchased under various agreements with gas producers and other suppliers. Most of the Company’s industrial customers satisfy their gas requirements by purchasing gas directly from producers or other suppliers and contracting with the Company for the transportation of that gas through the Company’s pipeline systems. Accordingly, all of the firm gas requirements of the Company’s large industrial customers and approximately three-quarters of the firm gas requirements of the Company’s small industrial customers are met through direct gas supply arrangements. Since the Company earns income from the transportation and distribution of gas and not from the sale of gas as a commodity, it is not adversely affected by direct gas supply arrangements entered into by its customers.

The Company’s natural gas distribution business is seasonal, with higher sales in the colder winter months and lower sales in warmer months as a result of a substantial portion of the gas it delivers 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 generally incurs losses in the other two quarters.

Western Region

Transmission Pipeline System

The Company's transmission pipeline system in the Western region connects with the British Columbia pipeline system operated by Westcoast Energy Inc., doing business as Duke Energy Gas Transmission ("Duke Energy"), near Summit Lake, British Columbia, and extends 587 kilometres to the west coast of British Columbia at Prince Rupert. The pipeline between Summit Lake and Terrace has been partially paralleled, or looped, with a second line to increase throughput capacity. The Company also owns and operates over 300 kilometres of lateral transmission pipelines extending into the various communities served by the Company, the most significant being dual lines extending approximately 57 kilometres into Kitimat.

Five compressor units maintain pressure on the Company's transmission pipeline system: two located at Summit Lake and one each at Vanderhoof, Burns Lake and Telkwa. The total installed rating of the compressor units is 16,120 kilowatts (21,610 horsepower). The sustainable capacity of the transmission pipeline system, with the present compressor and looping configuration, is approximately $3\,260\,10^3\text{m}^3$ (115 MMcf) per day.

Distribution System and Franchise Agreements

The Company owns and operates natural gas distribution facilities to deliver gas from its pipeline system to homes and businesses in the various communities located throughout the Western region. The Company's Western region distribution system is comprised of approximately 1,180 kilometres of distribution pipelines.

The Company currently has exclusive franchise agreements with the municipalities of Prince Rupert, Port Edward, Kitimat, Terrace, Smithers, Burns Lake, Houston and Vanderhoof, entitling it to supply and distribute natural gas within those municipalities. The customers in these municipalities represent approximately 75% of all customers in the Western region. Each of the franchise agreements has an initial term of 21 years, expiring in 2011 (except in the case of Port Edward, where the agreement expires in 2010, and Prince Rupert, where the agreement expires in 2015), and is renewable at the option of either party for a further term of 21 years.

The Company also has operating agreements with the municipalities of Fort St. James and Telkwa that entitle it to install and operate gas distribution facilities in those municipalities. The initial term of each of these operating agreements has expired, and the Company is operating within ten year renewal terms which expire in 2009 and 2011, respectively. Each operating agreement provides for an unlimited number of ten year renewal terms, which take effect automatically on the expiry of the preceding renewal term. If the parties cannot agree on alterations to an operating agreement for a renewal term, the Commission may determine such alterations. In the Village of Fraser Lake, the Company is operating under a franchise agreement which the Company is proceeding to file for approval with the Commission.

Under all of the municipal franchise and operating agreements, the Company is required to pay the municipality an annual fee on gas sales within the municipality equal to 3% of the Company's gross revenue from sales to residential and commercial customers and 3% of the gross revenue from the sale of the first 328 000 GJ (approximately 300 MMcf) per year to any industrial customer.

The communities served by the Company's distribution system within its Western region had a total population of approximately 77,000 at December 31, 2004.

Northeast Region

Transmission and Distribution Facilities

The Company's pipeline system in the Northeast region serves the Fort St. John and Dawson Creek area through connections with the Duke Energy pipeline system at several locations. The Company's system also connects with a pipeline owned by Canadian Natural Resources Limited ("CNRL") in two locations to obtain supply for the Fort St. John area, and with a producer's pipeline and the Duke Energy pipeline system near Chetwynd, British Columbia to serve the Tumbler Ridge area. The Company's entire system in the Northeast region consists of approximately 160 kilometres of transmission lines, 1,490 kilometres of distribution lines and a gas processing plant near Tumbler Ridge with a capacity of $120 \times 10^3 \text{ m}^3$ per day.

Franchise Agreements

The Company has exclusive franchise agreements with the cities of Dawson Creek and Fort St. John for 21-year terms, expiring in 2014 and 2018, respectively, as well as an operating agreement with the Village of Pouce Coupe which expires in 2016. The agreements provide for payment of a 3% fee on gross revenues from sales of gas to residential, commercial, public and institutional customers and 3% of the gross revenue from the sale of the first 328 000 GJ per year to any industrial customer. The Company operates its gas distribution facilities in the Tumbler Ridge area pursuant to a certificate of public convenience and necessity issued by the Commission. No franchise fees are payable to the municipality of Tumbler Ridge.

The franchise agreement with the City of Dawson Creek and the operating agreement with the Village of Pouce Coupe are renewable for a further term of 21 years at the option of either party. The franchise agreement with the City of Fort St. John gives the municipality the right to purchase the distribution system within the municipality on expiry of the franchise agreement, at the fair market value of the assets as a going concern.

The communities served by the Company's distribution system in its Northeast region had a total population of approximately 47,000 at December 31, 2004.

Properties

Substantially all of the Company's transmission lines and lateral lines are located across Crown land or privately owned property under rights-of-way granted by the Crown or the owners in perpetuity or for so long as they are used for pipeline purposes. Approximately three kilometres of main pipelines and approximately nine kilometres of lateral transmission pipelines cross

reserves established under the *Indian Act* (Canada), for which the Company has appropriate land rights. Within all the municipalities in which the Company distributes gas, distribution lines occupy municipal streets and lanes by authority granted to the Company under franchise or operating agreements or other regulatory approvals. River, highway and railway crossings have generally been constructed pursuant to orders or permits from appropriate authorities or owners. Compressor and metering stations are principally located on land owned by the Company in fee simple. The Company owns its local offices in Terrace, Prince Rupert, Kitimat, Burns Lake, Smithers, Dawson Creek, Tumbler Ridge and Fort St. John and leases office space in a number of other communities in its service area and in Vancouver.

All of the property and assets of the Company and Pacific Northern (N.E.) are subject to the lien of a deed of trust and mortgage dated as of April 15, 1982 between the Company and Computershare Trust Company of Canada, as trustee, as amended and supplemented from time to time, under which the Company's secured debentures have been issued.

Gas Sales and Transportation

Total natural gas deliveries were 39.0 PJ in 2004 compared with 36.6 PJ in 2003. Deliveries to large industrial customers increased 9.6% from 2003 to 2004 as a result of operations returning to normal following temporary shutdowns in 2003 by the Company's two largest industrial customers. These shutdowns included a four month labour dispute at West Fraser's linerboard and kraft paper mill in Kitimat and a five week maintenance shutdown at the Methanex methanol/ammonia facility in Kitimat.

Deliveries to residential and small commercial customers declined in 2004 by 6% from 2003 levels, which can be partially attributed to the weather being approximately 5% warmer, measured in heating degree days, in 2004 than in 2003.

The following table sets out, by customer category, certain information relating to the Company's gas sales and deliveries for the past three years:

	<u>2004</u>	<u>2003</u>	<u>2002</u>
Deliveries (in terajoules):			
Residential	3 279	3 464	3 503
Commercial	2 715	2 909	2 967
Small industrial.....	3 736	3 589	3 805
Large industrial.....	29 241	26 676	29 188
Total energy delivered	<u>38 971</u>	<u>36 638</u>	<u>39 463</u>
Customers at Year End:			
Residential	34,242	34,078	34,251
Commercial	4,993	4,978	4,941
Small industrial.....	52	46	58
Large industrial.....	4	4	4
Total number of customers	<u>39,291</u>	<u>39,106</u>	<u>39,254</u>
Revenue (Dollars in thousands):			
Sales Revenue			
Residential	\$37,627	\$38,815	\$30,204
Commercial	26,488	28,196	22,213
Small industrial.....	5,746	6,840	7,151
Large industrial			
Methanex	—	—	—
West Fraser	—	—	—
Skeena	—	—	—
Alcan	4,997	5,026	3,292
BC Hydro.....	35	—	—
Off system sales	43,949	33,403	18,763
Total sales revenue.....	<u>118,842</u>	<u>112,280</u>	<u>81,623</u>
Cost of sales.....	<u>(88,954)</u>	<u>(84,417)</u>	<u>(56,820)</u>
Operating margin from sales	<u>29,888</u>	<u>27,863</u>	<u>24,803</u>
Transportation Revenue			
Residential.....	—	—	—
Commercial	197	182	182
Small industrial	2,839	2,705	2,328
Large industrial			
Methanex	12,191	12,344	20,589
West Fraser.....	2,435	3,374	3,091
Skeena	—	1,675	—
Alcan	672	577	541
BC Hydro	68	62	38
Off system sales	—	—	—
Total transportation revenue / operating margin from transportation.....	<u>18,402</u>	<u>20,919</u>	<u>26,769</u>
Other Revenue	<u>511</u>	<u>528</u>	<u>671</u>
Total operating margin	<u>\$48,801</u>	<u>\$49,310</u>	<u>\$52,243</u>

Note:

- (1) References to “operating margin” are to operating revenues less cost of sales. Operating margin is not a recognized measure under GAAP and does not have a standardized meaning prescribed by GAAP. Therefore, operating margin may not be comparable to similar measures presented by other issuers. Readers are cautioned that operating margin should not replace revenues as a measure of activity..

Large Industrial Customers

Overview

The Company has transportation service agreements with Methanex, West Fraser and Alcan. The Company delivers gas to its other large industrial customer, BC Hydro, under an interruptible sales and service agreement for standby power generation at BC Hydro's facility in Prince Rupert.

The agreements with Methanex, West Fraser and Alcan each provide for a specified contract demand, which is the maximum volume of gas the Company is obligated to deliver each day on a firm basis, and a specified minimum monthly charge, stated as a percentage of the monthly contract demand volume.

Methanex

Under the terms of its agreement with Methanex, the Company provides firm gas transportation service to Methanex's methanol/ammonia complex in Kitimat, British Columbia. The agreement specifies a daily contract demand of 1 614.6 10³m³ (57.0 MMcf) and a minimum monthly charge equal to 100% of the monthly contract demand volume at a firm toll of \$0.50 per GJ over the term of the agreement. The contract also provides for interruptible transportation of volumes in excess of the contract demand at a toll of \$0.32 per GJ. In addition, Methanex supplies a portion of the Company's internal gas requirements equal to 4% of deliveries to Methanex. The contract also includes a profit-sharing mechanism during periods of high methanol prices and relatively low gas prices. The profit-sharing mechanism did not result in any additional revenue to the Company in 2002, 2003 or 2004. Deliveries to Methanex in 2004 accounted for approximately 67% of the volumes delivered by the Company and approximately 25% of the Company's operating margin.

The agreement with Methanex expires in October 2009, but Methanex may terminate its obligations under the agreement with six months' notice and payment of a buy-out amount to the Company on the effective date of the termination. The buy-out payment is approximately equal to the net present value of future firm contract payment obligations, net of the Company's avoidable costs if Methanex were no longer operating. The buy-out payment was set at \$30 million as at November 1, 2004 and reduces monthly to \$14 million as at November 1, 2007; thereafter, the buy-out payment reduces by \$583,333 per month.

Methanol and ammonia are subject to international commodity price fluctuations. As a result, the Company's gas deliveries to Methanex have been and may in the future be affected by the ability of the Kitimat facility to remain profitable during sustained periods of low commodity prices. On July 1, 2000 Methanex shut down the facility for 12 months in response to low methanol prices. The Company considers that there is a significant risk that Methanex will terminate its agreement with the Company in accordance with its terms prior to its expiry or not renew its contract with the Company when it expires in October 2009. See "Risk Factors".

West Fraser

Under the terms of its agreement with West Fraser, the Company provides firm gas transportation service to West Fraser's linerboard and kraft paper mill in Kitimat, British Columbia. The agreement specifies a daily contract demand volume of 170.0 10³m³ (6.8 MMcf) and a minimum monthly charge, equal to 100% of the monthly contract demand volume. A toll of \$0.85 per GJ applies for the first five years of the term of the agreement, ending on December 31, 2008. For the second five years of the term, the toll is \$0.85 per GJ adjusted by 50% of the change in the British Columbia Consumer Price Index over the five year period ending December 31, 2008. The contract also provides for interruptible transportation of volumes in excess of the contract demand at a toll of 1.15 times the firm toll. In addition, West Fraser supplies a portion of the Company's internal gas requirements equal to 4% of deliveries to West Fraser. The agreement was approved by the Commission in July, 2004 with effect as of January 1, 2004 and resulted in a toll approximately 30% lower than that previously in effect. During 2004, deliveries to West Fraser accounted for approximately 6% of the Company's total gas deliveries and 5% of operating margin.

The agreement with West Fraser expires in December 2013, but West Fraser may terminate its obligations under the agreement with six months' notice and payment of a buy-out payment to the Company on the effective date of the termination. The buy-out payment was set at \$10,500,000 as of January 1, 2005 and reduces monthly to \$1,775,000 as of January 1, 2013. Moreover, if West Fraser has permanently shut down the Kitimat mill or has commenced the process of permanently shutting down the Kitimat mill prior to January 1, 2009 then West Fraser may terminate the agreement with no buy-out payment, effective January 1, 2009 by giving the Company at least six months' notice of termination prior to January 1, 2009. West Fraser's obligation to pay the minimum monthly charge will continue in effect until the Kitimat mill is permanently shut down. If the permanent shutdown is not completed by December 31, 2009, then the agreement with the Company will continue in force until the original expiry date of December 31, 2013. See "Risk Factors".

Alcan

Under the terms of its agreement with Alcan, the Company provides firm gas transportation service to Alcan's Kitimat aluminium facility, with a toll established by the Commission from time to time. The agreement specifies a daily contract demand volume of 30.8 10³m³ (1.1 MMcf) and a minimum monthly charge equal to 85% of the monthly contract demand volume multiplied by the firm transportation toll. The agreement also provides for interruptible sales of gas to Alcan.

The initial term of the agreement ended November 1, 2004, but the agreement automatically continues in effect from contract year to contract year unless either party gives twelve months' notice of termination. No termination notice has been given.

During 2004, deliveries to Alcan accounted for 3% of the Company's total gas deliveries and 2% of operating margin. Alcan has produced aluminium for export from its Kitimat facility since 1952.

BC Hydro

The Company delivers gas to its other large industrial customer, BC Hydro, under an interruptible sales and service agreement for electric power generation at BC Hydro's facility in Prince Rupert. This generation plant has typically been used by BC Hydro as a stand-by facility. Deliveries of 21.6 TJ in 2004 were utilized to maintain the facility in a ready to operate mode. These deliveries represented approximately 0.02% of operating margin.

New Skeena Forest Products Inc.

Prior to 2001, Skeena Cellulose Inc. ("Skeena") was the Company's second largest customer. Skeena owned and operated a pulp mill in Prince Rupert and certain sawmill facilities in the region. In 2001, Skeena shut down the pulp mill and sought protection under the *Companies' Creditors Arrangement Act* (the "CCAA"). New Skeena Forest Products Inc. ("New Skeena") purchased the assets of Skeena pursuant to a restructuring approved under the CCAA. The Company's 2003 rate application to the Commission assumed a prospective transportation contract with New Skeena for service to the pulp mill in Prince Rupert. It was expected that the pulp mill would operate for six months during 2003. The restructuring was not successful and the plant failed to open in 2003. As a result, the Company recorded deferred charges of \$1.7 million, before tax, in its Industrial Customer Deliveries Deferral Account. These charges are being amortized in rates and collected from customers over a three year period beginning in 2004. Subsequently, New Skeena obtained protection under the CCAA but was unsuccessful in its efforts to secure new financing to support a restructuring plan. The pulp mill has not reopened and a bankrupt trustee is now in the process of liquidating the assets of New Skeena.

Natural Gas Supply

All of the Company's residential customers, most of its commercial customers and a number of its smaller industrial customers continue to rely on the Company for arrangement of their gas supply, and pay tariffs which include the Company's gas supply commodity and delivery costs. The commodity cost of gas is passed through to customers in rates and subsequent rate adjustments, after approval by the Commission.

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.

To meet the requirements of its core market customers, natural gas is purchased by the Company under various gas purchase contracts. Contracted gas that is surplus to the requirements of these customers in non-peak periods may be sold either on an interruptible basis to industrial customers or be sold to other purchasers who are not the Company's transmission or distribution customers ("off system sales").

Natural gas is purchased at prevailing market prices and passed through to customers without mark-up by the Company. 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 and fixed price supply contracts under a gas price management plan that is filed with the Commission on an annual basis.

Virtually all of the gas purchased by the Company from its gas suppliers is taken from the pooled gas stream available from the Duke Energy pipeline system. This includes all of the supply to the Company's transmission line serving its Western region service area and approximately three-quarters of the supply for the Fort St. John and Dawson Creek service areas in the Northeast region.

In addition to the supply from the Duke Energy system, the Fort St. John system incorporates two interconnections with CNRL's West Stoddart Pipeline, providing 38% of the system's requirements. In Dawson Creek, approximately 8% 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.

Approximately 61% of gas purchased by the Company in 2004 was purchased from CanWest Gas Supply Inc. ("CanWest") under a contract which expires October 31, 2005. Other supplies included purchases under seasonal and spot arrangements. The Company will contract for adequate gas supplies in the ordinary course following expiry of the CanWest agreement.

Customer Additions

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

In 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 policy 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 region. Also, with the exception of the Northeast region, local economies have been depressed as a result of uncertainty concerning future industrial activity levels. This lower level of customer additions is expected to prevail in the foreseeable future.

Government Regulation

General

The Company is subject to regulation under the *Utilities Commission Act* (British Columbia) (the “Utilities Act”). Pursuant to the Utilities Act, the Commission regulates the business of public utilities, including the construction and operation of major facilities, the issuance of securities, 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 such rates reflect a fair and reasonable charge for service of the nature and quality furnished by the Company to its customers, and that such rates are sufficient to yield the Company a fair and reasonable compensation for its services or a fair and reasonable return upon the value of its property.

The Company is also subject to regulation under the *Pipeline Act* (British Columbia) in respect of the construction, operation and maintenance of its transmission pipeline facilities.

Rate Regulation

The Company’s rates are determined by the Commission on a fixed rate method, under which rates are set on the basis of annual forecasts of both the cost of service and throughput for the Company’s transmission and distribution system. The cost of service consists of the cost of purchased gas and the cost of transporting all gas delivered through the Company’s system, including operating, maintenance and administrative expenses, depreciation of facilities, income and other taxes and a return on rate base. Rate base is composed of the depreciated book value of plant in service, plus unamortized deferred charges, plus allowance for working capital, less deferred income taxes. The rate base is approved annually by the Commission for rate making purposes, including approval of annual capital additions forecast by the Company. Forecast capital additions are usually approved as applied for by the Company with minor modifications. If the actual cost of forecast capital additions exceeds the amount approved by the Commission, the excess cost may be subject to a prudence review by the Commission depending on the extent actual costs exceed the amount approved by the Commission. 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.

A key component of the cost of capital is the after-tax return on the common equity component of the capital structure (the “ROE”). The Commission uses a formula to determine, on an annual basis, the ROE applicable to a low risk benchmark utility based on forecast long term Government of Canada bond rates, plus 350 basis points. The Company’s risk profile is compared by the Commission to the low risk benchmark utility to determine the Company’s utility-specific risk premium relative to the ROE applicable to the low risk benchmark utility. The Company’s utility-specific risk premium is then added to the low risk benchmark utility risk premium to determine the ROE which the Company is allowed to include in rates each year. The Company’s ROE is therefore subject to variations in forecast long term Canada bond rates. The ROE changes on a one to one basis for changes in the long term Canada bond rates below six percent. For changes to the long term Canada bond rates above six percent, the ROE changes by 80% of the change. The ROE is set by the Commission in November each year to be applied in the following calendar year.

The Commission has approved a number of deferral accounts for the Company to record costs and revenues for various items for recovery from customers, or refund to customers, over a future time period. The general purpose of a deferral account is to keep the Company or its customers whole in respect of the subject matter of the deferral account. Two main deferral accounts apply to all divisions of the Company:

- Gas Cost Variance Account (“GCVA”) – The commodity cost of gas included in customer rates is based on a forecast of the gas market prices the Company expects to pay to gas suppliers over a 12 month period. The difference between the forecast gas cost the Company charges its customers and the actual gas cost incurred by the Company is recorded by the Company in the GCVA. The balance in this account is reviewed by the Company and the Commission every quarter. If actual gas costs exceed forecast gas costs, the difference will be recovered from customers by an increase in future rates. If actual gas costs are lower than forecast gas costs, the difference will be refunded to customers through a reduction in future rates. In this way, customers, over time, pay the same cost for gas as is paid by the Company.
- Rate Stabilization Adjustment Mechanism (“RSAM”) - the Company forecasts the revenue it will receive from customers based on an annual forecast of gas deliveries to customers. As it is not possible to forecast deliveries to customers with complete accuracy for a variety of reasons, including the effect of weather on gas consumption, the Company is allowed by the Commission to record the difference between forecast and actual revenue recovery from residential and small commercial customers in the RSAM deferral account. If actual deliveries exceed forecast deliveries, the resulting revenue difference will be recorded in the RSAM deferral account and refunded to customers in future rates. If actual deliveries are less than forecast deliveries, the resulting revenue difference will be recorded in the RSAM deferral account and recovered from customers in future rates.

Revenue requirements applications for three service areas (the Western region service area and two service areas in the Northeast region) are submitted to the Commission, generally on an annual basis. The Northeast region contains two divisions for rate making purposes. One division comprises the Fort St. John/Dawson Creek service area, and the other division the Tumbler Ridge service area. 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. The 2004 and 2005 revenue requirements applications and related Commission decisions for each service area are summarized in the following sections.

Western Region

In November 2003, the Company filed a revenue requirements application with the Commission for approval of new rates to take effect January 1, 2004. The application for 2004 was considered by the Commission through a public hearing process.

The Commission issued its decision on July 29, 2004. The 2004 allowed rate of return on common equity for the Western region was 9.80%, based on a deemed common equity

component of 36%. The allowed rate of return on common equity included a 65 basis point premium over the low risk benchmark utility rate of return.

The RSAM deferral account was approved by the Commission in 2003. In general, the RSAM deferral balance at the end of each year is recovered from or refunded to customers over the following three-year period. During 2004, an after tax amount of approximately \$0.9 million was credited to income in respect of this deferral for the Western region.

For 2004, the Commission continued its direction to defer the difference between actual operating margin from deliveries to Methanex, West Fraser, Alcan and BC 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 GCVA. 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 GCVA balance.

In 2004, the net book value of a propane air plant which is no longer in service was removed from property, plant and equipment and an after tax amount of approximately \$0.8 million was transferred to a deferral account for proposed future recovery from customers over a period of twenty years commencing in 2005. The ultimate realization of the amount transferred to the deferral account is subject to a future decision of the Commission.

The 2005 revenue requirements application for the Western region 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 increase in the gas delivery charge was due to the Company seeking approval of an increase in common equity from the deemed 36% approved by the Commission in 2004 to the Company's actual common equity of approximately 51%. The Commission approved interim gas delivery charge increases effective January 1, 2005 applying the existing deemed 36% common equity ratio. The final gas delivery rates for 2005 will be determined under a review process to be determined after the Commission releases its decision on the Company's application to convert to an income trust ownership structure. See "- Application to Commission to Convert the Company to an Income Trust Structure" below.

The Commission accepted the gas supply commodity charge increases applied for by the Company, effective January 1, 2005. The final gas supply commodity charges for the first quarter of 2005 are approximately 10% higher than those embedded in rates as of December 31, 2004.

The forecast 2005 residential and commercial deliveries contained in the 2005 revenue requirements application are approximately 6% higher than actual gas deliveries to those customer classes in 2004. Deliveries to small industrial customers are projected to be approximately 9% lower in 2005 compared to actual gas deliveries in 2004.

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

Northeast Region

Tumbler Ridge Division

In July 2004, the Commission issued its decision on the Tumbler Ridge division 2004 revenue requirements application, following a written hearing. The 2004 allowed rate of return on common equity was 9.80%, based on a deemed common equity component of 36%. The allowed rate of return on common equity included a 65 basis point premium over the low risk benchmark utility rate of return.

During 2004, \$77,000, net of income taxes, was credited to income in respect of the RSAM deferral for the Tumbler Ridge division.

The Tumbler Ridge revenue requirements application for 2005 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 Commission approved interim delivery charges effective January 1, 2005 at the level applied for, which includes a deemed common equity of 36% and an allowable return on common equity of 9.68% for 2005. The resulting rate increases were approximately 3% 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 2005 revenue requirements application. A decision by Commission is expected in the second quarter of 2005.

Fort St. John/Dawson Creek Division

In July 2004, the Commission issued its decision on the Fort St. John/Dawson Creek division 2004 revenue requirements application, following a written hearing. The 2004 allowed rate of return on common equity was 9.55% for the Fort St. John/Dawson Creek division, based on a deemed common equity component of rate base of 36%. The allowed rate of return on common equity included a 40 basis point premium over the low risk benchmark utility rate of return.

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 GCVA 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 GCVA balance.

During 2004, \$256,000, net of income taxes, was credited to income in respect of the RSAM deferral for the Fort St. John/Dawson Creek division.

The Fort St. John/Dawson Creek revenue requirements application for 2005 was filed in December 2004. The application sought Commission approval to increase both the gas delivery charge component of 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% and an allowable return on common equity of 9.43% for 2005. The gas supply commodity charge increases received final approval. In total, the rate increases effective January 1, 2005 result in an increase in interim rates for residential and small commercial customers of approximately 5% and 4% respectively, compared to rates in effect as of December 31, 2004.

The Commission is conducting a written hearing process for the 2005 revenue requirements application. A decision by Commission is expected in the second quarter of 2005.

Rate Base and Common Equity

The following table summarizes, for each of the Company's three service areas, the rate base, common equity component of rate base and the after tax rate of return on common equity approved by the Commission for the three years ended December 31, 2004:

	Years ended December 31		
	2004	2003	2002
	<i>(Dollar amounts in thousands)</i>		
Western region:			
Rate base.....	\$135,488	\$136,037	\$136,983
Common equity component.....	36.0%	36.0%	36.0%
Allowed return on common equity	9.80%	10.17%	9.88%
Fort St. John/ Dawson Creek division:			
Rate base.....	\$30,521	\$28,219	\$26,281
Common equity component.....	36.0%	36.0%	36.0%
Allowed return on common equity	9.56%	9.82%	9.60%
Tumbler Ridge division:			
Rate base.....	\$1,043	\$1,166	\$1,180
Common equity component.....	36.0%	36.0%	36.0%
Allowed return on common equity	9.80%	10.07%	9.89%

Application to Commission to Convert the Company to an Income Trust Structure

Background

On January 30, 2004 the Company filed an application with the Commission seeking approval to convert to an income trust ownership structure. The decision to seek approval to convert to an income trust structure was primarily based on the following circumstances and their impact on the Company's liquidity and access to capital:

- In July 2000, Methanex shut down its methanol plant at Kitimat for 12 months during a period of low methanol prices. Methanex was then, and is currently, the Company's largest customer, and at the time of the shutdown accounted for

approximately 70% of the Company's total gas throughput and 40% of its total operating margin.

- Although the Methanex plant resumed operation in 2001 and the Company entered into a new contract with Methanex in 2002, the continuing significance of Methanex as a customer (accounting for approximately 25% of the Company's operating margin in 2004), coupled with the fact that the new contract expires in 2009 and can be terminated by Methanex before that date, has precluded access by the Company to traditional institutional lenders as a source of long term debt. Since 2002, the Company has had access only to short term debt which cannot be used to refinance existing long term debt.
- The Company is accordingly relying on operating cash flow to fund capital expenditures and amortization of long term debt, as well as to pay dividends.
- The Company has significant near and medium term needs to access capital markets. In particular, the Company needs to access long term debt markets to refinance its maturing long term debt. Over the next ten years the Company must refinance approximately \$46 million of long term debt, including \$4.4 million of debt in 2005 and \$4.9 million per year over the four year period from 2006 to 2009, inclusive.

Given these circumstances, the Company concluded in early 2003 that reorganizing its business under an income trust ownership structure would be the best means of addressing the Company's capital requirements on a long term basis. The Company believes one of the primary advantages of the income trust structure is that it would allow the Company to reduce its long term secured debt significantly, and replace that secured debt with long term subordinate debt advanced by the income trust using proceeds from an initial public offering of trust units. This would improve the Company's financial flexibility and access to capital without having to increase rates to customers.

Initial Decision, Subsequent Application and Approval Requirements

On July 29, 2004 the Commission issued a decision denying the Company's initial application to convert to an income trust structure, citing concerns over the requirement to deem a common equity component higher than the proposed income trust's level of equity, as well as requirements to deem income tax expenses for rate making purposes.

The Company reviewed the Commission decision and concluded the Commission's concerns could be addressed in a new application. In December 2004, the Company filed a new application with the Commission for approval to convert to an income trust structure. The Company believes the new application addresses the concerns raised by the Commission in its denial of the first application. In particular, the new application requests that the Commission set customer rates using the actual capital structure of the proposed income trust rather than a deemed capital structure.

An oral public hearing on the Company's application is scheduled to commence on May 10, 2005.

In addition to approval by the Commission, the conversion to an income trust structure will require:

- approval by 75% of votes cast at a meeting of the shareholders of the Company to approve a plan of arrangement under the *Business Corporations Act* (British Columbia);
- court approval of the plan of arrangement; and
- agreement with the Company's debenture holders to allow the Company to redeem approximately \$40 million of its outstanding debentures on acceptable terms and conditions.

The plan of arrangement is also expected to be conditional upon the completion by the proposed income trust of an initial public offering of units, the proceeds of which would be used to redeem a portion of the outstanding debentures and all of the Preferred Shares, and to pay conversion and transaction expenses. The Company can give no assurances that the required approvals will be obtained, that there will be acceptable market conditions for the proposed income trust's initial public offering or that the conversion by the Company to an income trust structure will be completed.

Engineering and Operations

In-Line Inspection

The Company has processes in place to monitor the ongoing integrity of its transmission pressure pipeline to ensure protection of the public and the environment by demonstrating that all transmission pipelines are suitable for continued safe and reliable service. A key aspect of these processes focuses on the internal inspection of the pipeline using in-line inspection tools and subsequent repair activities that arise from the information gathered.

The Company began implementing in-line inspection programs on its transmission pipeline in 1989. The 2004 in-line inspection activity involved running the inspection tool through three different sections of twelve-inch line totalling approximately 45 kilometres in length. The results of these inspections were favourable. The Company intends to continue its in-line inspection program on an annual basis in 2005 and into the foreseeable future.

Compressor Control Systems

Installation of a programmable logic controller-based system at the Burns Lake compressor station was completed in 2004. The new system offers more reliable control and a greater level of operational flexibility, while allowing for remote control and troubleshooting of the compressor unit. As of December 31, 2004, all of the Company's compressor control systems had been upgraded with these systems.

Khyex River Slide

On November 28, 2003, a massive debris slide 55 kilometres east of Prince Rupert ruptured a section of the eight-inch high-pressure transmission pipeline. A temporary line was installed in order to restore service to the affected customers. The temporary line remains in service while the Company waits for the soil in the area of the slide to stabilize. In accordance with Commission approvals, the costs of the temporary repair were deferred and are to be collected from customers in rates over ten years commencing in 2004. When a permanent repair is complete the costs will become part of the Company's rate base. It is not yet known when a permanent repair will be made.

Work Channel Slide

On November 5, 2004, a debris slide 25 kilometres east of Prince Rupert ruptured a section of the eight-inch high-pressure transmission pipeline. Service to 200 customers in Prince Rupert and Port Edward was interrupted for 42 hours while a replacement line was installed. The cost of temporary and permanent repairs was less than \$0.4 million.

Capital Expenditures

Total capital expenditures in 2004 were \$11.3 million, \$5.9 million higher than those incurred in 2003 and \$4.6 million above the average level of expenditures for the last five years. Of the capital expenditures in 2004, \$4.4 million was for a special project to directionally drill under the Salmon River to replace a dual underwater transmission system crossing. The capital expenditures for this project were initially estimated to be \$1.8 million. The balance of the capital expenditures was for maintenance capital as well as customer additions to the distribution system in the Northeast region.

Planned capital expenditures in 2005 are forecast to be approximately \$7.3 million. These are primarily maintenance capital expenditures for transmission mainline rehabilitation and capital expenditures for new distribution mains and services. Contractual commitments have yet to be made for major planned capital expenditures for 2005. These capital expenditures are expected to be funded from cash flow from operations.

Operating Activities

Operating, maintenance and administrative costs totalled \$18.7 million in 2004, compared to \$18.5 million in 2003. The higher expenses mainly reflect higher administrative costs associated with provision of employee benefits including health and welfare plan premiums and pension expense. These increases were partially offset by reduced maintenance costs, as a compressor overhaul was not required in 2004. Operating expenses in 2004 also included approximately \$1.0 million relating to unaccounted for gas losses, compared to nil in 2003. A consultant has been retained by the Company to identify possible causes contributing to the gas losses, which have occurred primarily in the Northeast region.

Social and Environmental Policies and Environmental Protection

In the ordinary course of its operations, the Company is required to comply with applicable federal and provincial environmental laws. The Company makes expenditures on environmental

protection in the operations of its gas pipeline and distribution systems and in the construction of new facilities. These expenditures are recovered from customers in the rates and tolls approved by the Commission. The Company does not anticipate making any material capital expenditures for environmental compliance during 2005. The Company did not incur any specific expenditures on research and development during 2004 and does not expect to do so in 2005.

Employees

At December 31, 2004, the Company had 97 employees, comprised of 77 unionized and 20 non-unionized employees. All unionized employees are members of the International Brotherhood of Electrical Workers (the "Union"). The Company's most recent collective agreement with the Union expired on November 1, 2004. The Company and the Union have signed a memorandum of agreement regarding a new three year collective agreement. The memorandum of agreement is subject to ratification by the unionized employees, which is expected to occur prior to April 15, 2005. There has been no job action initiated by the Company's unionized workers in over 20 years.

Trends and Competition

As a regulated utility, the Company does not face competition from other natural gas transmission and distribution companies. The Company does, however, compete with other energy sources in meeting the needs of energy consumers in its service areas. The main sources of competition are from electricity and wood in the residential sector, electricity in the commercial sector and wood waste in the industrial forestry sector (see "Risk Factors – Usage Risks").

The Company has experienced reductions in average gas consumption per residential and commercial customer. In 2004, the average use per customer was approximately 80% and 86%, for residential and commercial customers respectively, of the use per customer in the late 1990s. The Company believes that only a small portion of the reduction in average gas consumption has resulted from substitution of other fuels for natural gas, with only a limited amount of load having switched to electricity at this time. The main reason for the reduction in average gas consumption is conservation measures undertaken by consumers in response to higher natural gas prices and poor economic conditions experienced over this period in the Western region. Gas consumption by small industrial customers in the Western region has also declined through conservation and substitution of wood waste for natural gas.

In addition to the effect of conservation and substitution of energy sources, the Company has experienced a net loss in the number of residential customers from 2001 through 2003, with 2004 remaining flat relative to 2003. Over the same period, the number of commercial customers has been more resilient, with a small net loss in 2001 and an average annual growth rate of 0.7% since then. The poor economic conditions in the Western region are believed to be responsible for the majority of the decline in the number of residential customers. Certain small industrial customers have also closed down, contributing to the reduced economic activity in the Western region and the decline in gas consumption in the small industrial sector.

These recent trends are not necessarily indicative of future trends. Management of the Company expects there to be a limit to the conservation measures that can be undertaken by residential,

commercial and industrial customers. Further, there are a number of initiatives and prospects in the Company's Western region that could have a positive impact on the economic conditions in this service area, including:

- development of a container handling facility at the Port of Prince Rupert;
- construction of proposed oil pipelines from Alberta to tidewater at either Kitimat or Prince Rupert; and
- separate proposals for liquefied natural gas ("LNG") import and regasification facilities at Prince Rupert and Kitimat.

The proponent of the proposed LNG facility in Kitimat, Kitimat LNG Terminal ("Kitimat LNG"), has commenced the process to obtain a Project Approval Certificate from the British Columbia Environmental Assessment Office and Canadian Environmental Assessment Agency. This certificate would allow construction and operation of its project, which is proposed initially to accommodate imports of up to 610 MMcf/day of natural gas commencing in late 2008. Kitimat LNG has indicated its desire to utilize the Company's natural gas transportation services to deliver the regasified LNG into the Duke Energy Gas Transmission system at the point of the existing interconnection with the Company. The Company would be required to reverse the flow of its pipeline and expand its capacity in the event the Kitimat LNG project proceeds as planned.

In the Company's Northeast region there has been recent growth in the oil and gas sector, as well as the coal sector, which may expand the Company's customer base in that region.

RISK FACTORS

The Company faces the following strategic, financial and operational risks in carrying out its business:

Potential for Termination of Large Industrial Contracts

In 2004, approximately 75% of energy deliveries were made to the Company's three largest industrial customers, representing approximately 33% of the consolidated operating margin of the Company. The Company's contract with Methanex expires in 2009 and may be terminated prior to that date upon payment of an amount described in the contract. In 2004, deliveries to Methanex accounted for 25% of operating margin. 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. In 2004, deliveries to West Fraser accounted for 5% of operating margin. See "Business of the Company – Large Industrial Customers". 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 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 dependent upon industrial customers for its economic stability. These customers produce commodities that are subject to world commodity fluctuations. The Company's gas deliveries to these customers have been and may in the future be affected by their ability to continue to operate during sustained period 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.

Conversion to an Income Trust requires Regulatory and Other Approvals

In January 2004, the Company filed an application with the Commission for approval to reorganize the Company's business into an income trust structure. In July 2004, following a public hearing process, the Commission issued a decision denying the application. After a review of the Commission decision by management of the Company, a new application to convert to an income trust structure was filed with the Commission in December 2004. While management believes the new application addresses the concerns raised by the Commission in its denial of the first application, there can be no assurance that the Commission will provide the required approvals in order for the conversion to an income trust structure to be completed or, if so, on what terms. If Commission approval is obtained, there can be no assurance that the required shareholder or court approvals for the conversion to an income trust will be obtained, that the contemplated agreement by the Company's debenture holders allowing early redemption will be obtained, or that there will be satisfactory market conditions for the proposed initial public offering of units by the new income trust. See "Business of the Company – Application to the Commission to Convert the Company to an Income Trust Structure".

Liquidity, Cash Flow and Capital Availability Risks

In January 2005 the Company arranged new credit facilities which include a \$20 million operating line and a \$15 million risk management facility. The new 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 the Company can borrow 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. See "Management's Discussion and Analysis – Capital Resources – Short Term Debt". Further, in the event that the Company is not successful in converting to an income trust structure, it does not expect to have access to new long term debt unless its current business risks are reduced. See "Business of the Company – Application to the Commission to Convert the Company to an Income Trust Structure".

The Company is currently relying on operating cash flow to fund capital expenditures, scheduled amortization 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. In the event that operating cash flow is not adequate to meet all of these purposes, it is likely that dividends on

Common Shares would be reduced or eliminated until alternative funding was secured or other refinancing steps were taken.

Commodity Price and Supply Risks

Over the last three years, the commodity cost of natural gas has been highly volatile. The average cost of natural gas in 2004 remained at the historically high level experienced in 2003, which was more than 60% higher than in 2002. When prices are high, the prospect of fuel-switching and increased energy conservation poses 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 or counterparty failure to perform.

Usage Risks

Natural gas competes with other forms of energy available to the Company's customers and end-users, including electricity, coal and fuel oils 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 areas served by the Company. 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 was caused primarily by warmer than normal weather, 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 Risks

The Company's business and assets are subject to regulation by the Commission. Changes in the regulatory environment may be beyond the Company's control and may impact the viability of the business, 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 the GCVA, the RSAM and accounts for pipeline repair and rehabilitation. See "Business of the Company – Government Regulation".

The GCVA 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 RSAM 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, and is therefore at risk.

Facility and Insurance Risks

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

The Company maintains insurance against exposure 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 by the Company for damage to its pipeline caused by slides, washouts and other natural events, its deductibles have been increased. Depending on the number and severity of any future outages, the financial impact on the Company could be material.

These identified facility and insurance risks could affect the Company's liquidity and regulatory approval would be required for the Company to recover related costs through future rate adjustments.

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 that 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 and the Protocol came into effect on February 16, 2005. 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 utilizes derivative and other financial instruments in connection with the 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 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 Company to recover related costs through future rate adjustments.

Human Resources Risks

Most of the employees of the Company are members of a union. The Company's collective bargaining agreement with its Union expired on November 1, 2004. The Company and the Union have signed a memorandum of agreement regarding a new three year collective agreement. The memorandum of agreement is subject to a ratification vote by the unionized employees, which is expected to occur prior to April 15, 2005. See "Business of the Company – Engineering and Operations - Employees". Labour disruptions associated with the collective bargaining process can impact upon the Company's ongoing operations. In addition, the Company is dependent on maintaining its ability to attract and retain employees with the requisite skill and capabilities to operate in the complex and competitive energy industry.

Aboriginal Matters

Aboriginal groups have claimed aboriginal and treaty rights over a substantial portion of the lands on which the Company's facilities in British Columbia and the gas supply areas served by those facilities are located. The existence of these claims, which range from the assertion of rights of limited use to aboriginal title, has given rise to some uncertainty regarding access to these lands. As well, approximately three kilometres of the Company's main pipeline and approximately nine kilometres of lateral transmission pipelines cross reserves established under the *Indian Act* (Canada). The impact upon the Company of treaties or settlements with aboriginal groups is uncertain.

Share Price Volatility

A number of factors could influence the volatility in the trading of the Common Shares, including changes in the economy or in the financial markets, industry-related developments, the

impact of changes in the Company's operations and regulatory decisions affecting the Company, including decisions relating to return on equity, deemed equity component and the ability of the Company to convert to an income trust structure. Each of these factors could lead to increased volatility in the market price of the Common Shares. In addition, variations in earnings estimates by securities analysts and the market prices of the securities of companies in the same industry as the Company may also lead to fluctuations in the trading price of the Common Shares.

DIVIDENDS

The following tables set forth information concerning the payment of dividends by the Company for the last three fiscal years:

	<u>2004</u>	<u>2003</u>	<u>2002</u>
Dividends per share			
- common ⁽¹⁾	\$0.80	\$3.55	\$0.00
- preferred	\$1.69	\$1.69	\$1.69

- (1) Includes both the Class A non-voting common shares and the Class B voting common shares which were reclassified as Common Shares effective December 18, 2003.

On January 23, 2003 the Company paid a special dividend of \$2.75 per share on the Class A Non-Voting Common Shares and Class B Common shares. Dividends on the common shares were reinstated in March, 2003 at \$0.20 per share per quarter. The Company pays a semi-annual dividend of \$0.84375 per preferred share on January 1 and July 1 of each year.

DESCRIPTION OF CAPITAL STRUCTURE

The Company's authorized share capital consists of 6,020,000 Common Shares with a par value of \$2.50 each, 1,400,000 cumulative redeemable junior preferred shares with a par value of \$10 (the "Junior Preferred Shares") and 200,000 6 3/4% cumulative redeemable preferred shares with a par value of \$25 each (the "Preferred Shares"). There are 3,610,780 Common Shares, no Junior Preferred Shares and 200,000 Preferred Shares issued and outstanding at March 24, 2005.

Common Shares

Each Common Share entitles the holder to one vote per share at all meetings of shareholders of the Company, except meetings at which only holders of another specified class of shares are entitled to vote. The Common Shares are the only issued voting securities of the Company and it has no securities outstanding that can be converted into voting or equity securities.

Cumulative Redeemable Junior Preferred Shares

The Junior Preferred Shares were issued in connection with a specific transaction, and to the extent issued have been redeemed and cancelled. No further Junior Preferred Shares will be issued.

6 ¾% Cumulative Redeemable Preferred Shares

The Preferred Shares are entitled to the payment of fixed cumulative preferential cash dividends at the rate of 6 ¾% per annum on the amounts from time to time paid up thereon as when declared by the board of directors of the Company, have priority in the event of the liquidation, dissolution or winding up of the Company over the Common Shares, are non-voting and are redeemable at the option of the Company at \$26 per share plus any accrued and unpaid dividends at the date of redemption. The Company may not create shares ranking prior to the Preferred Shares but may create and issue other shares ranking on parity with those shares.

Ratings

In August 2003, subsequent to the Commission's approval of the Company's new long-term transportation contract with Methanex, Dominion Bond Rating Service ("DBRS") confirmed the Company's BB (high) rating for its secured debentures and Pfd-4 (high) rating for its 6 ¾% preferred shares and changed the trends from stable to positive. DBRS noted that the Company's access to liquidity and its near-term earnings outlook remained as obstacles to a ratings upgrade. In November 2003 DBRS raised the rating on the Company's secured debentures to BBB (low) based on: (i) the long-term contract with Methanex; (ii) positive developments in the Company's regulatory framework including the Commission approval of the rate stabilization adjustment mechanism, which mitigates variances between actual and forecast deliveries; and (iii) the Company's new \$25 million operating line of credit, which provides it with increased liquidity at a lower cost and access to a hedging line to better manage gas price volatility. In January 2005, DBRS confirmed the ratings on the Company's secured debentures and preferred shares at BBB (low) and Pfd-3 (low), respectively.

Long-term debt rated BBB is of adequate credit quality. Protection of interest and principal is considered acceptable, but the entity is fairly susceptible to adverse changes in financial and economic conditions, or there may be other adverse conditions present which reduce the strength of the entity and its rated securities.

Preferred shares rated Pfd-3 are of adequate credit quality. While protection of dividends and principal is still considered acceptable, the issuing entity is more susceptible to adverse changes in financial and economic conditions, and there may be other adverse conditions present which detract from debt protection. Pfd-3 ratings generally correspond with companies whose senior bonds are rated in the higher end of the BBB category.

DBRS noted the following key risks in arriving at the ratings on the Company's long term debt and preferred shares:

- High customer concentration, heavy exposure to industrial sector/volatile commodity prices;
- Low deemed equity in capital structure for risk profile;
- Low interest rate environment negatively impacts earnings through approved return on equity;
- Reduced competitiveness of natural gas compared to alternatives; and,
- Taxes payable method has resulted in unrecorded future income tax liability.

A security rating is not a recommendation to buy, sell or hold securities and may be subject to revision or withdrawal at any time by the rating organization.

MARKET FOR SECURITIES

The Common Shares and the 6 3/4% Cumulative Redeemable Preferred Shares of the Company are listed on the Toronto Stock Exchange. The following table sets out the price ranges and volume traded for each month of the fiscal year ended December 31, 2004 for the common shares and the 6 3/4% preferred shares:

Common shares:	High	Low	Volume
January	\$20.24	\$18.80	34,930
February	22.20	20.06	131,038
March	21.65	20.00	134,449
April	21.25	20.51	70,964
May	21.00	20.00	35,605
June	20.80	18.10	53,213
July	20.50	18.35	53,955
August	20.00	17.00	104,979
September	19.40	18.40	53,756
October	19.35	18.81	75,343
November	19.45	18.80	87,399
December	20.93	18.80	93,875

Preferred shares:	High	Low	Volume
January	\$26.05	\$24.53	4,305
February	26.50	25.50	1,815
March	27.25	25.92	2,500
April	26.50	26.50	125
May	25.36	25.36	50
June	25.80	25.80	150
July	26.50	25.80	2,410
August	25.80	25.80	248
September	26.05	25.00	1,800
October	26.40	26.00	1,650
November	26.75	26.25	2,420
December	26.25	25.25	1,395

LEGAL PROCEEDINGS

Except as described below, there are no legal proceedings material to the Company to which the Company or any of its subsidiaries is a party or of which any of their respective property is the subject matter, and there are no such proceedings known to management of the Company to be contemplated.

On April 22, 2003, Pacific Northern (N.E.) commenced an action in the Supreme Court of British Columbia against Samson Canada, Ltd. (the “Defendant”), claiming damages for breach of contract and restitution for unjust enrichment relating to gas that Pacific Northern (N.E.) transported for the Defendant to two gas well production facilities over approximately two years. Pacific Northern (N.E.) claimed that the Defendant was obligated to but did not nominate gas to Pacific Northern (N.E.) to offset the gas that Pacific Northern (N.E.) delivered to the Defendant. On June 25, 2003, the Defendant filed a statement of defence in which it claimed that it was not the original party to the gas transportation agreement and therefore was not obligated to compensate Pacific Northern (N.E.) for the gas or, in the alternative, the provisions of Pacific Northern (N.E.)’s gas tariffs restrict Pacific Northern (N.E.)’s entitlement to compensation to one year. Pacific Northern (N.E.) and the Defendant are in the process of discovery with respect to the claims and a trial date has been set for October 2005. Approximately \$1.6 million has been included by the Company in its consolidated accounts receivable at December 31, 2004, reflecting management’s estimate of the amount ultimately recoverable. However, the amount ultimately recovered could be materially different from management’s estimate.

DIRECTORS AND OFFICERS

The following table sets out the names of the directors, as well as other pertinent information, including: principal occupation or employment, province and country of residence, all major positions and offices presently held in the Company, the year first elected a director of the Company and the approximate number of shares of the Company beneficially owned, directly or indirectly, or over which control or direction is exercised by such person. The directors serve for a term from the date of election until the next annual meeting or until their respective successors have been elected or appointed. The directors and officers as a group own, directly or indirectly, or exercise control or direction over approximately 3.4% of the issued and outstanding common shares of the Company.

Directors

<i>Name, Principal Occupation and Other Information</i>	<i>Beneficial Ownership or Control of Common Shares</i>
<u>Robert F. Chase</u> Chairman of the Board; President and Chief Executive Officer of Lexacal Investment Corp. (an oil and gas services company); resident in British Columbia, Canada; a director of the Company since April 26, 1995 ^{1,2,3}	Nil
<u>Roy G. Dyce</u> President and Chief Executive Officer of Pacific Northern Gas Ltd.; a director of the Company since April 29, 1982	58,546

<p><u>J. Trevor Johnstone</u> Managing Director of Tricor Pacific Capital, Inc. (a private equity firm); resident in British Columbia, Canada; a director of the Company since December 18, 2003 ^{1,4}</p>	<p>Nil</p>
<p><u>Hugh C. Morris</u> Chairman of Eldorado Gold Company (a gold producer and exploration company); resident in British Columbia, Canada; a director of the Company since May 1, 1986 ^{1,5}</p>	<p>400</p>
<p><u>David J. Rowntree</u> Managing Director of Tricor Pacific Capital, Inc. (a private equity firm); resident in British Columbia, Canada; a director of the Company since December 18, 2003 ^{3,5}</p>	<p>Nil</p>
<p><u>Roderick R. Senft</u> Managing Director of Tricor Pacific Capital, Inc. (a private equity firm); resident in British Columbia, Canada; a director of the Company since December 18, 2003 ²</p>	<p>Nil</p>
<p><u>David G. Unruh</u> Vice Chairman & Director of Westcoast Energy Inc. (a natural gas gathering, processing and transmission company); resident in British Columbia, Canada; a director of the Company since March 21, 2002 ^{4,5}</p>	<p>Nil</p>
<p><u>Arthur H. Willms</u> Director of Westcoast Energy Inc. (a natural gas gathering, processing and transmission company); resident in British Columbia, Canada; a director of the Company since April 28, 1983 ^{2,3,4}</p>	<p>Nil</p>

- (1) *Member of the Audit Committee*
- (2) *Member of the Executive Committee*
- (3) *Member of the Human Resources and Compensation Committee*
- (4) *Member of the Corporate Governance Committee*
- (5) *Member of the Environment, Health and Safety Committee*

Officers

<i>Name, position and other information</i>	<i>Beneficial Ownership or Control of Common Shares</i>
<p><u>Robert F. Chase</u> Chairman of the Board British Columbia, Canada</p>	<p>Nil</p>
<p><u>Roy G. Dyce</u> President and Chief Executive Officer British Columbia, Canada</p>	<p>58,546</p>

<i>Name, position and other information</i>	<i>Beneficial Ownership or Control of Common Shares</i>
<u>Greg B. Weeres</u> Vice President, Operations and Engineering, British Columbia, Canada	15,238
<u>Elizabeth A. Fletcher</u> Chief Financial Officer British Columbia, Canada	23,122
<u>Kevin R. Teitge</u> Director, Corporate Development and Treasurer British Columbia, Canada	15,385
<u>Craig P. Donohue</u> Director, Regulatory Affairs & Gas Supply and Assistant Secretary British Columbia, Canada	11,538
<u>Kelly E. Stark-Anderson</u> Secretary British Columbia, Canada	Nil

During the last five years, all of the directors and officers have been employed in various capacities by the Company or by the companies indicated opposite their names except: Ms. E.A. Fletcher was Manager, Finance & Administration with Star Shipping (Canada) Ltd. prior to January 1999 until March 2000; Mr. K.R. Teitge was an independent consultant from June 2003 through January 2004 and was Director, Corporate and Project Finance, Westcoast Energy Inc. prior to January 1999 until June 2003; Ms. K.E. Stark-Anderson is Assistant General Counsel and Corporate Secretary of Westcoast Energy Inc.

Audit Committee

The Terms of Reference of the Audit Committee of the Board of Directors of the Company is attached as Schedule A to this Annual Information Form.

Messrs. Morris, Chase and Johnstone served as the members of the Audit Committee during the fiscal year ended December 31, 2004. Each member of the Audit Committee is independent and all members are financially literate as defined under Multilateral Instrument 52-110 "Audit Committees". Mr. Morris, the Chair of the Audit Committee, has a diploma from the Banff School of Advanced Management. He is currently a member of the Audit Committee of two publicly listed Canadian corporations, including Eldorado Gold Corp. and Diamond Resources Inc. Mr. Chase is

a chartered accountant and has worked in areas related to financial management and reporting for over thirty years, including acting as a consultant for KPMG LLP and was employed as the Chief Financial Officer for various companies including the Westar Group. Mr. Johnstone is a chartered accountant and a certified public accountant (inactive) with eighteen years experience in public practice. He is the chairman of the Audit and Finance Committee of the Vancouver Coastal Health Authority, the largest health authority in Canada. He is also a member of the Audit Committee of four public entities.

The Audit Committee is responsible for approving non-audit services to be provided by the auditors and does so in accordance with the requirements of its Terms of Reference.

INTERESTS OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

The Company had no transactions with related parties during 2004.

The Company's related party transactions in 2003 and 2002, described in items (a) to (e) below, were conducted with entities that are no longer affiliates of the Company as a result of the sale of 100 percent of the interest in the capital of the Company held by Westcoast Energy Inc. ("Westcoast") to Tricor Acquisition (STP) Inc. ("Tricor") which closed on December 18, 2003. The Company has determined that Tricor is not a related party.

- (a) During the fiscal year ended on December 31, 2003, the Company paid \$876,000 [2002 - \$834,000] to Westcoast for the transportation of natural gas through Westcoast's natural gas pipeline system. The National Energy Board of Canada regulates the rates and tolls charged for, and the terms and conditions under which natural gas is processed and transported by Westcoast through its pipeline system. The services provided to the Company during 2003 and 2002 were provided on the same terms as those provided to all other shippers of gas on Westcoast's pipeline system.
- (b) During the fiscal year ended on December 31, 2003, the Company paid \$463,000 [2002 - \$588,000] to Westcoast for various materials and services provided by Westcoast. The Company believes that the terms of those transactions are no less favourable than those that could have been arranged with unrelated third parties.
- (c) During the fiscal year ended on December 31, 2003, the Company paid \$2,253,000 [2002 - \$528,000] to Westcoast Energy Risk Inc., a subsidiary of Westcoast, in premiums for various insurance programs and coverage for a period spanning November 2002 through the first half of 2004. A portion of these premiums were refunded in 2004 following the sale of Westcoast's interest in the Company on December 18, 2003. The Company believes that the terms of those transactions are no less favourable than those that could have been arranged with unrelated third parties.
- (d) During the fiscal year ended on December 31, 2003, the Company paid \$197,000 [2002 - \$5,323,000] to Engage Energy Canada, L.P. ("Engage Energy"), an affiliate of Westcoast, for gas supply management services and seasonal gas supply requirements. In addition, for

the period from January 1, 2003 through May 31, 2003 the Company sold gas on a daily basis that it was required to purchase under its supply contracts but that was excess to its system needs to Engage Energy. During the fiscal year ended December 31, 2003, Engage Energy paid the Company \$23,121,000 [2002 - \$15,110,000] for such excess gas supplies. The Company believes that the terms of those transactions are no less favourable than those that could have been arranged with unrelated third parties.

- (e) During the fiscal year ended on December 31, 2003, the Company paid \$19,385,000 [2002 - \$2,034,000] to Duke Energy Marketing LP, an affiliate of Westcoast, for seasonal gas supply requirements during the months of January, February and March 2003. The Company believes that the terms of those transactions are no less favourable than those that could have been arranged with unrelated third parties.

TRANSFER AGENT

The Company's transfer agent is Computershare Trust Company of Canada with registers maintained in Vancouver, Calgary, Regina, Winnipeg, Toronto and Montreal.

EXPERTS

The Company's auditors are Deloitte & Touche LLP. The report of the auditors on the financial statements for the fiscal year ended December 31, 2004 has been filed on www.sedar.com with the securities regulators. Deloitte & Touche LLP does not hold any registered or beneficial ownership, either directly or indirectly, in any securities of the Company.

	Audit Fees	Audited-Related Fees⁽¹⁾	Tax Fees⁽²⁾	All Other Fees
2003	\$97,033	\$13,529	\$85,600	\$—
2004	\$94,000	\$22,946	\$10,000	\$—

⁽¹⁾ Audited-related fees pertain to review of annual and interim reports, audit of pension plans, and assistance with implementing CEO/CFO certification processes.

⁽²⁾ Tax services include assistance with the preparation of corporate income tax returns, and review of tax planning strategies including assessment of income trust alternatives.

ADDITIONAL INFORMATION

Additional Information concerning the Company can be found at www.sedar.com. Additional information, including information as to directors' and officers' remuneration and indebtedness, principal holders of the Company's securities, options to purchase securities and securities authorized for issuance under equity compensation plans, is contained in the Management Proxy Circular dated March 18, 2005 for the Company's 2005 Annual Meeting of Shareholders. Additional financial information is provided in the Company's consolidated financial statements for the year ended December 31, 2004. Management's Discussion and Analysis, which appears on pages 12 to 31, inclusive, of the Company's 2004 Annual Report, is incorporated by reference into and forms an integral part of this annual information form. Copies of these documents may be obtained upon request from the Secretary, Pacific Northern Gas Ltd., 950 -1185 West Georgia Street, Vancouver, British Columbia, V6E 4E6.

SCHEDULE "A"

PACIFIC NORTHERN GAS LTD. (the "Corporation")

AUDIT COMMITTEE

TERMS OF REFERENCE

PURPOSE

The overall purpose of the Audit Committee is to ensure that: (i) the Corporation's management has designed and implemented an effective system of internal financial controls, (ii) to review and report on the integrity of the consolidated financial statements of the Corporation, (iii) to review the Corporation's compliance with regulatory and statutory requirements as they relate to financial statements, taxation matters and disclosure of material facts, and (iv) to monitor and oversee the independent auditors' qualifications, independence and activities.

COMPOSITION, PROCEDURES AND ORGANIZATION

1. The Board of Directors of the Corporation (the "Board"), at its organizational meeting held in conjunction with each annual general meeting of the shareholders, shall appoint the members of the Committee for the ensuing year. The Board may at any time remove or replace any member of the Committee and may fill any vacancy in the Committee.
2. The Committee shall consist of at least three members of the Board all of whom shall be independent as determined in accordance with applicable securities laws, rules, regulations and guidelines ("Securities Laws"). All Committee members shall be financially literate. For this purpose, financial literacy shall mean the ability of a member to read and understand a set of financial statements that present a breadth and level of accounting issues that are generally comparable to the breadth and complexity of the issues that can reasonably be expected to be raised by the Corporation's financial statements. At least one member should have accounting or related financial expertise.
3. Unless the Board shall have appointed a Chair of the Committee, the members of the Committee shall elect a Chair from amongst their number.
4. The Chief Financial Officer of the Corporation shall be the secretary of the Committee, unless otherwise determined by the Committee.
5. The quorum for meetings shall be a majority of the members of the Committee, present in person or by telephone or other telecommunication device that permits all persons participating in the meeting to speak and to hear each other.

6. Meetings of the Committee shall be conducted as follows:
 - a) the Committee shall meet at least four times annually at such times and at such locations as may be requested by the Chair of the Committee. The independent auditors, the internal auditors and any member of the Committee may request a meeting of the Committee;
 - b) notice of meeting may be given orally or by letter, telex, telegram, facsimile transmission or telephone not less than 24 hours before the time fixed for the meeting. Members may waive notice of any meeting. The notice need not state the purpose or purposes for which the meeting is being held;
 - c) the independent auditors and the internal auditors shall receive notice of and have the right to attend all meetings of the Committee; and
 - d) the Chief Executive Officer shall be invited to attend all meetings, except executive sessions and private sessions with the independent auditors. Other management representatives shall be invited to attend as necessary.
7. The internal auditors and the independent auditors shall have a direct line of communication to the Committee through its Chair and may bypass management if deemed necessary. The independent auditors shall report to the Committee and are ultimately accountable to the Board and the Committee, as representatives of the shareholders.
8. The Committee, through its Chair, may contact directly the independent auditors, the internal auditors and any employee of the Corporation as it deems necessary. Any employee may bring before the Committee any matter involving questionable, illegal or improper financial practices or transactions.
9. The Committee shall have access to officers of the Corporation, the Corporation's legal counsel and such information respecting the Corporation as it considers necessary or advisable in order to perform its duties and responsibilities.
10. The Committee shall have the authority to engage independent counsel and other advisors as it determines necessary to carry out its duties and to set and pay the compensations for any advisors so engaged.
11. The Committee shall have the power to delegate its authority and duties to subcommittees or individual members of the Committee as it deems appropriate.

ROLES AND RESPONSIBILITIES

1. Overall Duties and Responsibilities

The overall duties and responsibilities of the Committee shall be as follows:

- a) to assist the Board in the discharge of its responsibilities relating to the quality, acceptability and integrity of the Corporation's accounting principles, reporting practices and internal controls;
- b) to assist the Board in the discharge of its responsibilities relating to compliance with disclosure requirements under applicable Securities Laws, including approval of the Corporation's annual and quarterly consolidated financial statements together with the Management's Discussion and Analysis;
- c) to establish and maintain a direct line of communication with the Corporation's independent auditors and internal auditors and assess their performance;
- d) to ensure that the management of the Corporation has designed, implemented and is maintaining an effective system of internal controls; and
- e) to report regularly to the Board on the fulfillment of its duties and responsibilities.

2. **Independent Auditors**

The duties and responsibilities of the Committee as they relate to the independent auditors shall be as follows:

- a) to recommend to the Board a firm of independent auditors to be engaged by the Corporation;
- b) to review, at least annually, with the independent auditors their independence from management, including a review of all other significant relationships the auditors may have with the Corporation and to satisfy itself of the auditors' independence, the experience and the qualifications of the senior members of the independent auditor team and the quality control procedures of the independent auditor.
- c) to review and approve the fee, scope, staffing and timing of the audit and other related services rendered by the independent auditors and ensure the rotation of the lead audit partner as required by applicable Securities Laws;
- d) to be responsible for overseeing the work of the independent auditors and reviewing the audit plan prior to the commencement of the audit;
- e) to review the engagement reports of the independent auditors on unaudited financial statements of the Corporation and to review with the independent auditors, upon completion of their audit:

- i) contents of their report;
- ii) scope and quality of the audit work performed;
- iii) adequacy of the Corporation's financial and auditing personnel;
- iv) co-operation received from the Corporation's personnel during the audit;
- v) internal resources used;
- vi) significant transactions outside of the normal business of the Corporation;
- vii) significant proposed adjustments and recommendations for improving internal accounting controls, accounting principles and management systems;
- viii) the quality, acceptability and integrity of the Corporation's accounting policies and principles;
- ix) the non-audit services provided by the independent auditors;
- x) the effect of regulatory and accounting initiatives as well as off-balance sheet structures on the Corporation's financial statements;

and report to the Board in respect of the foregoing;

- f) to implement structures and procedures to ensure that the Committee meets the independent auditors on a regular basis in the absence of management in order to review any difficulties encountered by the independent auditors in carrying out the audit and to resolve disagreements between the independent auditors and management; and
- g) to pre-approve the retention of the independent auditor for any non-audit service and the fee for such service.

The Committee may satisfy the pre-approval requirement in subsection 2(g) if:

- i) the aggregate amount of all the non-audit services that were not pre-approved constitutes no more than five per cent of the total amount of revenues paid by the Corporation to its independent auditors during the fiscal year in which the services are provided;
- ii) the services were not recognized by the Corporation at the time of the engagement to be non-audit services; and
- iii) the services are promptly brought to the attention of the Committee and are approved, prior to the completion of the audit, by the

Committee or by one or more members of the Committee to whom authority to grant such approvals has been delegated by the Committee.

The Committee may delegate to one or more independent members the authority to pre-approve non-audit services in satisfaction of the requirement in subsection 2(f) provided that the pre-approval of non-audit services by any member to whom authority has been delegated must be presented to the full Committee at its first scheduled meeting following such pre-approval.

3. **Internal auditors**

The duties and responsibilities of the Committee as they relate to the Corporation's internal auditors are to:

- a) periodically review the internal audit function with respect to the organization, staffing and effectiveness of the internal audit department;
- b) review and approve the internal audit plan; and
- c) review significant internal audit findings and recommendations, and management's response thereto.

4. **Internal Control Procedures**

The duties and responsibilities of the Committee as they relate to the internal control procedures of the Corporation are to:

- a) review the adequacy, appropriateness and effectiveness of the Corporation's policies and business practices which impact on the integrity, financial and otherwise, of the Corporation, including those relating to internal auditing, insurance, accounting, information services and systems and financial controls, management reporting, code of conduct and risk management;
- b) review compliance under the Corporation's business conduct policy;
- c) review any issues between management and the independent auditors that could affect the financial reporting or internal controls of the Corporation;
- d) periodically review the Corporation's accounting and auditing policies, practises and procedures and the extent to which recommendations made by the internal audit staff or by the independent auditors have been implemented; and
- e) Ratify membership of the Disclosure Committee, as required, as appointed by the Senior Officers of the Corporation.

5. **Public Filings, Policies and Procedures**

The Committee is charged with the responsibility to:

- a) review and approve for recommendation to the Board:
 - i) the annual report to shareholders, including the annual audited financial statements, with the report of the independent auditors, the Management's Discussion and Analysis and the impact of unusual items and changes in accounting principles and estimates;
 - ii) the interim report to shareholders, including the unaudited financial statements, the Management's Discussion and Analysis and the impact of unusual items and changes in accounting principles and estimates;
 - iii) earnings press releases;
 - iv) the annual information form;
 - v) prospectuses; and
 - vi) other public reports and public filings requiring approval by the Board;

and report to the Board with respect thereto;

- b) review regulatory filings and decisions as they relate to the Corporation's consolidated financial statements;
- c) ensure adequate procedures are in place for the review of the Corporation's disclosure of financial information extracted or derived from the Corporation's financial statements, other than the disclosure described in subsection 5(a) above, and periodically assess those procedures;
- d) review with management, the independent auditors and if necessary with legal counsel, any litigation, claim or other contingency, including tax assessments, that could have a material affect upon the financial position or operating results of the Corporation and the manner in which such matters have been disclosed in the consolidated financial statements;
- e) review with management and with the independent auditors any proposed changes in major accounting policies, the presentation and impact of significant risks and uncertainties, and key estimates and judgements of management that may be material to financial reporting;

- f) review with management and with the independent auditors (i) all critical accounting policies and practises to be used by the Corporation in preparing its financial statements, (ii) all material alternative treatments of financial information within GAAP that have been discussed with management, ramifications of the use of these alternative disclosures and treatments, and the treatment preferred by the independent auditor, and (iii) other material communications between the independent auditor and management, such as any management letter or schedule of unadjusted differences;
- g) review general accounting trends and issues of auditing policy, standards and practices which affect or may affect the Corporation;
- h) review the appointments of the Chief Financial Officer and any key financial executives involved in the financial reporting process;
- i) establish procedures for:
 - i) the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal controls, or auditing matters; and
 - ii) the confidential, anonymous submission by employees of the Corporation of concerns regarding questionable accounting or auditing matters.
- j) review and approve the issuer's hiring policies regarding employees and former employees of the present and former independent auditors of the Corporation;
- k) review and approve related party transactions.

6. **Pension and Savings Plans**

The Committee is charged with the responsibility to:

- (2) Approve the Statements of Policies and Procedures for the Employees' Retirement Plan and other Plans as required and any amendments required thereto;
- (3) Appoint the auditors, review the scope of the audit plan and review and approve the audited financial statements for the Employees' Retirement Plan, the Supplemental Executive Retirement, the Employee Savings Program, the Group RRSP and the non-pension post-retirement benefits (collectively, the "Plans");
- (4) Receive a report from the Pension and Savings Plan Committee (the "PSPC") after each of its meetings and report to the Board thereon;

- (5) Receive semi-annually a report from the PSPC including (i) a summary of the activities of the PSC during the relevant period; (ii) a summary and evaluation of the investment performance of the funds associated with the Plans (the “Funds”) for the applicable period; (iii) where there has been any change in any Investment Manager during the relevant period, a summary of the factors leading up to the decision for such change, a report on the process that was undertaken to implement such change and a summary of the factors that influenced the decision of the Committee in selecting any new Investment Manager; and (iv) where there has been any change in any third party providers of pension-related services during the relevant period (other than changes in Investment Managers), including actuaries, auditors, pension consultants and outsourcers of pension administration, a report on such change; and report to the Board thereon.
- (6) Receive an annual report from the PSPC including (i) the audited financial statements of the Plans and the Funds; (ii) a summary of the changes in the liabilities of the Plans with sensitivity analysis to interest rates, demographic factors and any other factors that may be indicated from time to time; (iii) The Statement of Investment Policy and Procedures for each of the Funds, containing such amendments as have been recommended by the PSPC.

7. **Calendar**

The Committee will develop a calendar of activities, attached as Appendix A, to be undertaken by the Committee for each ensuing year and to submit the calendar in the appropriate format to the Board of Directors on an annual basis.

Revised: February 11, 2005

APPENDIX A

AUDIT COMMITTEE

CALENDAR OF ACTIVITIES

	<u>Feb</u>	<u>April</u>	<u>July</u>	<u>Oct</u>
Review and Approve Financial Statements and Reports:				
• Financial Statements.	✓	✓	✓	✓
• Interim Report, including MD&A.		✓	✓	✓
• Annual Report, including MD&A.	✓			
• Annual Information Form.	✓			
• Review Major Accounting Policies and Significant Estimates.	✓	✓	✓	✓
• Consider Changes in Accounting Principles and whether Industry/Standards are being followed.	✓	✓	✓	✓
• Consider Unresolved Differences of Opinion between Management and the Auditor.	✓	✓	✓	✓
External Auditors:				
• Review Scope of Audit and Audit Plan.			✓	
• Discuss Audit Report and Findings.	✓			
• Review Recommendations and Response to Audit Report.	✓			
• Review Auditor Independence.	✓		✓	
• Review Cooperation and Services Provided by Management.	✓			
• Recommend Appointment of Auditors.	✓			
• Review Audit Fees.	✓			

	<u>Feb</u>	<u>April</u>	<u>July</u>	<u>Oct</u>
• Meeting with Auditors - without Management.	✓	✓	✓	✓
• Review Non-Audit Services.	✓	✓	✓	✓

Risk Management and Control:

• Review Effectiveness of Internal Audit Function and Review the Internal Audit Plan.		✓		
• Review Internal Audit Findings.				✓
• Assess Compliance with Code of Corporate Conduct.				✓
• Review of Deferred Charges.	✓	✓	✓	✓
• Receive Report on Derivatives.	✓	✓	✓	✓
• Adequacy of Allowance for Doubtful Accounts.	✓	✓	✓	✓
• Assessment of Adequacy of Insurance Coverage.	✓			
• Review Philosophy on Control and Information Systems.				✓
• Ensure Compliance with Legal and Regulatory Responsibilities.	✓			
• Annual Review of Delegation of Authority to Management and of Management's Compliance.	✓			

Pension and Savings Plans Committee:

• Receive Minutes of Meetings of PSPC	✓	✓	✓	✓
• Receive Semi-Annual Report from PSPC	✓		✓	
• Receive Annual Report from PSPC		✓		

	<u>Feb</u>	<u>April</u>	<u>July</u>	<u>Oct</u>
• Appoint Auditors and Review Scope of Audit for the Funds.		✓		
• Review Audited Financial Statements for the Funds.			✓	
Other:				
• Adequacy of Complement in Accounting, Customer Billing and Finance.				✓
• Assess Circumstances Adverse to the Company.	✓	✓	✓	✓
• Review any Material Litigation.	✓	✓	✓	✓
• Monitor Procedures for Reviewing Officers' Expenses.				✓
• Review Appointment of Financial Personnel.		✓		
• Review Terms of Reference and Calendar of Activities for Ensuing Year.				✓

Revised: February 11, 2005