



PACIFIC NORTHERN GAS LTD.

**ANNUAL
INFORMATION FORM**

For the 12 month period ended December 31, 2008

March 4, 2009

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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, one thousand cubic metres is equivalent to 35.30 thousand cubic feet.

Non-GAAP Measures

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 performance. Management believes operating margin is a meaningful measure of performance because its financial results are best measured by excluding the cost of gas which is flowed through to customer rates without a mark-up

SPECIAL NOTE REGARDING FORWARD LOOKING STATEMENTS

This annual information form includes forward-looking statements. Forward-looking statements relate to, among other things, anticipated financial performance, business prospects, strategies, regulatory developments, new services, market forces, commitments and technological developments. Many of these statements can be identified by words such as “believe”, “expects”, “expected”, “will”, “intends”, “projects”, “anticipates”, “estimates”, “continues” or similar words. The Company believes the expectations reflected in such statements are reasonable but no assurance is given that such expectations will be correct. All forward-looking statements are based on management’s beliefs and assumptions based on information available at the time the assumption was made and on its experience and perception of historical trends, current conditions and expected further developments as well as other factors deemed appropriate in the circumstances. In addition to other assumptions made in this annual information form, assumptions have been made in respect of:

- gas commodity prices;
- forecasted gas deliveries;
- regulatory conditions, including decisions by the British Columbia Utilities Commission (the “Commission”);
- the Company’s ability to access capital;
- capital expenditure estimates, plans, schedules and activities and the development, construction, operations and cost of facilities and infrastructure;
- income tax considerations;
- operating risks and related insurance coverage and inspection and integrity systems; and
- competitive conditions.

By its nature, such forward-looking information is subject to various risks and uncertainties that are known and unknown, including those material risks discussed in this annual information form under “Risk Factors” which could cause the Company’s actual results and experience to differ materially from the anticipated results or other expectations expressed. Such risks and uncertainties include but are not limited to: general economic conditions and markets and, in particular, the potential impact of the current economic downturn; gas supply and availability; gas commodity price volatility; competition; decisions by regulators; seasonal weather patterns; federal and provincial climate change initiatives; financing of investments as well as the value of such investments; the cost and availability of capital; the impact on the Company’s liquidity if it were to go offside of the covenants in its debt facilities; successful execution of strategic initiatives; and the ability of the Company to attract and retain quality employees. Readers are cautioned not to place undue reliance on this forward-looking information, which is given as of the date it is expressed in this annual information form or otherwise, and the Company undertakes no obligation to update publicly or revise any forward-looking information, whether as a result of new information, future events or otherwise, except as required by applicable securities laws.

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 system”). Pacific Northern (N.E.) owns and operates a distribution utility in the northeast part of British Columbia (“Northeast system”). The Northeast system is comprised of two divisions, the Fort St. John/Dawson Creek division and the Tumbler Ridge division. The utilities are separate stand-alone systems and both are regulated by the Commission.

In 2005 the Company commenced development of a project to loop its mainline transmission system from Kitimat to Summit Lake (the “KSL Project”). The KSL Project would provide gas transportation services for up to 1.0 billion cubic feet per day to a proposed Kitimat LNG Inc. liquefied natural gas (“LNG”) export terminal to be located approximately 15 kilometers southwest of Kitimat. The LNG export terminal would be constructed by Kitimat LNG Inc., a subsidiary of Galveston LNG Inc., a private company based in Calgary, Alberta (“Kitimat LNG”), at the same location as their originally proposed LNG import and regasification terminal. Strong natural gas demand in Asia and increases in gas supply throughout North America have led to higher natural gas prices in Asia than in North America. On this basis, Kitimat LNG has determined that the exporting of LNG is more viable than the earlier proposal to import LNG. The gas for the LNG export terminal would be transported to the Company’s existing interconnection with the system owned by Westcoast Energy Inc., a Spectra Energy company (“Spectra Energy”). The KSL Project would entail the construction of approximately 470 kilometers of a 36 inch diameter pipeline and associated compression facilities, at a cost of \$1.2 billion based on estimates made in 2006. The route for the KSL Project has been determined through technical field studies and consultation with First Nations, the public and regulatory authorities. The Company’s existing right-of-way would be used where appropriate. In 2006, Kitimat LNG received a Project Approval Certificate from the British Columbia Environmental Assessment Office (“BCEAO”) as well as approval from the Canadian Environmental Assessment Agency (“CEAA”) for the construction and operation of the originally planned import and regasification terminal. Canadian Federal Government approval for the liquefaction and export terminal (the “Terminal”) was received on December 10, 2008 and B.C. Provincial Government approval was received on January 9, 2009.

On July 17, 2006, the Company formed Pacific Trail Pipelines Limited Partnership (“PTP”) as a 50/50 partnership between the Company and Galveston LNG Inc. for the purpose of developing the KSL Project. At that time, PTP and Kitimat LNG also executed a Precedent Agreement to coordinate the process of obtaining authorizations for the KSL Project with the development of the original terminal. The Precedent Agreement also set out the key economic arrangements between PTP and Kitimat LNG, the targeted timeline and key milestones for construction of the KSL Project and the original terminal. The companies are making amendments to the Precedent Agreement to address, among other things, the impact on the original time lines resulting from changing to an LNG export project.

On June 27, 2008, PTP received its Environmental Assessment Certificate from the B.C. Environmental Assessment Office (“BCEAO”) for the KSL Project. Approvals from the Canadian Environmental Assessment Agency (“CEAA”) are expected to be granted before the end of the first quarter in 2009.

Kitimat LNG and Mitsubishi Corporation (“MC”) announced in January 2009 the signing of a Heads of Agreement that set forth the terms pursuant to which MC will contract significant terminal capacity and acquire a minority equity stake in Kitimat LNG’s proposed LNG export terminal. With MC’s expected involvement as an anchor tenant in the Kitimat LNG export terminal, PNG anticipates MC will also become a significant customer of the KSL Project, requiring associated natural gas transportation service of approximately 200 million cubic feet per day to the LNG export terminal. PTP and Kitimat LNG have received other non-binding

expressions of interest from parties interested in pipeline and terminal capacity and discussions with these parties are continuing.

Subject to a number of conditions, construction of the KSL Project by PTP is planned to commence in 2011 for completion in mid 2013 when the LNG export terminal is planned to begin operation. Conditions to construction include the securing of contracts for use of PTP's transportation capacity, financing for construction of the KSL Project, and additional regulatory approvals for the KSL Project, including approvals under the Canadian Environmental Assessment Act, a Certificate of Public Convenience and Necessity from the Commission and other permits from the B.C. Oil and Gas Commission. The Company can give no assurances that these conditions will be satisfied or that construction of the LNG export terminal by Kitimat LNG or the KSL Project by PTP will proceed. Upon completion of the KSL Project, and subject to regulatory and shareholder approvals, the Company's existing mainline transmission system will be transferred to PTP and integrated with the KSL Project facilities. The Company would continue to own and operate its existing gas distribution systems, including its Customer Care Centre in Terrace.

The cumulative cost associated with the KSL Project incurred by the Company to the end of 2007 was \$4.9 million (\$3.0 million after income taxes). A further \$0.8 million (\$0.6 million after income taxes) was incurred in 2008. The Company is currently expensing all KSL Project development expenditures until suitable commercial arrangements for firm gas transportation services by PTP are in place. Management expects that the Company's share of development expenditures on the KSL Project in 2009 will be approximately \$0.2 million (\$0.14 million after income taxes). Following environmental certification, expenditures on the KSL Project will be minimized until suitable commercial arrangements for firm gas transportation services by PTP are in place at which point development costs of the project would commence being capitalized.

PNG filed an application with the Commission on September 25, 2008 for approval of a term sheet setting out the terms under which PNG would provide LNG Partners, LLC ("LNG Partners") with an option to contract for a minimum 75 MMcf per day of firm gas transportation service using existing capacity on PNG's Western system. LNG Partners proposed to utilize the transportation service for delivery of natural gas to a floating natural gas liquefaction vessel to be owned and operated by an LNG Partners affiliate on the Douglas Channel near Kitimat, B.C. The LNG would then be transferred to other LNG carriers for export.

The arrangement was approved by the Commission on November 27, 2008 triggering an obligation by LNG Partners to pay a \$1.5 million non-refundable fee to PNG for an exclusive 6 month option to contract firm gas transportation capacity for a 3 to 5 year primary term, with a right to renew for an additional 3 to 5 year term. Alternatively, LNG Partners would have the right to extend the initial option period for another six months on payment of an additional non-refundable option fee of \$1.5 million. LNG Partners has yet to pay the initial option fee which was due on December 15, 2008. PNG has applied for Commission approval to apply approximately two-thirds of the initial option fee, if received, to reduce customer rates in 2009 with the remaining one-third to compensate PNG for the reduced return it has earned since the Methanex closure at the end of 2005. This request was deferred for consideration under PNG's 2009 revenue requirements application. Pending receipt of the initial option fee, the Company is

in discussions with other parties that may wish to contract with PNG for capacity on the Western system.

If LNG Partners makes the option payment and exercises its option, service would be expected to commence some time in 2011 and the PNG pipeline system would be at full capacity utilization, generating almost \$15 million per year of incremental revenue for the benefit of PNG and its customers, compared to approximately \$12 million previously received annually from Methanex.

The Company can give no assurances that LNG Partners will make the option payment or that, if the option fee is paid, it will exercise its option to take capacity on the Western system.

On March 4, 2009, the Company announced that it had obtained the approval of the Toronto Stock Exchange (the "TSX") to commence a normal course issuer bid on March 9, 2009. Under the bid, the Company will from time to time acquire its common shares at the then current market price through the facilities of the TSX. All shares purchased under the bid will be cancelled. A repurchase of the Company's common shares at market prices which are well below the book value of the shares, is expected to improve shareholder value.

The bid, subject to renewal, will terminate on the earlier of March 8, 2010 and the date on which the Company has acquired 300,000 shares, the approximate maximum number of shares permitted under the bid. The actual number of shares purchased, the time of the purchases and the prices at which the shares will be bought will depend on future market conditions.

On August 30, 2005, one of the Company's large industrial customers, Methanex Corporation ("Methanex") gave notice of termination of its transportation agreement with the Company. Under the terms of the agreement, Methanex made a termination payment to the Company of approximately \$23.3 million on February 28, 2006, the effective date of the termination. Under the terms of a negotiated settlement with registered intervenors and approved by the Commission on November 17, 2005, the termination payment was recorded as an interest bearing credit deferral, to be amortized into income over the period March 1, 2006 to October 31, 2009, the original date of expiry of the transportation agreement. The Company sought and obtained Commission approval in its 2006 revenue requirements application to recover an estimated \$4.8 million in net margin reduction in 2006, due to the Methanex agreement termination, from its remaining customers. Similarly, the Company is seeking Commission approval in its 2009 revenue requirements application to recover \$1.1 million in response to the impact of the full amortization in rates of the Methanex termination payment as of October 31, 2009.

Trends and Competition

Competitiveness of Rates

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 continues to focus on the competitiveness of its rates relative to alternative heating sources in the Western system service area, primarily electricity. The Western system residential rates have been slightly higher than comparable electricity rates over the last few years while commercial gas rates have been lower than electricity rates. Both residential and commercial gas rates remain lower than electricity rates in the Northeast system service area.

The Province of British Columbia's Energy Plan, released in early 2007, calls for the Province to become self-sufficient in electricity by 2016 with all new generation capacity being carbon neutral and to use demand side management to curtail growing electricity consumption. These policy objectives are expected to result in higher electricity rates with a corresponding impact on the competitiveness of gas relative to electricity. More specifically, electricity rate increases effective April 1, 2008 were approximately 5 percent and are expected to be an additional 15 percent on a cumulative basis over the following two years. Effective October 1, 2008, the British Columbia Hydro and Power Authority ("BC Hydro") implemented an inclining rate structure for residential customers to encourage electricity conservation. The two-tiered pricing structure provides that a higher electricity price applies to consumption in excess of a base amount. The higher rate is to be increased further as of April 1, 2009. The Company's gas rates are currently competitive with the higher rate. The Company believes that the new pricing structure will help discourage its residential customers from using electricity in substitution for space and water heating with natural gas.

Amendments made to the Utilities Commission Act in 2008 focus on the energy conservation and demand side management goals and objectives set forth in the new BC Energy Plan. PNG is participating with government stakeholder groups to keep apprised of potential cost effective demand side management initiatives that make sense for its customers.

The Province of British Columbia implemented a carbon tax on fossil fuel consumption in 2008. The carbon tax on natural gas was set at just under \$0.50 per GJ effective July 1, 2008 and will rise at approximately \$0.25 per GJ each July 1 to just under \$1.50 per GJ effective July 1, 2012.

Notwithstanding the impacts of carbon tax on natural gas and the cessation of the Methanex termination payment credit amortization in 2010, the Company expects its retail gas rates will remain competitive with electricity rates over the long term.

Customer Usage and Current Economic Conditions

The Company, like other gas utilities in Canada, has experienced reductions in average gas consumption per residential and small commercial customer over the last several years. However, deliveries to residential and commercial customers in 2008 were higher by 100 terajoules or 1.6 percent, compared to deliveries in 2007 due primarily to colder weather in 2008 compared to 2007.

Deliveries to small industrial customers declined in 2008 compared to 2007 primarily in the forestry sector. Two sawmills in the Western system shut down operations pending recovery of lumber markets while another cut back production levels. Lower demand and lower prices for forest products in North America have resulted in lower deliveries to the forest sector again in

2008. The forest sector has been facing significant issues with low lumber prices, the mountain pine beetle infestation and the strength of the Canadian dollar through the first nine months of 2008. These issues have been exacerbated by deteriorating global economic conditions. In contrast, the economy in the Northeast system service area continues to grow as a result of activity in the oil and gas exploration sector, which is reflected in customer additions in that area.

In addition to the effect of conservation and substitution of energy sources, the Company has experienced a net decrease in the number of customers in the Western system. The poor economic conditions in the Western system service area are believed to be responsible for the majority of the decline in the number of residential customers. Certain small industrial customers also closed down, contributing to the reduced economic activity in the Western system service area and the decline in gas consumption in the small industrial sector.

Other Initiatives

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 other initiatives and prospects in the Western system service area that may have a positive impact in the future on the economic conditions in this service area, including:

- construction of the US\$2 billion modernization of the Rio Tinto Alcan Inc. aluminum smelter in Kitimat;
- construction of the Kitimat LNG Terminal and the KSL Project pipeline;
- commencement of gas transportation service to a proposed floating LNG liquefaction vessel to be located near Kitimat; and
- construction of oil and/or condensate pipelines from Alberta to tidewater at Kitimat.

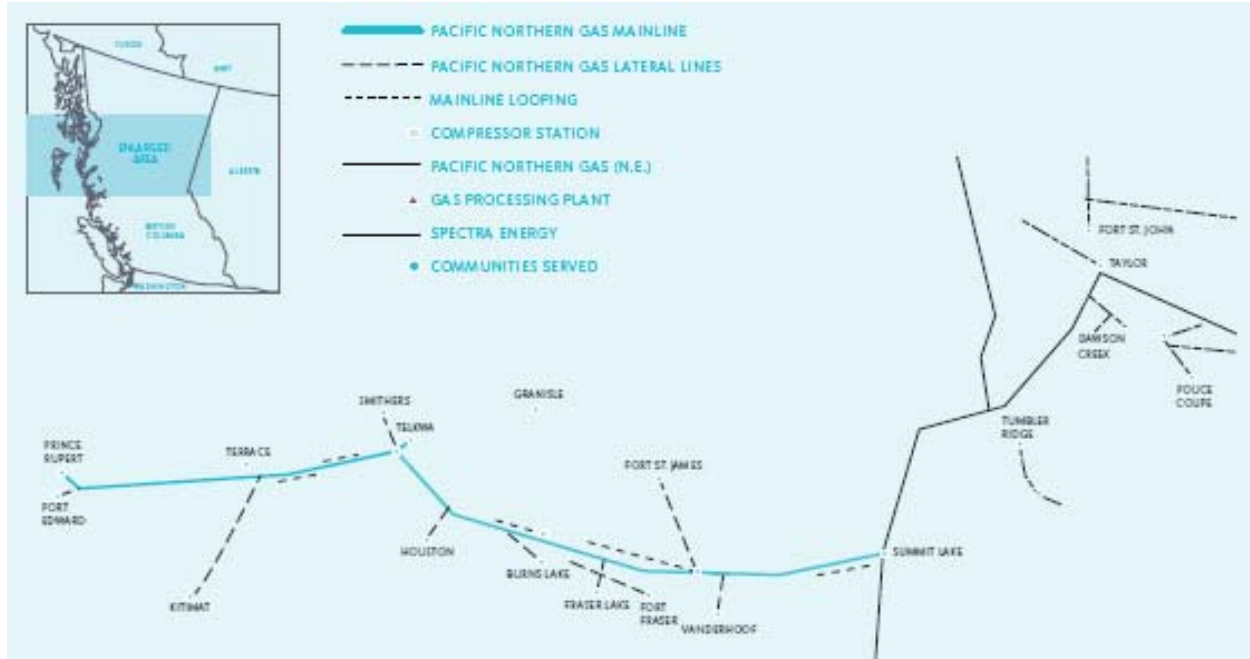
Management can give no assurances that any of the above initiatives will proceed to completion.

In the Company's Northeast system service area there has been continued growth in the oil and gas sector, which has expanded the Company's customer base in that area.

BUSINESS OF THE COMPANY

Overview

The Company's Western system extends from Summit Lake to Prince Rupert and Kitimat. The Northeast system 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.



At year end 2008 the Company was delivering gas to 39,113 residential, commercial and industrial customers. The Company had three large industrial customers in 2008: West Fraser, Rio Tinto Alcan Inc. (“Rio Tinto Alcan”) and British Columbia Hydro and Power Authority (“BC Hydro”). These three customers accounted for 26.2 percent of total gas deliveries and 9.5 percent of the Company’s operating margin during 2008.

The Company’s combined rate base for 2008, as approved by the Commission, was approximately \$168 million.

Gas distributed by the Company to its residential and commercial customers and to certain industrial customers in 2008 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. 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 because a substantial portion of the gas it delivers is used for space heating purposes, resulting in lower sales in warmer months. 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 System

Transmission Pipeline System

The Company's transmission pipeline system in the Western system service area connects with the British Columbia pipeline system operated by Spectra Energy near Summit Lake, British Columbia, and extends 587 kilometers 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 kilometers of lateral transmission pipelines extending into the various communities served by the Company, the most significant being dual lines extending approximately 57 kilometers 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 $3,260 \times 10^3 \text{ m}^3$ (115 MMcf) per day. With the closure of the Methanex methanol/ammonia facility in Kitimat the Company deactivated its compressor stations at Vanderhoof and Telkwa, as well as 53 miles of 10 inch pipeline and 33 miles of 6 inch pipeline. These facilities will continue to be maintained for potential future use, but are not forecast to be utilized in 2009.

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 system service area. The Company's Western system's distribution system is comprised of approximately 1,180 kilometers of distribution pipelines.

The Company currently has exclusive franchise agreements with the municipalities of Prince Rupert, Port Edward, Kitimat, Terrace, Smithers, Burns Lake, Houston, Fraser Lake and Vanderhoof, entitling it to supply and distribute natural gas within those municipalities. 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. Management does not foresee any issues with the renewal of any of the franchise and operating agreements.

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 percent of the Company's gross revenue from sales to residential and commercial customers and 3 percent 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 system service area had a total population of approximately 83,000 at December 31, 2008.

Northeast System

Transmission and Distribution Facilities

The Company's Northeast system serves the Fort St. John and Dawson Creek area through connections with the Spectra Energy pipeline system at several locations. The Northeast 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 to serve the Dawson Creek area and the Spectra Energy pipeline system near Chetwynd, British Columbia to serve the Tumbler Ridge area. The entire Northeast system consists of approximately 160 kilometers of transmission lines, 1,490 kilometers of distribution lines and a gas processing plant near Tumbler Ridge with a capacity of 120 10³m³ per day.

Franchise Agreements

Pacific Northern (N.E.) has exclusive franchise agreements with the District of Taylor and the cities of Dawson Creek and Fort St. John for 21-year terms, expiring in 2012, 2014 and 2018, respectively, as well as an operating agreement with the Village of Pouce Coupe which expires in 2016. The Dawson Creek and Fort St. John agreements provide for payment of a 3 percent fee on gross revenues from sales of gas to residential, commercial, public and institutional customers and 3 percent of the gross revenue from the sale of the first 328,000 GJ per year to any industrial customer. Pacific Northern (N.E.) 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 agreements with the District of Taylor and City of Fort St. John give the municipalities 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 Northeast system had a total population of approximately 57,000 at December 31, 2008.

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 kilometers

of main pipelines and approximately nine kilometers 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 12.5 PJ in 2008 compared with 13.2 PJ in 2007. Deliveries to large industrial sales and transportation customers decreased 15.1 percent from 2007 to 2008, primarily as a result of reduced deliveries to West Fraser which accounted for 69 percent of large industrial customer deliveries in 2008. These reduced deliveries related to the lower demand and lower prices for forest products in North America and the issues faced by the forest sector generally in 2008 with declining economic conditions. However, deliveries to other large industrial customers which accounted for the remaining 31 percent also decreased by 17 percent in 2008 compared to 2007, mainly due to decreased deliveries to BC Hydro which did not operate its Prince Rupert electric power generating station for base load in 2008 but did so in 2007 following damage to their transmission line serving Prince Rupert.

Deliveries to small industrial customers increased slightly by 1.5 percent compared to 2007. Low lumber prices and the reduced housing starts continue to negatively impact lumber production levels and continue to slow down the forestry sector.

Deliveries to residential customers in 2008 also remained at similar levels to 2007 figures, even though weather was approximately 3 percent colder in 2008 compared to 2007. Deliveries to commercial customers increased in 2008 by approximately 5.8 percent from 2007 levels due partly to the colder weather, customer additions and the switch of some transportation customers to sales customers. Commercial transportation service deliveries decreased from 2007 to 2008 primarily due to several commercial transportation service customers converting back to sales customers in the latter part of 2007 due to the failure of a gas marketer.

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>2008</u>	<u>2007</u>	<u>2006</u>
Deliveries (in terajoules):			
Residential	3 210	3 213	3 066
Commercial	3 007	2 904	2 863
Small industrial.....	3 049	3 234	3 484
Large industrial.....	3 276	3 859	2 982
Total energy delivered	<u>12 542</u>	<u>13 210</u>	<u>12 395</u>
Customers at Year End:			
Residential	33,862	33,943	33,904
Commercial	5,190	5,026	5,009
Small industrial.....	58	56	54
Large industrial.....	3	3	3
Total number of customers	<u>39,113</u>	<u>39,028</u>	<u>38,970</u>
Revenue (Dollars in thousands):			
Sales Revenue			
Residential	\$44,937	\$41,589	\$44,919
Commercial	31,974	28,373	34,241
Small industrial.....	4,486	4,327	7,152
Large industrial			
Rio Tinto Alcan.....	4,025	4,451	5,087
BC Hydro.....	—	—	—
Off system sales	32,508	36,083	32,713
Total sales revenue.....	<u>117,930</u>	<u>114,823</u>	<u>124,112</u>
Cost of sales.....	<u>(86,124)</u>	<u>(84,446)</u>	<u>(91,118)</u>
Operating margin from sales	<u>31,806</u>	<u>30,377</u>	<u>32,994</u>
Transportation Revenue			
Residential.....	—	—	—
Commercial.....	1,794	1,472	630
Small industrial	2,832	2,998	3,308
Large industrial			
Methanex	—	—	1,822
West Fraser.....	2,273	2,018	2,017
Rio Tinto Alcan.....	906	832	842
BC Hydro	89	89	86
Off system sales	—	—	—
Total transportation revenue / operating margin from transportation.....	<u>7,894</u>	<u>7,409</u>	<u>8,705</u>
Other Revenue			
Methanex termination payment	6,592	6,752	5,552
Miscellaneous revenue	423	480	479
Total Other Revenue	<u>7,015</u>	<u>7,232</u>	<u>6,031</u>
Total operating margin	<u>46,715</u>	<u>45,018</u>	<u>47,730</u>

Large Industrial Customers

Overview

The Company currently has transportation service agreements with West Fraser and Rio Tinto 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 Company had a transportation service agreement with Methanex covering the period November 1, 2002 through October 31, 2009; however Methanex served notice to terminate its agreement with the Company effective February 28, 2006, as discussed below.

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). A unit demand toll of \$0.85 per GJ applied for the first five years of the term of the agreement, ending on December 31, 2008. For the second five years of the term, commencing January 1, 2009, the toll has been adjusted by 50 percent of the change in the British Columbia Consumer Price Index over the five year period ending December 31, 2008, to \$0.8908/GJ. West Fraser pays a minimum monthly demand charge equal to the unit demand toll times the contract demand times the number of days in the month regardless of the level of actual deliveries. 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 2 percent of deliveries to West Fraser (reduced from 4 percent prior to January 2007). During 2008, deliveries to West Fraser accounted for approximately 18.1 percent of the Company's total gas deliveries and 1.5 percent of operating revenues.

The agreement with West Fraser expires as of December 31, 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. West Fraser had the ability to terminate the agreement with no buy-out payment effective January 1, 2009 by giving the Company notice of termination prior to July 1, 2008 if West Fraser had permanently shut down the Kitimat mill or had commenced the process of permanently shutting down the Kitimat mill prior to January 1, 2009. The Company did not receive a notice of termination.

Lower demand and lower prices for forest products in North America have resulted in lower deliveries to the forest sector again in 2008. The forest sector has been facing significant issues with low lumber prices, the mountain pine beetle infestation and the strength of the Canadian dollar through the first nine months of 2008. These issues have been exacerbated by deteriorating global economic conditions. See "Risk Factors".

Rio Tinto Alcan

Under the terms of its agreement with Rio Tinto Alcan, the Company provides firm gas transportation service to Rio Tinto 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 percent of the monthly contract demand volume multiplied by the firm transportation toll. The agreement also provides for interruptible sales of gas to Rio Tinto 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 one contract year notice of termination. No termination notice has been given.

During 2008, deliveries to Rio Tinto Alcan accounted for 7.9 percent of the Company's total gas deliveries and 3.8 percent of operating revenues. Rio Tinto Alcan has produced aluminium for export from its Kitimat facility since 1952.

In August 2006, Rio Tinto Alcan announced its intention, subject to certain conditions, to modernize the Kitimat facility through an approximate US\$2 billion investment, which would increase Rio Tinto Alcan's annual global primary aluminium production by more than 3 percent. Management expects that, if the project is completed, Rio Tinto Alcan's natural gas requirements would increase when the new capacity comes on-stream. Due to lower demand and prices for aluminum and the global economic downturn, preliminary work on the modernization project is now proceeding at a much slower pace. The Company can give no assurances that the modernization project will be completed.

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 with an annual gas requirement in the range of 24 TJ to maintain the facility in a ready to operate mode. Deliveries totalled 7 TJ in 2008, compared to 218 TJ in 2007 as the facility was operated in April 2007 after an avalanche damaged BC Hydro's electricity transmission line serving Prince Rupert.

Methanex

Transportation service to Methanex in 2005 was provided pursuant to an agreement that was to expire on October 31, 2009. On August 30, 2005, Methanex gave notice of termination of the agreement. Pursuant to the terms of the agreement, Methanex made a termination payment to the Company of approximately \$23.3 million on February 28, 2006, the effective date of the termination. This termination payment was 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. Under the terms of a negotiated settlement with registered intervenors and approved by the Commission on November 17, 2005, the termination payment was recorded as an interest bearing credit deferral, and is being amortized into income over the period March 1, 2006 to October 31, 2009.

Transportation service revenue in 2006 from Methanex was \$10.4 million lower than in 2005 due to the termination of the agreement with Methanex. This reduction was offset by credit amortization of \$5.6 million of the contract termination payment in 2006 resulting in a net

margin reduction of \$4.8 million. The Company sought and obtained Commission approval in its 2006 revenue requirements application to recover an estimated \$4.8 million in net margin reduction in 2006, due to the Methanex agreement termination, from its remaining customers and made similar applications in 2007 and 2008. The Company is seeking Commission approval in its 2009 revenue requirements application to recover \$1.1 million in response to the impact of the full amortization in rates of the Methanex termination payment as of October 31, 2009.

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 number of 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. In addition, some of the Company's smaller commercial customers purchase their gas supply requirements directly from gas marketers. Since the Company earns income from the distribution of natural gas and not from the sale of the commodity, the Company's distribution margin is not adversely affected by this practice. 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 may be sold either on an interruptible basis to industrial customers or sold to other purchasers who are not the Company's transmission or distribution customers ("off system sales"). Any profit or loss realized on off system gas sales is deferred for future recovery from, or refund to, the Company's sales customers.

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.

For 2008, approximately 41 percent of gas purchases were hedged pursuant to the Company's gas price management plan. A gas supply contracting plan is prepared annually and filed with the Commission for review prior to finalizing annual gas purchase arrangements. The gas contracting plan is designed to ensure the Company has adequate gas supplies to meet the requirements of its customers on the coldest day of the year, normally referred to as "the peak day". Contracted gas that is surplus to customer requirements on any particular day is sold into

other markets at prevailing market prices through off-system gas sales. Most of the Company's contracted gas supply is produced in British Columbia.

Most of the gas purchased by the Company from its gas suppliers is taken from the pooled gas stream available from the Spectra Energy pipeline system. This includes all of the supply to the Company's transmission line serving its Western system service area and approximately 74 percent of the supply for the Fort St. John and Dawson Creek service areas.

In addition to the supply from the Spectra Energy system, the Fort St. John system incorporates two interconnections with CNRL's West Stoddart Pipeline, providing 35 percent of that system's requirements. In Dawson Creek, approximately 8 percent of the required supply is received from a local producer of sweet (pipeline quality) gas at a point where its system intersects the Company's transmission line. In Tumbler Ridge, all of the gas supply is obtained in the form of raw gas production from CNRL and the Company operates its own gas processing facilities.

In 2008, gas was purchased under a number of short term seasonal, base load and spot gas supply arrangements. Short term gas supply contracts are in keeping with current industry practices.

Customer Additions

Customer additions in 2008 amounted to a net increase of 85 customers, being comprised of a net loss of 185 customers in the Western system service area and a net gain of 270 customers in the Northeast system service area.

During 2008, PNG determined that it should revise its methodology used to count customers to exclude installed natural gas services where deliveries could not occur as a result of the meter having been locked off by the Company. The Company also restated its customer count for prior years, in order to reflect the same methodology as has been implemented in 2008. As a result the customer count as at year end 2007 was reduced by 545, from 39,573 reported last year to the revised 39,028 figure, a reduction of about 1.4 percent.

In the Western system service area, there are few remaining candidates for conversion to natural gas in existing homes and businesses and limited opportunity to extend gas mains into unserved rural areas. Also, with the exception of the Northeast system, 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 in the Western system service area.

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, including 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 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 benchmark low-risk utility based on forecast long term Government of Canada bond rates plus a risk premium. The Company's risk profile is compared by the Commission to the benchmark low-risk utility to determine the Company's utility-specific risk premium relative to the ROE applicable to the benchmark low-risk utility. The Company's utility-specific risk premium is then added to the benchmark low-risk 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 is set by the Commission's formula 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 the ensuing 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 the three service areas (the Western system service area and two service areas in the Northeast system) are submitted to the Commission, generally on an annual basis. The Northeast system 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. Settlements are subject to final approval by the Commission.

The 2008 revenue requirements applications for each division were filed with the Commission in early October 2007. The Company and its customers negotiated settlements of the 2008 revenue requirements applications and the settlements were approved by the Commission in late December 2007. As a result, the Company was able to set new rates effective January 1, 2008 on a permanent basis.

The 2009 revenue requirements applications for each of the Company’s divisions were filed with the Commission in late November 2008 for approval of new rates to take effect January 1, 2009. The Commission approved interim rates effective January 1, 2009 at the levels set forth in the applications and set down a negotiated settlement process to commence on March 23, 2009.

Descriptions of the the key elements of the negotiated settlements for 2008 and of the 2009 applications are described below for each division.

Western System

The 2008 allowed rate of return on common equity for the Western system was 9.27 percent reflecting a 65 basis point premium over the low risk benchmark utility rate of return and based on a deemed common equity component of rate base of 40 percent.

Under the 2008 negotiated settlement, the agreed upon rate increase was approximately 4.2 percent for the average residential customer. This increase included the impact of continuing to credit \$0.9 million of deferred income taxes to the 2008 cost of service, the same level of credit approved by the Commission with respect to the 2007 cost of service.

The gas supply commodity charge component of rates declined as of January 1, 2009 compared to the rates effective October 1, 2008. The Commission reviews the gas supply commodity charges on a quarterly basis. The next potential change to the gas supply charge in rates will be April 1, 2009.

The forecast 2009 residential and commercial deliveries contained in the 2009 revenue requirements application for the Western system are approximately 3.8 percent lower than actual gas deliveries to these customer classes in 2008. The reduced forecast reflects expected conservation efforts and the lower number of customers. Deliveries to small industrial customers are projected to be approximately 8.9 percent lower in 2009 compared to actual gas deliveries in 2008. The decrease is primarily due to some sawmills installing waste wood burners and reduced lumber production due to low lumber prices and the global economic downturn.

Prior to the commencement of each calendar year, the Commission resets the allowed rate of return on common equity for each of the Company's regulatory divisions by a formula which uses, among other things, a consensus forecast of yields on 10-year Government of Canada bonds for the forthcoming year. Largely as a result of the lower 10-year bond yields which were in effect in the latter part of 2008 relative to the same period in 2007, the consensus forecast of 2009 10-year bond yields decreased relative to the late 2007 consensus forecast of 10-year bond yields for 2008. Through application of the formula the approved rates of return on common equity for the Company have decreased. In November 2008, the Commission confirmed that the formula resulted in an 8.47 percent rate of return for a low risk benchmark utility in 2009 resulting in an allowable rate of return on common equity of 9.12 percent applicable to the Western system for 2009.

Northeast System

Fort St. John/Dawson Creek Division

The Fort St. John/Dawson Creek division allowed 2008 return on common equity was 9.02 percent with a deemed common equity component of 36 percent. The allowed rate of return on common equity includes a premium of 40 basis points over the low risk benchmark utility rate of return for the Fort St. John/Dawson Creek division.

The 2008 negotiated settlement contained minor adjustments to the applied for 2008 cost of service for rate making purposes. The negotiated settlement provided for an increase of approximately 2.9 percent for the average residential customer in the Fort St. John/Dawson Creek division.

The forecast 2009 residential and commercial deliveries contained in the 2009 revenue requirements application for the Fort St. John/Dawson Creek system are approximately 0.8 percent higher than actual gas deliveries to these customer classes in 2008. Deliveries to small industrial customers are projected to be approximately 5.3 percent lower in 2009 compared to actual gas deliveries in 2008. The reduction in small industrial deliveries is attributable to a sawmill converting to a new energy system in 2009.

The gas supply commodity charge component of rates for the Fort St. John/Dawson Creek division declined as of January 1, 2009 compared to the rates effective October 1, 2008. The Commission reviews the gas supply commodity charges on a quarterly basis. The next potential gas supply charge rate changes will be determined as of April 1, 2009.

The Commission's automatic return on equity adjustment formula resulted in an allowable rate of return on common equity of 8.87 percent applicable to the Fort St. John/Dawson Creek division for 2009.

Tumbler Ridge Division

The Tumbler Ridge division allowed 2008 return on common equity was 9.27 percent with a deemed common equity component of 36 percent. The allowed rate of return on common equity includes a premium of 65 basis points over the low risk benchmark utility rate of return for the Tumbler Ridge division.

The 2008 negotiated settlement contained minor adjustments to the applied for 2008 cost of service for rate making purposes. The negotiated settlement provided for a rate decrease of approximately 3.8 percent for the average residential customer in the Tumbler Ridge division.

The gas supply commodity charge component of rates for the Tumbler Ridge division declined as of January 1, 2009 compared to the rates effective October 1, 2008. The Commission reviews the gas supply commodity charges on a quarterly basis. The next potential gas supply charge rate changes will be determined as of April 1, 2009.

The Commission's automatic return on equity adjustment formula resulted in an allowable rate of return on common equity of 9.12 percent applicable to the Tumbler Ridge division for 2009.

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 four years ended December 31, 2009:

	Years ended December 31			
	2009	2008	2007	2006
Western system:				
Rate base.....	\$130,654*	\$132,938	\$131,628	\$131,210
Common equity component.....	40.0%	40.0%	40.0%	40.0%
Allowed return on common equity	9.12%	9.27%	9.02%	9.45%
Fort St. John/ Dawson Creek division:				
Rate base.....	\$35,346*	\$33,486	\$31,966	\$30,095
Common equity component.....	36.0%	36.0%	36.0%	36.0%
Allowed return on common equity	8.87%	9.02%	8.77%	9.20%
Tumbler Ridge division:				
Rate base.....	\$1,632*	\$1,465	\$1,360	\$1,153
Common equity component.....	36.0%	36.0%	36.0%	36.0%
Allowed return on common equity	9.12%	9.27%	9.02%	9.45%

*estimate

Engineering and Operations

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 requirements to make any material capital expenditures for environmental compliance during 2009. The Company did not incur any specific expenditures on research and development during 2008 and does not expect to do so in 2009.

The Company's 2009 revenue requirements applications to the Commission included \$0.65 million for the estimated cost of replacing an underwater transmission line crossing of Porpoise Harbour located near Prince Rupert, B.C. with a line installed on land. This project will ensure the ongoing integrity of these facilities and eliminate the underwater crossing.

Programs have been implemented to ensure adherence to the Company's environment, health and safety policies. The programs include environmental training for specific employee groups, implementation of environmentally sound construction practices including on-site environmental monitoring where appropriate, and a continuing focus on corporate due diligence. The Board of Directors oversees the Company's environment, health and safety responsibilities through the Environment, Health and Safety Committee.

In-Line Inspection

The Company has processes in place to monitor the ongoing integrity of its transmission pipeline systems 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 in-line inspection program is predominantly based on running a Magnetic Flux Leakage (“MFL”) tool that is primarily used to detect metal loss due to external and internal corrosion. This tool can also detect certain other potential defects including defects in the pipe wall such as laminations, and certain types of weld defects. After the MFL tool runs are complete, the resulting information is processed and evaluated to determine which areas need rehabilitation. The 2008 in-line inspection activity involved running an MFL tool through a total of 132 kilometers of ten-inch, twelve-inch and sixteen-inch diameter sections of transmission pipeline. The final results of this inspection activity are not yet available, but are expected to be favourable and will continue to be supported by subsequent investigations to confirm the integrity of the inspected sections of the line. The Company intends to continue its in-line inspection program in 2009 and into the foreseeable future on an annual basis.

Employees

At December 31, 2008, the Company had 102 employees, comprised of 76 unionized and 26 non-unionized employees. All unionized employees are members of the International Brotherhood of Electrical Workers (the “Union”). The Company’s collective agreement with the Union expired on October 31, 2007 and was successfully renegotiated with a new expiry on October 31, 2012.

RISK FACTORS

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

Usage Risk and Impact of Changes in Economic Conditions

Natural gas competes with other forms of energy available to the Company’s customers and end-users, including electricity, wood and coal and, in the case of certain industrial customers, wood waste. The primary competitive factor is price. Changes in the availability or price of natural gas and other forms of energy, economic conditions, the level of business activity, conservation, legislation, governmental regulations, the ability to convert to alternative fuels, weather and other factors affect the demand for natural gas in the Company’s service areas. In addition, because electricity prices in British Columbia for residential and certain other customer classes have been set based primarily on the historical average cost of production, they have been artificially low compared to market priced natural gas. This distortion in pricing signal may be addressed in response to the British Columbia government’s Energy Plan electricity conservation goals.

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

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

In particular, economic conditions in the Company's service areas affect the Company's results of operations and financial condition. Deliveries are affected by economic factors such as changes in employment levels, personal disposable income and level of business activity. New customer additions are related to the level of business activity, population growth and housing starts in the service area. Many of these factors are being affected by deteriorating economic conditions and the uncertainty of future developments in the domestic and global economies. Management cannot estimate the level of growth or contraction for the economy as a whole or for the economy of any particular region the Company serves. Adverse changes in the Company's financial condition and results of operations may occur as a result of continuing negative economic conditions, a decline in business activity, unemployment, contraction of credit availability or other factors affecting economic conditions generally.

KSL Project

On July 17, 2006, the Company announced the formation of PTP for the purpose of developing the KSL Project. In addition, PTP and Kitimat LNG Inc. executed a Precedent Agreement to coordinate the process of obtaining authorizations for the KSL Project with the development of the LNG export terminal. Upon completion of the KSL Project, and subject to regulatory and shareholder approvals, the Company's existing mainline transmission system will be transferred to PTP and integrated with the KSL Project facilities. The Company will continue to own and operate its existing gas distribution systems, including its Customer Care Centre in Terrace. Construction of the KSL Project facilities is scheduled to commence in 2011 for completion in 2013.

Construction of the KSL Project is subject to a number of conditions including the securing of contracts by Kitimat LNG and PTP for utilization of capacity at the LNG export terminal and the KSL Project facilities respectively, financing of both projects and regulatory approvals for the KSL Project. The Company can give no assurances that these conditions will be met or that the construction of the LNG export terminal by Kitimat LNG and the construction of the KSL Project by PTP will proceed. If construction of the KSL Project does not proceed, and without development of other strategic initiatives, the Company will remain reliant on its existing customer base and assets. The risks associated with the existing customer base and assets are described in the other risk factors in this section, particularly those found under the headings Commodity Price and Supply Risks, Usage Risks and Potential for Termination of Large Industrial Contracts.

As noted in the General Development of the Business section of this form, Management expects that the Company's share of development expenditures on the KSL Project will be approximately \$0.2 million (\$0.14 million after income taxes) in 2009. However, development costs incurred during this period may be higher than expected.

Liquidity, Cash Flow and Capital Availability Risks

The Company has several credit facilities, including a \$20 million operating line, a \$20 million 5-year term revolving credit facility and a \$15 million risk management facility. The operating line, which is available for working capital requirements, is subject to borrowing base requirements and a financial covenant which may act to restrict the amount the Company can borrow under the operating line. The financial covenant requires the Company to maintain a debt to capitalization ratio of 65 percent or less. At December 31, 2008 the Company's debt to capitalization ratio was under 50 percent. See "Management's Discussion and Analysis – Capital Resources – Short Term Debt". At December 31, 2008 the borrowing base was approximately \$20.3 million and the Company had utilized \$15.9 million of the operating line by way of overdraft on the operating line and outstanding letters of credit in the amount of \$12.9 million issued under the line to secure certain gas purchase obligations as well as the Company's obligations under its unfunded supplemental retirement plan. The letters of credit reduce the amount available under the operating line by their face value. The operating line is collateralized by a charge on the Company's accounts receivables and inventories.

The current global economic conditions have had significant adverse impacts on financial markets, including those markets accessed by the Company to maintain liquidity. The Company's operating line and risk management facility are renewed on an annual basis and mature in July of 2009. Based on discussions with its lender, the Company expects that it will continue to have access to these sources of liquidity, however, it also expects that the credit spreads and fees that apply to its operating line may increase significantly at the time of renewal. Further, its lender may also require additional financial covenants which could restrict the Company's borrowing flexibility.

The \$20 million 5-year term revolving credit facility was arranged effective August 3, 2007 through Canadian Western Bank and Roynat Inc., each committing \$10 million. This facility, which is available for general corporate purposes, also contains a financial covenant requiring the Company's debt to capitalization ratio not to exceed 65 percent. Further, if the Company's secured debt rating is less than BBB (low) or the Company has no debt rating, an additional financial covenant comes into effect requiring the Company to maintain an interest coverage ratio of 2.0 or higher using earnings before interest, income taxes and expenditures, to a maximum of \$10 million, on the KSL Project. While the covenant did not apply in 2008 as the Company's debt rating was BBB (low), the Company's interest coverage at December 31, 2008 was 2.14. This credit facility is collateralized by the pledge of a \$20 million debenture issued under the Company's Deed of Trust and Mortgage. The Company had \$6 million outstanding under this facility at December 31, 2008. Additional funds available under this facility will be used for general corporate purposes, including the Company's capital program, and for expenditures on the KSL Project.

The Company purchases gas for resale to its gas sales customers and passes through the commodity cost of gas to those customers without mark-up. The rates charged to gas sales customers are based, in part, on projected gas supply prices. The Company's liquidity requirements can be affected by delays between increases or decreases in the cost of gas purchased by the Company and regulatory approval of rate adjustments to reflect the cost increases or decreases. The Company utilizes its \$15 million risk management facility to enter

into financial derivative contracts which help mitigate the volatility of its gas purchase costs. This facility is also collateralized by the pledge of a \$20 million debenture issued under the Company's Deed of Trust and Mortgage.

The Company requires long term debt to fund a portion of its capital and KSL Project development expenditures as well as scheduled debt amortization payments. On July 25, 2007 the Company's existing term lender Roynat Inc. refinanced its holdings of \$14 million of the Company's debentures that were scheduled to mature in 2011 and 2012, with a new \$15 million debenture issue maturing in 2017.

Any constraint on the Company's ability to access capital, including a credit downgrade, may negatively impact its investment and development activities, capital expenditures and hedging program.

Commodity Price and Supply Risks

The commodity cost of natural gas can be highly volatile. The Company's average cost of natural gas in 2008 was approximately 1 percent higher than in 2007 and 1 percent lower than in 2006. When prices are low, the prospects of fuel-switching and increased energy conservation to other energy sources that can be more cost competitive pose a lesser risk. Fluctuations in the price of natural gas may increase the Company's working capital financing requirements and related costs for accounts receivable, and may give rise to higher bad debt costs.

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

Potential for Termination of Large Industrial Contracts

In 2008, approximately 26.1 percent of energy deliveries were made to the Company's two largest industrial customers, Rio Tinto Alcan and West Fraser, representing approximately 9.3 percent of the consolidated operating margin of the Company. The Company's contract with West Fraser expires at the end of 2013 and may be terminated prior to that date upon payment of an amount described in the contract. In 2008, deliveries to West Fraser accounted for 18.1 percent of the Company's total gas deliveries and 1.5 percent of operating revenues. The initial term of the Company's agreement with Rio Tinto Alcan 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 2008, deliveries to Rio Tinto Alcan accounted for 7.9 percent of the Company's total gas deliveries and 3.8 percent of operating revenues. 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 Company's service area is dependent upon industrial customers for its economic stability. These customers produce commodities that are subject to world commodity fluctuations and are

impacted by current deteriorating economic conditions. The Company's gas deliveries to these customers have been and may in the future be affected by their ability to continue to operate in negative economic conditions and during sustained periods of low commodity prices. A prolonged decline in a sector affects all customer classes. For example, in the Western system service area many of the Company's industrial customers are involved in the forest sector. The forest sector has been facing significant issues with low lumber prices, the mountain pine beetle infestation and the strength of the Canadian dollar through the first nine months of 2008. These issues have been exacerbated by deteriorating global economic conditions. 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.

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 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 deductible for pipeline breaks is relatively high at \$2 million per event. 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.

Subsequent to the ratification of the Kyoto Protocol in December, 2002, the pace of regulatory developments that address the problems of stabilizing and then reducing anthropogenic carbon emissions into the atmosphere has been increasing. Several emissions reduction schemes are now in operation including the European Emissions Trading System (2005), the Regional Greenhouse Gas Initiative (2009), and the Alberta-based Offset Credit System (2007). In addition, draft regulations for the Canadian federal government's 2007 regulatory framework on industrial greenhouse gas emissions are expected in the the first quarter of 2009 with the final version expected in the fall 2009 prior to coming into force on January 1, 2010 . The British Columbia Ministry of Environment intends to introduce a Mandatory Reporting of Greenhouse Gas Emissions Regulation ("GHG Reporting Regulation") to support the Greenhouse Gas Reduction (Cap and Trade) Act. It is anticipated that this regulation will come into effect in 2009. The GHG Reporting Regulation will set out requirements for the reporting of greenhouse gas emissions to the Ministry. It will also support the implementation of a cap and trade system harmonized with those of the member states of the Western Climate Initiative which are expected to come into effect no later than 2012.

Based on the applicable emissions thresholds set out in the draft federal and provincial regulations, the Company expects its compliance obligations to be small or even non-existent. However, as the federal and provincial regulations remain in development, it is not possible at this time to assess the full extent of their impact on the Company. In addition, the effects of climate change on the Company's service territories over the long term may manifest themselves in changes to customers' consumption patterns, as well as to changes in the level and nature of

geotechnical and hydrological threats to the Company's pipeline systems. The Company recognizes the entire spectrum of influences that climate change may exert on its operations and continues to monitor, and influence as appropriate, related policies, regulations and developments.

Derivatives Risk

The Company utilizes derivative and other financial instruments in connection with the management of gas supply and may in the future use these instruments for the management of 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 or the failure of a counterparty to a derivative instrument. These risks could affect the Company's liquidity and regulatory approval would be required for the Company to recover related costs through future rate adjustments. 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.

Human Resources Risks

Most of the employees of the Company are members of a union. 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.

Employee Future Benefits Plan Risk

The Company has a defined benefit pension plan for the majority of its employees and retirees. Contributions to the plan are established by actuarial valuations prepared every three years and filed with the appropriate regulatory authorities. The most recently filed valuation was prepared on December 31, 2006. The next valuation is required to be prepared at December 31, 2009 and will determine the contributions required from 2010 onwards. If the plan continues to experience negative returns or fails to recover the market losses incurred in 2008, it may result in large contribution requirements beyond 2009.

First Nations Matters

First Nations groups have claimed rights and title 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 kilometers of the Company's main pipeline and approximately nine kilometers of lateral transmission pipelines cross reserves established under the *Indian Act* (Canada). The impact upon the Company of treaties or settlements with First Nations 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, and in particular the current global financial issues, 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 and deemed equity. 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>2008</u>	<u>2007</u>	<u>2006</u>
Dividends per share			
- common	\$0.88	\$0.80	\$0.80
- preferred	\$1.69	\$1.69	\$1.69

On March 4, 2009 the Board of Directors approved an increase in the quarterly dividend to \$0.23 per Common Share payable March 23, 2009 to shareholders of record at the close of business on March 16, 2009. 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 6¾ percent cumulative redeemable preferred shares with a par value of \$25 each (the "Preferred Shares"). There are 3,664,580 Common Shares, no Junior Preferred Shares and 200,000 Preferred Shares issued and outstanding at March 4, 2009.

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 Percent Cumulative Redeemable Preferred Shares

The Preferred Shares are entitled to the payment of fixed cumulative preferential cash dividends at the rate of 6 ¾ percent 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

Through 2008, the Company's preferred shares were rated Pfd-3(low) by Dominion Bond Rating Service ("DBRS") and the Company's secured debentures were rated BBB(low), both with a negative trend. On January 23, 2009, DBRS confirmed the Company's secured debt and preferred share ratings at BBB(low) and Pfd-3(low) respectively, both with a negative trend.

In its January 23, 2009 press release confirming the Company's ratings, DBRS noted the following:

"The favourable 2006 British Columbia Utilities Commission (BCUC) decision on the Methanex termination was key in maintaining PNG's financial and credit profile. However, the Methanex amortization approved by the BCUC expires in October 2009 and the outcome of PNG's recently filed rate application for increased rates to recover the lost revenue upon expiration remains critical to maintaining a stable financial profile and the current credit rating in the long term.

DBRS has confirmed the ratings and maintained the negative trend, but will look to resolve the trend when the BCUC decision has been rendered. A favorable decision by the BCUC is likely to result in a positive action (change in trend from Negative to Stable), while a negative decision would likely lead to a downgrade of the ratings. Based on the precedent set in the 2006 decision, DBRS expects that PNG will be allowed to recover its full cost of service."

In its ratings report dated January 29, 2009, DBRS noted the following key challenges for PNG in arriving at the ratings for the Company's long term debt and preferred shares:

- Future outcome of BCUC's decision on rates when Methanex amortisation ends in 2009.
- Economic conditions in PNG's Western system service area remains challenging.
- Competitiveness of natural gas versus alternative fuel sources.
- Low interest rate environment negatively impacts earnings through approved return on equity.
- Deemed equity component viewed as low.

Long-term debt rated BBB (ranging from BBB(low) to BBB(high)) is considered by DBRS to be 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 (ranging from Pfd-3(low) to Pfd-3(high)) are also considered by DBRS to be 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.

With respect to the negative trend, DBRS' rating policies published on their web site at www.dbrs.com include the following statements:

- “Rating trends provide guidance in respect of DBRS's opinion regarding the outlook for the rating in question, with rating trends falling into one of three categories – “Positive”, “Stable” or “Negative”. The rating trend indicates the direction in which DBRS considers the rating is headed should present tendencies continue, or in some cases, unless challenges are addressed.”
- “Generally, the conditions that lead to the assignment of a Negative or Positive Trend are resolved within a twelve month period. However, in some instances, new factors emerge which may cause the Positive or Negative Trend to be maintained, even as the original factors become clarified or resolved.”

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 percent Cumulative Redeemable Preferred Shares of the Company are listed on the TSX. The following table sets out the price ranges and volume traded for each month of the fiscal year ended December 31, 2008 for the common shares and the 6 3/4 percent preferred shares:

Common shares:	High	Low	Volume
January	\$18.65	\$ 17.60	89,973
February	18.48	18.02	71,674
March	18.45	17.34	53,509
April	18.30	17.50	70,954
May	18.40	17.88	65,596
June	18.50	17.60	40,793
July	17.75	16.50	32,655
August	17.12	16.35	33,877
September	17.49	16.25	53,359
October	17.25	15.20	94,938
November	16.25	14.20	101,049
December	14.40	12.11	82,672

Preferred shares:	High	Low	Volume
January	\$26.50	\$26.00	800
February	-	-	-
March	26.50	25.50	651
April	25.68	25.68	100
May	27.00	25.70	500
June	25.60	25.60	200
July	25.50	25.15	300
August	26.00	25.25	1,025
September	25.77	25.77	100
October	25.00	24.01	2,775
November	24.95	24.05	950
December	25.00	23.75	2,600

LEGAL PROCEEDINGS

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.

DIRECTORS AND OFFICERS

The following tables set out the names of the directors and officers, 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 3.1 percent of the issued and outstanding common shares of the Company.

Directors

Name, Principal Occupation and Other Information	Beneficial Ownership or Control of Common Shares at March 4, 2009	Number of DSU's at March 4, 2009	Purchase Value of Common Shares and DSU's ⁽⁶⁾
Robert F. Chase: Chair of the Board; President and Chief Executive Officer of New West Energy Services Inc. (formerly Lexacal Investment Corp.) (an oil and gas services company); resident in British Columbia, Canada; a director of the Company since April 26, 1995 ^{1, 4, 5}	Nil	5,530.608	\$95,390
Wayne M. Bingham: Executive Vice-President and Chief Financial Officer, Superior Plus Corp.; resident in Alberta, Canada; a director of the Company since April 26, 2007 ^{2, 4}	3,300	1,431.550	\$80,257
Roy G. Dyce: President and Chief Executive Officer of Pacific Northern Gas Ltd.; resident in British Columbia, Canada; a director of the Company since April 29, 1982	68,227	--	Note 7
Diane M. Fulton: Vice President, Chief Investment Officer, Vancouver Foundation (a not-for-profit community foundation); resident in British Columbia, Canada; a director of the Company since August 8, 2005 ^{2, 5}	Nil	1,883.251	\$32,191
Robert B. Johnston: Executive Vice President and Chief Strategy Officer, The InterTech Group (a holding company and operator of diverse, global group of companies) ; resident in South Carolina, U.S.A.; a director of the Company since June 9, 2008	3000	917.580	\$56,323
Hugh C. Morris: Corporate Director; resident in British Columbia, Canada; a director of the Company since May 1, 1986 ^{1, 3}	400	1,965.040	\$37,643

Name, Principal Occupation and Other Information	Beneficial Ownership or Control of Common Shares at March 4, 2009	Number of DSU's at March 4, 2009	Purchase Value of Common Shares and DSU's ⁽⁶⁾
David G. Unruh: Corporate Director; resident in British Columbia, Canada; a director of the Company since March 21, 2002 ^{3,4}	Nil	2,884.313	\$50,208
Arthur H. Willms: Corporate Director; resident in British Columbia, Canada; a director of the Company since April 28, 1983 ^{1,5}	Nil	1,994.91	\$34,168
Janet P. Woodruff: Interim President, BC Transmission Corporation (a Crown corporation that plans, operates and maintains the province's publicly owned electrical transmission system); resident in British Columbia, Canada, a director of the Company since February 16, 2006 ^{2,3}	Nil	1,217.097	\$20,783

(1) Member of the Executive Committee

(2) Member of the Audit Committee

(3) Member of the Environment, Health and Safety Committee

(4) Member of the Corporate Governance Committee

(5) Member of the Human Resources and Compensation Committee

(6) Effective January 1, 2007, the Company established a Deferred Share Unit Plan (the "DSU Plan") to align the interests of the directors with those of the shareholders. Under the DSU Plan, directors may designate a percentage (25, 50, 75 or 100 percent) of his or her total compensation to be issued as DSU's. In addition, the Board of Directors approved recommended share ownership guidelines for directors equal to three times the annual retainer (currently \$17,500) to be attained within five years of the Company's 2007 Annual Meeting or, for new directors, within (i) five years from the date of such director's appointment if at an Annual Meeting, and (ii) within five years from the date of the next Annual Meeting following such director's appointment if such appointment is not at an Annual Meeting. The ownership guidelines are measured by the purchase value of shares and DSU's.

(7) Mr. Dyce's shares have been acquired primarily through stock option exercises over a number of years and the purchase value is difficult to calculate. At the closing price of the Company's shares on March 4, 2009 of \$11.50 these shares had a market value of \$784,610.

Officers

Name, Position and Other Information	Beneficial Ownership or Control of Common Shares at March 4, 2009
<u>Robert F. Chase</u> Chairman of the Board British Columbia, Canada	Nil
<u>Roy G. Dyce</u> President and Chief Executive Officer British Columbia, Canada	68,227
<u>Greg B. Weeres</u> Vice President, Operations and Engineering, British Columbia, Canada	15,238
<u>Janet P. Kennedy</u> Vice President, Finance British Columbia, Canada	Nil
<u>Kevin R. Teitge</u> Vice President, 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	8,538
<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. Woodruff was Chief Financial Officer and Vice President Systems Development and Performance of Vancouver Coastal Health from 2003 to September 2007; Mr. Bingham was Executive Vice President and Chief Financial Officer for Finning International Inc. from 2003 to 2006; Ms. Fulton was Executive Director – Investments of the Faculty Pension Plan of the University of British Columbia from 1999 to October 2008; Ms. Kennedy was a financial consultant to Terasen Inc. from May, 2006 to September, 2007 and was Director, Financial Planning and Projects for Terasen Inc. from March 2002 to November 2005; Ms. K.E. Stark-Anderson is engaged in the practice of law through KSA Law Corporation and from 2002 to 2006

was Assistant General Counsel and Corporate Secretary of Westcoast Energy Inc.

To the knowledge of management, except as described below, none of the individuals named above is at the date hereof or has been within the past ten years: (i) a director, chief executive officer or chief financial officer of any company that, while such individual was acting in such capacity, was the subject of or was the subject of an event that resulted in, after such individual ceased to act in such capacity, an order within the meaning of Form 51-102F5 of National Instrument 51-102 - *Continuous Disclosure Obligations*; (ii) a director or executive officer of any company that, while such individual was acting in such capacity or within a year of such individual ceasing to act in such capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or (iii) been bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or became subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold any of his or her assets:

Mr. Chase is currently and was a director of New West Energy Services Inc. (“New West”) when, on September 5, 2006, a cease trade order was issued against New West by the British Columbia Securities Commission for failure to file its financial statements within the prescribed time. The default was rectified and the order was rescinded on November 9, 2006.

To the knowledge of management, none of the individuals named above has been subject to any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable security holder in deciding whether to vote for such individual as a director of the Company.

Audit Committee

Charter of the 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.

Composition of the Audit Committee

Ms. Woodruff, Ms. Fulton and Mr. Bingham served as members of the Audit Committee from January 1, 2008 to December 31, 2008. All members of this Committee are independent as defined under Multilateral Instrument 52-110 “Audit Committees”.

Relevant Education and Experience

Each member of the Audit Committee is financially literate as defined under Multilateral Instrument 52-110 “Audit Committees”.

Ms. Woodruff, the Chair of the Committee, is a chartered accountant and holds a Masters of Business Administration from York University. She has experience in public practice and, for nearly fifteen years, held various senior executive and financial management positions in a large Canadian company prior to becoming Chief Financial Officer of Vancouver Coastal Health Authority, subsequently Chief Financial Officer of BC Transmission Corporation and now Interim President of BC Transmission Corporation. Ms. Woodruff has also completed the Directors' Education Program at the Institute of Corporate Directors.

Ms. Fulton holds a Masters of Business Administration from York University and is a member of the Board of Directors, the Investment Committee and the Audit Committee of the Insurance Corporation of British Columbia. She has over twenty years experience in investment banking and investment fund management. Ms. Fulton has also completed the Directors' Education Program at the Institute of Corporate Directors and earned the ICD.D designation.

Mr. Bingham has over 25 years experience in financial and capital markets. Prior to attaining his current position as Executive Vice President and Chief Financial Officer of Superior Plus Corp., Mr. Bingham served as Executive Vice President and Chief Financial Officer at Finning International Inc. and Ontario Power Generation. In addition, he has held many senior executive and management positions in strategy, financing, compliance, risk management, treasury and supply chain operations. Mr. Bingham holds a Bachelor of Commerce from Laurentian University and a Chartered Accountant designation.

Reliance on Certain Exemptions

Since January 1, 2007, the Corporation has not relied on the exemptions contained in sections 2.4, 3.2, 3.3(2), 3.4, 3.5, 3.6, 3.8 or Part 8 of MI 52-110. Section 2.4 provides an exemption from the requirement that the Audit Committee must pre-approve all non-audit services to be provided by the external auditor, where the total amount of fees related to the non-audit services are not expected to exceed 5% of the total fees payable to the external auditor in the fiscal year in which the non-audit services were provided. Sections 3.2, 3.3(2), 3.4, 3.5, 3.6 and 3.8 provide exemptions relating to the independence and financial literacy requirements for the composition of the Audit Committee in certain circumstances. Part 8 permits a company to apply to a securities regulatory authority for an exemption from the requirements of MI 52-110, in whole or in part.

Audit Committee Oversight

At no time since January 1, 2008 was a recommendation of the Audit Committee to nominate or compensate an external auditor not adopted by the Board.

Pre-Approval Policies and Procedures

The Terms of Reference for the Audit Committee provide that the Audit Committee is required 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 above 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.

External Auditor Service Fees

Except as noted, all dollar amounts herein are in Canadian dollars. Fees, including reimbursements for expenses, for professional services rendered by Deloitte & Touche LLP to the Company were:

	Audit Fees	Audited-Related Fees⁽¹⁾	Tax Fees⁽²⁾	All Other Fees
2008	\$159,000	\$77,910	---	---
2007	\$153,700	\$25,175	---	---

(1) Audit-related fees pertain to quarterly reviews in 2008, attendance at interim audit committee meetings in 2007, consultation on accounting matters, audit of pension and savings plans, and IFRS consultation.

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

INTERESTS OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

The Company had no material transactions with related parties during 2006, 2007 or 2008.

MATERIAL CONTRACTS

The following are the contracts, other than contracts entered into the ordinary course of business of the Company, that are material to the Company and that were entered after January 1, 2002 and which are still in effect

- (1) Indemnity Agreements entered into by the Company in favour of each of the directors and officers.

These contracts have been filed on www.sedar.com.

TRANSFER AGENT

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

EXPERTS

The independent auditors of the Company are Deloitte & Touche LLP.

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 Information Circular dated March 13, 2009 for the Company's 2009 Annual Meeting of Shareholders. Additional financial information is provided in the Company's consolidated financial statements for the year ended December 31, 2008. Management's Discussion and Analysis of the Company's 2008 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 "Company")

AUDIT COMMITTEE

TERMS OF REFERENCE

A. PURPOSE

The overall purpose of the Audit Committee is to ensure that: (i) the Company'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 Company, (iii) to review the Company'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.

B. COMPOSITION, PROCEDURES AND ORGANIZATION

1. The Board of Directors of the Company (the "Board"), at its organizational meeting held in conjunction with each annual general meeting of the shareholders, shall appoint the members and the Chair 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 Company's financial statements. At least one member should have accounting or related financial expertise.
3. If the Chair is not present at any meeting of the Committee, one of the other members of the Committee present at the meeting shall be chosen by the Committee to preside at the meeting.
4. The Vice President, Finance of the Company shall be the secretary of the Committee, unless otherwise determined by the Committee.
5. The Committee shall meet at least four times annually on such dates and at such locations as may be determined by the Chair of the Committee and may also meet

at any other time or times on the call of the Chair of the Committee, the independent auditors or any two of the other members.

6. 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.
7. Any two Directors may request the Chair to call a meeting of the Committee and may attend at such meeting or inform the Committee of a specific matter of concern to such Directors, and may participate in such meeting to the extent permitted by the Chair of the Committee.
8. Notice of the time and place of every meeting shall be given in writing or by e-mail or facsimile communication to each member of the Committee at least 24 hours prior to the time fixed for such meeting; provided, however, that a member may in any manner waive a notice of a meeting and attendance of a member at a meeting is a waiver of notice of the meeting, except where a member attends a meeting for the express purpose of objecting to the transaction of any business on the grounds that the meeting is not lawfully called.
9. The Vice President, Finance shall develop and set the Committee's agenda, in consultation with the Chair and other members of management. The agenda and information concerning the business to be conducted at each Committee meeting shall, to the extent practical, be communicated to the members of the Committee sufficiently in advance of each meeting to permit meaningful review.
10. At the invitation of the Chair, one or more officers or employees of the Company may, and if required by the Committee shall, attend a meeting of the Committee. The independent auditors shall receive notice of and have the right to attend all meetings of the Committee. The Chief Executive Officer shall be invited to attend all meetings, except executive sessions and private sessions with the independent auditors.
11. The Committee shall fix its own procedure at meetings, keep records of its proceedings and report to the Board when the Committee may deem appropriate (but not later than the next meeting of the Board).
12. The Committee, when it considers it necessary or advisable, may retain, at the Company's expense, outside consultants or advisors to assist or advise the Committee independently on any matter within its mandate. The Committee shall have the sole authority to retain and terminate any such consultants or advisors or any search firm to be used to identify director candidates, including sole authority to approve the fees and other retention terms for such persons.
13. The internal auditors, if any, and the independent auditors shall have a direct line of communication to the Committee through the 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.

14. The Committee, through its Chair, may contact directly the independent auditors, the internal auditors, if any, and any employee of the Company as it deems necessary.
15. In discharging its responsibilities, the Committee shall have full access to all books, records, facilities and personnel of the Company, to the Company's legal counsel and to such other information respecting the Company as it considers necessary or advisable in order to perform its duties and responsibilities.

C. 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 Company'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 Company'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 Company's independent auditors and internal auditors (if any) and assess their performance;
- d) to ensure that the management of the Company 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 Company;

- 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 Company 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 Company including any quarterly interim reviews that may be requested by the Company, 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 Company's financial and auditing personnel;
 - iv) co-operation received from the Company's personnel during the audit;
 - v) internal resources used;
 - vi) significant transactions outside of the normal business of the Company;
 - vii) significant proposed adjustments and recommendations for improving internal accounting controls, accounting principles and management systems;
 - viii) the quality, acceptability and integrity of the Company'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 Company'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:

- iv) 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 Company to its independent auditors during the fiscal year in which the services are provided;
- v) the services were not recognized by the Company at the time of the engagement to be non-audit services; and
- vi) 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 Company's internal auditors (if in place) 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 Company are to:

- a) review the adequacy, appropriateness and effectiveness of the Company's policies and business practices which impact on the integrity, financial and otherwise, of the Company, 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 Company's Code of Business Ethics;
- c) review any issues between management and the independent auditors that could affect the financial reporting or internal controls of the Company;
- d) periodically review the Company's accounting and auditing policies, practises and procedures and the extent to which recommendations made by the internal audit staff (if any) 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 Company.

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 decisions as they relate to the Company's consolidated financial statements;

- c) ensure adequate procedures are in place for the review of the Company's disclosure of financial information extracted or derived from the Company'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 Company 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 Company 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 Company;
- h) review the appointments of the Vice President, Finance, 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 Company regarding accounting, internal controls, or auditing matters; and
 - ii) the confidential, anonymous submission by employees of the Company 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 Company;
- k) review and approve related party transactions.

6. **Pension and Savings Plans**

The Committee is charged with the responsibility to:

- a) Approve the Statements of Policies and Procedures for the Employees' Retirement Plan and other Plans as required and any amendments required thereto;
- b) 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");
- c) Receive a report from the Pension and Savings Plan Committee (the "PSPC") after each of its meetings and report to the Board thereon;
- d) 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.
- e) 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.