



Interim Report

For the Three Months Ended March 31, 2011

May 11, 2011

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Pacific Northern Gas Ltd.
MANAGEMENT'S DISCUSSION AND ANALYSIS

For the Three Months Ended March 31, 2011

Dated May 11, 2011

This management's discussion and analysis ("MD&A") should be read in conjunction with the interim consolidated financial statements of Pacific Northern Gas Ltd. ("the Company") as at and for the three months ended March 31, 2011. It should also be read in conjunction with the audited consolidated financial statements of Pacific Northern Gas Ltd. ("the Company") and related notes for the year ended December 31, 2010. The financial data included in this discussion has been prepared in accordance with Canadian generally accepted accounting principles ("Canadian GAAP"), as defined by Part V of the Canadian Institute of Chartered Accountants ("CICA") Handbook (see "Accounting Changes – Future Accounting Pronouncements"), and all dollar amounts are in Canadian dollars unless otherwise indicated.

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

Financial Highlights: First Quarter 2011 compared to First Quarter 2010

- Revenue: \$37.5 million, down 6.8% from \$40.2 million
- Net income attributable to shareholders: \$26.8 million, up 388% from \$5.5 million
- After-tax gain on sale of Company's interest in Pacific Trail Pipelines in 2011: \$21.5 million
- Earnings per share: \$7.32 up 385% from \$1.51
- Net income from continuing operations: \$6.0 million, up 4.9% from \$5.7 million
- Earnings per share from continuing operations: \$1.61, up 3% from \$1.57
- A Second Special dividend of \$3.00 per common share declared on May 11, 2011 and payable June 21, 2011
- Total gas volume delivered: 3 722 Terajoules up 9% from 3 416 Terajoules

Forward-Looking Statements

This MD&A includes forward-looking statements. Forward-looking statements relate to, among other things, (i) anticipated growth, financial performance and business prospects, (ii) business and economic conditions, (iii) strategies, (iv) regulatory developments, (v) new services, (vi) market forces and (vii) technological developments. Specifically, forward-looking statements are made with respect to expectations regarding:

- The timing and results of regulatory decisions, including with respect to the 2011 revenue requirements applications (see "Regulatory Activities");
- The timing of the potential receipt of a contingent payment relating to the sale of the Company's interest in Pacific Trail Pipelines Limited Partnership ("PTP") (see "Business Overview – Sale of the Company's Interest in PTP KSL Project);

- The timing for the commencement of transportation service for the potential LNG Partners LLC (“LNG Partners”) small scale liquefied natural gas (“LNG”) project and the cost of reactivating compressor stations to provide such service (see “Business Overview – Capacity Utilization on the Western System”);
- The benefits of the acquisition of the McNair Creek hydroelectric generation facility and the investment in Narrows Inlet Project, and the growth of opportunities in renewable energy generation (see “Business Overview - Renewable Energy Business”);
- The regulatory treatment of the West Fraser contract termination payment (see “Business Overview - Closure of West Fraser Eurocan Paper Mill”);
- The competitiveness of retail gas rates relative to electricity rates (see “Business Overview - Competitiveness of Rates”);
- The trends in customer numbers in the Western and Northeastern service areas;
- The required levels of pension funding and the fair value of pension assets;
- The renewal of franchise and operating agreements;
- The level of and source of funding for capital expenditure requirements; and
- The impact of climate change initiatives on the Company’s performance.

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 MD&A, assumptions have been made in respect of:

- gas commodity prices and, in particular, the continuation of low gas prices;
- forecasted gas deliveries as set out in the Company’s 2011 revenue requirements applications;
- regulatory conditions, including decisions by the British Columbia Utilities Commission (the “Commission”);
- the Company’s future growth opportunities;
- 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
- general economic 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 MD&A and in the Company's 2011 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; 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; the ability of the Company to attract and retain quality employees, and the impact of accounting changes, including the transition to International Financial Reporting Standards ("IFRS"). 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 MD&A 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.

Non-GAAP Measures

References to "operating margin" are to revenues less cost of gas. Operating margin is not a recognized measure under Canadian GAAP and does not have a standardized meaning prescribed by Canadian 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 the Company's gas transmission and distribution financial results are best measured by excluding the cost of gas which is flowed through to customer rates without a mark-up.

Business Overview

The Company and its wholly-owned subsidiary Pacific Northern Gas (N.E.) Ltd. ("PNG (N.E.)") are natural gas distribution utilities operating within the Province of British Columbia, Canada.

The Company operates a transmission and distribution system in the west-central portion of northern British Columbia ("Western system") and PNG (N.E.) operates a distribution system in northeastern British Columbia ("Northeast system"). The Northeast system is comprised of two divisions, the Fort St. John/Dawson Creek division and the Tumbler Ridge division.

The Company also operates and owns a 97 percent interest in the 9.8 megawatt (“MW”) McNair Creek hydro-electricity generation facility (“McNair”) located on B.C.’s Sunshine Coast. The McNair facility’s generation is committed for sale under a long-term contract to BC Hydro. The Company is also pursuing new hydro-electric generation development projects and is committed to investing up to \$2.5 million in the Narrows Inlet Project, which is also located on B.C.’s Sunshine Coast. These funds will be used to advance this project to the start of construction which is expected by mid-to-late 2012 (see “Business Overview – Renewable Energy Business”).

Business Strategy

The Company’s strategy is to increase shareholder value by optimizing the value of its existing assets and by growing and diversifying its business through targeted acquisition and development opportunities. The Company is focusing its strategic initiatives on enhancing value from its regulated business, pursuing expansion opportunities for new pipeline infrastructure to the west coast of British Columbia and evaluating development and acquisition opportunities in the renewable energy sector.

Sale of the Company's Interest in PTP KSL Project

PTP is developing the KSL Project, a proposed 463 kilometre natural gas pipeline from Summit Lake, B.C. to Kitimat, B.C. The KSL Project would serve the planned Kitimat LNG facility being developed by Apache Canada Ltd. (“Apache Canada”), EOG Resources Canada Inc. (“EOG Canada”) and EnCana Corporation (“EnCana”). On February 4, 2011, the Company entered into an agreement to sell its 50 percent interest in PTP and the underlying KSL Project to Apache Canada and EOG Canada, the Company’s partners in the project, for payments of up to \$50 million. The transaction has two cash components, the first being a payment of \$30 million that the Company received on March 2, 2011, and the second being a payment of \$20 million to be paid contingent on the purchasers making a decision to proceed with construction of the Kitimat LNG facility.

In connection with the sale of its interest in PTP, the Company agreed on the terms for 20-year transportation service agreements with each of Apache Canada and EOG Canada that will significantly increase the utilization of the Company’s current pipeline if LNG Partners does not claim this capacity first. If the LNG Partners project does not proceed and the Kitimat LNG facility does proceed, combined Apache Canada and EOG Canada would use up to 50 MMcf per day of the Company’s existing pipeline capacity to supplement KSL Project pipeline throughput. Initial deliveries would be 30 MMcf per day starting with initial LNG production and an additional 20 MMcf per day would occur if liquefaction capacity is later increased. Service under the agreements would commence with commercialization of the Kitimat LNG facility which is expected to occur in 2015. The transportation service agreements are subject to approval by the Commission.

Further, the Company negotiated with Apache Canada and EOG Canada an operating and maintenance agreement under which the Company would operate the KSL Project pipeline. This agreement will have an initial term of seven years with renewal provisions and will be subject to approval by the Commission.

Upon receipt of the first cash payment of \$30 million in March 2011, the Company recorded a net gain of \$24.2 million after transaction related costs (\$21.5 million after taxes). This reflected accounting for the \$8.3 million of KSL Project expenditures made by the Company from its inception to March 2, 2011, of which \$7.3 million was expensed and \$1.0 million was capitalized. On March 3, 2011, the Company's Board of Directors declared a special dividend of \$3.00 per common share, which represented approximately \$11 million of the proceeds from the sale of PTP. On May 11, 2011, the Company's Board of Directors declared an additional special dividend of \$3.00 per common share, which represents an additional \$11 million of the remaining proceeds.

Should the second contingent payment of \$20 million be made, the total \$50 million sale proceeds would have an approximate value to shareholders of \$9 to \$10 per share after taxes and related expenses, including payments under the KSL Project management incentive plan. The disposition of PTP has resulted in its presentation as discontinued operations in the Company's financial statements in both 2011 and 2010.

The Company can give no assurances that construction of the Kitimat LNG facility will be completed or that the second \$20 million contingent payment will be made.

Potential to Increase Utilization on the Western System

PNG believes there is potential to significantly increase utilization on its western system beyond the volumes proposed for the Kitimat LNG project based on the expectation there is room for, and there may be demand for, more than one LNG project in the Company's service area.

PNG's assessment is based in part on the continuing price spread between natural gas in North America, the supply source; and Asia, the intended market. In North America, natural gas prices have been declining mainly because of technological advances used for the discovery of shale gas and other unconventional sources. This includes significant and growing reserves in Northeast British Columbia. At the same time, natural gas prices have increased in Asia due in part to the growth of Asian economies, especially China.

While there can be no assurance that the favourable trend will continue, or that any LNG projects will actually be developed, PNG is aware of recent progress made with regard to the LNG Partners small scale LNG export project. The Company and LNG Partners are parties to a Commission approved transportation service agreement (TSA) that provides a capacity option of 80 MMcf per day. The TSA documents the option provisions and the transportation service provisions that would apply following exercise of the option. If LNG Partners exercises its option, it would utilize the transportation service to deliver natural gas to an LNG facility to be located on the Douglas Channel near Kitimat, B.C. LNG Partners expects that the LNG produced at this facility would be exported to LNG markets in Asia. During the first quarter of 2011, BC LNG Export Co-operative LLC an

affiliate of LNG Partners, applied to the National Energy Board (NEB) for permission to export LNG. According to the application, BC LNG Export Co-operative is a 50:50 partnership between LNG Partners and the Haisla Nation Douglas Channel LNG Limited Partnership.

The Company has received option fees of \$4.5 million to secure the exclusive option under the TSA until June 30, 2011 to contract for firm gas transportation capacity for a two- to five-year primary term, with a right to renew for three additional five-year terms. LNG Partners may extend the option period by up to two further six-month periods, with payment of \$1 million for each extension.

If service commences under the TSA, the Company's Western system would be at full capacity utilization, generating approximately \$16 million per year of incremental margin for the benefit of the Company and its customers. The cost to reactivate the facilities left idle when Methanex Corporation ("Methanex") ceased operations in 2005 will be recovered from these incremental revenues. The reactivation costs are in the range of \$1.3 million with the largest single expense being the cost of completing a compressor overhaul at an estimated cost of \$0.5 million. For regulatory purposes, the Company anticipates expensing all reactivation costs in the first year of operation. If service commences by June 30, 2012 all of the option fees previously paid to the Company will be credited to transportation service fees payable in 2012. The option fee credit to LNG Partners will be reduced by \$0.5 million if service commences after June 30, 2012 but before December 31, 2012. A further reduction of \$0.5 million will apply if service commences after December 31, 2012. If service does not commence by January 1, 2015 then the TSA would terminate and the Company would retain all option fees.

The Company can give no assurances that LNG Partners will continue to extend the option or exercise its option to take capacity on the Western system.

Renewable Energy Business

The Company continues to advance its renewable energy strategy with an investment in the 45 MW Narrows Inlet run-of-river renewable energy project ("NI Project"), also referred to as the Stl'ixwim Renewable Energy Initiative or the Stl'ixwim Project. The Company has formed Narrows Inlet Limited Partnership ("NILP") with Skookum Power Corp. to undertake an investment of up to \$2.5 million to advance the NI Project to the start of construction. To March 31, 2011, the Company has invested \$0.3 million. Prior to the commencement of construction, the Company will make its final investment decision, and through NILP, will have an exclusive option to provide construction equity as well as an option to ensure NILP owns a 50 percent interest in the NI Project.

Partnering with Skookum Power Corp., as it did on the McNair Creek facility, allows the Company to gain access to hydro development and construction expertise. Both parties will be working closely with the team of existing NI Project developers, Renewable Power Corp. and Altaqua Renewable Power Corp., to advance the project through the B.C. Environmental Assessment process. Renewable Power Corp. has extensive experience in hydro project development, construction and operations and was the founding partner of the McNair Creek facility.

The NI Project was awarded a 30 year energy purchase agreement with B.C. Hydro in spring of 2010. Construction is expected to commence in mid/late 2012, with an estimated capital cost of approximately \$190 million of which approximately \$20 million would be equity provided by the Company if NILP elects to proceed with funding construction. The NI Project consists of five developments on four creeks that are located within a radius of 5 to 7 km of each other at the northern end of Narrows Inlet which is located approximately 35 km north of the town of Sechelt, British Columbia and lies within the Sechelt Nation's traditional territory. The NI Project is expected to benefit from coastal precipitation patterns, some storage capacity and close proximity to the largest electricity load center in British Columbia.

Conditions to construction include the receipt of the necessary environmental and construction permits required to commence construction, securing of contractor agreements to construct the facility, and financing for construction of the NI Project. The Company can give no assurances that these conditions will be satisfied or that construction of the NI Project by NILP will proceed.

Closure of West Fraser Eurocan Paper Mill

West Fraser Timber Co. Ltd. ("West Fraser") permanently closed its Kitimat B.C. linerboard mill at the end of January 2010 and terminated its contract with the Company effective November 30, 2010. On December 1, 2010 the Company received from West Fraser a contract termination payment of \$5.1 million. The termination payment will be amortized into earnings over the remaining life of the agreement provided the Commission approves the 2011 revenue requirements application settlement agreement. Such approval is expected by the end of May 2011. In addition, as was the case with the closure of the Methanex plant, the Company will mitigate the impact of lower margin recovery by managing its costs and by seeking Commission approval to recover the future loss of margin through standard rate applications to the Commission. Should these measures be approved, the Company anticipates limited impact on future earnings.

Competitiveness of Rates

As a distributor of natural gas, the Company monitors the competitiveness of its natural gas retail rates relative to alternative heating sources in its service areas. The Company's current residential rates in all divisions are lower than the current comparable residential electricity rate. Declines in gas commodity prices payable by the Company during 2010 and in 2011 have helped to make gas rates more competitive relative to electricity.

The Province of British Columbia's (the "Province") 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 have contributed to and are expected to result in higher electricity rates over the long term. The Province implemented a carbon tax on fossil fuel consumption effective July 1, 2008. The carbon tax on natural gas was just under \$0.50 per gigajoule ("GJ") effective July 1, 2008, rising annually by 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, the cessation of

the Methanex termination payment credit amortization and the closure of the West Fraser Eurocan Kitimat paper mill in January 2010, the Company expects its retail gas rates will maintain their relative competitiveness with electricity rates as electricity rates are expected to rise over time to meet the Province's energy policy objectives. The Company's 2011 Western system revenue requirements application settlement provides for a bundled average residential rate of \$19.37 per GJ effective January 1, 2011, including the current carbon tax of \$0.9932 per GJ. This is approximately 10 percent less than the comparable residential conservation electricity rate of \$21.44 per GJ. The competitiveness of gas to electricity was improved with a reduction in the gas supply cost recovery component of rates of \$0.72 per GJ effective April 1, 2011.

Overall Performance

The disposition of the Company's interest in PTP has been presented as discontinued operations in accordance with Canadian accounting standards and the Company has restated its prior year's figures to conform with this presentation.

Net income for the three months ending March 31, 2011 was \$26.8 million, compared with \$5.5 million for the corresponding period in 2010. After providing for preferred share dividends, basic earnings per common share for the three months ended March 2011 were \$7.32 compared with \$1.51 for the same period in 2010. The increase was mainly due to the gain on sale of the Company's interest in PTP. Net income from discontinued operations was \$20.8 million in the first quarter of 2011 composed of the net after tax gain of \$21.5 million recognized on the sale of the KSL project and \$0.7 million of the Company's share of KSL project development expenses incurred prior to its sale compared to a net loss of \$0.2 million in the first quarter of 2010.

Net income from continuing operations for the three months ending March 31, 2011 was \$6.0 million compared to \$5.7 million for the comparable period in 2010. The increase in earnings from continuing operations is mainly due to higher than anticipated small industrial volumes in the first quarter of 2011, incremental rate base in 2011 and the inclusion of McNair operations in the first quarter of 2011. The allowed weighted average ROE remains at 10.09 percent for 2011, the same as in 2010.

The rate stabilization adjustment mechanism approved by the Commission continues to contribute to the stability of the Company's earnings. This mechanism allows the Company to record the after-tax revenue variances arising from differences between actual and forecast sales volumes for residential and small commercial customers in a deferral account for collection or refund in future rates. As a result of the colder weather experienced this period, the Company recorded in this deferral account, to be refunded to customers in future rates an after-tax revenue variance of \$1.3 million for the three month period ended March 31, 2011.

Natural Gas Volumes

The table below sets forth natural gas volumes delivered by PNG for the first quarter of 2011, compared with a year earlier.

[Deliveries in TJ]

	First Quarter 2011	First Quarter 2010	% Change
Sales:			
Residential	1 349	1 146	+18%
Commercial	1 094	937	+17%
Small Industrial	153	134	+14%
Large Industrial	-	-	-
Total Sales	2 596	2 217	+17%
Transportation Service:			
Commercial	139	89	+56%
Small Industrial	723	631	+15%
Large Industrial	264	479	(45%)
Total Transportation Service	1 126	1 199	(6%)
Total Deliveries	3 722	3 416	+9%

Residential deliveries were approximately 18 percent higher in the three months ended March 31, 2011 and total commercial deliveries were 20 percent higher, relative to deliveries over the same period in 2010. Management believes that weather was the key reason for higher deliveries as it was approximately 18 percent colder for the three month period ended March 31, 2011 compared to the same period in 2010. The weather was also 9 percent colder than normal for the three month period ended March 31, 2011, with “normal” based on the average of actual temperatures in the Company’s service areas for the preceding 10 years.

Industrial deliveries were lower by approximately 8 percent for the three month period ended March 31, 2011 compared to the same period in 2010. The decrease in industrial deliveries is comprised of a 45 percent decrease in large industrial customer deliveries, mainly due to the closure of the West Fraser Kitimat liner board mill, combined with a 15 percent increase in deliveries to small industrial customers. The small industrial customer deliveries were higher primarily in the Western system due to significant gas demand for coal drying at Ridley Island Terminals reflecting the impact of colder weather and higher than normal coal shipments. Deferral accounts are in place that recover or refund margin differences resulting from deliveries to large industrial customers and to some small industrial customers varying from the forecast approved for rate making purposes.

Results of Operations

The following table summarizes the Company's revenues and operating results for continuing operations, by business segment. A discussion of discontinued operations can be found under "Business Overview – Sale of the Company's Interest in PTP KSL Project".

[\$ in thousands]

Continuing Operations	Gas Transmission and Distribution	Renewable Energy	Total
Three months ended March 31, 2011			
Revenues	\$37,038	\$441	\$37,479
Operating margin	17,966	441	18,407
Net income from continuing operations	5,932	38	5,970
Three months ended March 31, 2010			
Revenues	\$40,235	\$ -	\$40,235
Operating margin	17,897	-	17,897
Net income from continuing operations	5,687	-	5,687

Gas Transmission and Distribution

Revenues in the three months ended March 31, 2011 were \$37.0 million compared with \$40.2 million in the same period in 2010. The \$3.2 million decrease reflected a reduction of \$4.6 million in the sale of gas surplus to customer requirements ("off system gas sales"), lower commodity costs in 2011 compared to 2010, and a partial offset from higher sales volumes due to colder weather. Any profit or loss realized on off system gas sales is deferred for future recovery from, or refund to, the Company's sales customers. The decrease in off system gas sales in the first quarter of 2011 reflects the impact of higher deliveries to on system customers due to colder temperatures. Natural gas commodity prices, which are passed through to the Company's sales customers without mark-up, can be volatile, creating significant variability in the Company's reported revenues and cost of gas.

Operating margin in the three months ended March 31, 2011 increased slightly to \$18.0 million, as compared with \$17.9 million in the same period in 2010. The increase of \$0.1 million was mainly due to higher than anticipated deliveries to small industrial customers and higher than anticipated net customer additions in 2011, partially offset by lower than anticipated deliveries to large commercial customers.

Renewable Energy

For the three months ended March 31, 2011, the McNair hydro-electric facility generated revenues of \$0.44 million. Operating costs for this period amounted to \$0.1 million. The Company recorded net after-tax earnings of approximately \$0.04 million from renewable energy operations. There are no first quarter 2010 comparative results since the McNair Creek facility was not acquired until April 19, 2010.

As described in the “Summary of Quarterly Results”, production from the McNair facility is seasonal. During the first three months of 2011, the McNair Creek facility experienced average hydrologic conditions. As a result, electricity generation from the McNair Creek facility for the three months ended March 31, 2011 was consistent with the long-term average that was estimated using standard industry procedures.

2011 Revenue Requirements Applications

Negotiated settlements of the Company’s 2011 revenue requirements applications were reached on April 27, 2011 between the Company and customer representatives in respect of all divisions. The Commission is currently reviewing the settlements and the Company expects Commission approval by the end of May 2011.

The Western system settlement results in the applied for \$2.1 million revenue deficiency for 2011 declining to approximately \$0.5 million. Of this reduction, \$0.3 million reflects agreed to amendments to budgeted expenses, \$0.2 million is for an overall settlement allowance and \$0.5 million pertains to the sale of PTP. The majority of the balance of the reduction is due to increasing the forecast of deliveries to residential and small commercial customers (\$0.4 million) used for rate making purposes.

Under the Western system settlement the gas delivery rate increase for residential customers, effective January 1, 2011, compared to the corresponding delivery rate as of October 1, 2010, is approximately \$0.17 per GJ. This represents an annual bill increase of \$11 or 0.9 percent for the average residential customer consuming 66.7 GJ/year. The gas supply commodity rate decrease as of April 1, 2011 results in the annual gas bill for a typical residential customer being 2.9 percent lower compared to the annual bill using October 1, 2010 rates.

The Pacific Northern Gas (N.E.) Ltd. (“PNG (N.E.)”) Fort St. John/Dawson Creek division’s settlement results in the \$2.6 million revenue deficiency decreasing by \$0.4 million to \$2.2 million. The gas delivery rate increase for residential customers, effective January 1, 2011, compared to the corresponding delivery rate as of October 1, 2010, is \$0.74 per GJ. This represents an annual bill increase of \$79 or 8 percent for the average residential customer consuming 108 GJ/year. The gas supply commodity rate decrease as of April 1, 2011 results in the annual gas bill for a typical residential customer being virtually equal to the annual bill using October 1, 2010 rates. The PNG (N.E.) Tumbler Ridge division settlement results in the applied for \$0.05 million revenue deficiency decreasing by \$0.08 million to result in a modest revenue sufficiency of \$0.03 million.

Summary of Quarterly Results

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

[\$ in thousands, except for per share data]

<i>(unaudited)</i>	June 30, 2010	Sept. 30, 2010	Dec. 31, 2010	Mar. 31, 2011
Continuing Operations				
Revenues	\$15,166	\$9,682	\$30,081	\$37,479
Net income (loss)	\$33	\$(2,227)	\$3,992	\$5,970
Earnings (loss) per common share – basic	\$(0.01)	\$(0.64)	\$1.10	\$1.61
Earnings (loss) per common share – diluted	\$(0.01)	\$(0.64)	\$1.06	\$1.57
Discontinued Operations				
Net income (loss)	\$(181)	\$(20)	\$(7)	\$20,823
Earnings (loss) per common share – basic	\$(0.05)	\$(0.00)	\$(0.00)	\$5.71
Earnings (loss) per common share – diluted	\$(0.05)	\$(0.00)	\$(0.00)	\$5.54

	June 30, 2009	Sept. 30, 2009	Dec. 31, 2009	Mar. 31, 2010
Continuing Operations				
Revenues	\$14,141	\$10,500	\$31,172	\$40,235
Net income (loss)	\$(373)	\$(1,645)	\$3,476	\$5,687
Earnings (loss) per common share – basic	\$(0.12)	\$(0.49)	\$0.96	\$1.57
Earnings (loss) per common share – diluted	\$(0.12)	\$(0.49)	\$0.94	\$1.53
Discontinued Operations				
Net loss	\$(27)	\$(15)	\$(40)	\$(199)
Net loss per common share – basic	\$(0.01)	\$(0.00)	\$(0.01)	\$(0.06)
Net loss per common share – diluted	\$(0.01)	\$(0.00)	\$(0.01)	\$(0.06)

The Company's natural gas distribution business is very seasonal, with higher sales in the colder winter months and lower sales in warmer months. Deliveries to residential and commercial customers tend to be more temperature sensitive than deliveries to industrial customers, with deliveries in the first and fourth quarters accounting for more than 75% of annual deliveries. Given that a substantial portion of its gas sales are used for space heating purposes, the Company earns in excess of its annual net income in the first and fourth quarters of its fiscal year and generally realizes losses in the other two quarters.

The Company's renewable energy business is also seasonal, with revenues from electricity sales highly correlated to the amount of precipitation, as well as the timing of snow pack melt in the catchment area of the McNair Creek hydroelectric power plant. The Company expects that almost 40 percent of its annual production will occur in the

second quarter, only 10 percent will occur in the third quarter, with the first and fourth quarters providing the remainder of the production relatively equally.

Liquidity

At March 31, 2011, the Company has credit facilities which include a \$25 million operating line, two risk management facilities each secured by the pledge of a \$20 million debenture issued by the Company and a \$35 million committed 5-year term revolving debt facility.

Borrowings under the operating facility bear interest at prime rate or bankers' acceptance rates plus an applicable credit spread. The facility has a term of 18 months, expiring May 28, 2012. The Company may also issue letters of credit under the operating facility. As of March 31, 2011, the actual utilization of the operating line was \$3.8 million.

The risk management facilities are utilized by the Company to hedge natural gas purchases in accordance with its annual gas contracting and gas supply price risk management plan and to enter into interest rate hedging transactions.

\$16.0 million was outstanding under the revolving term facility at March 31, 2011 under Bankers Acceptance equivalent loans. Additional funds available under the facility will be used for general corporate purposes including the Company's capital program and debt repayments.

Cash and cash equivalents at March 31, 2011 of \$18.1 million were \$16.8 million higher than at December 31, 2010, mainly due to the net proceeds received from the sale of the Company's interest in PTP. Accounts receivable at March 31, 2011 of \$23.0 million remained the same balance from December 31, 2010, mainly due to higher customer receivables due to higher volumes offset by lower off system sales receivables. Prepaid expenses of \$0.8 million at March 31, 2011 are slightly lower due to expensing of insurance costs.

Accounts payable and accrued liabilities of \$16.2 million at March 31, 2011 were lower by \$2.8 million compared to December 31, 2010, mainly due to lower gas purchase costs in March 2011 as a result of lower gas commodity prices. At March 31, 2011, there is a \$3.4 million income tax payable balance compared to an income tax recoverable amount of \$1.3 million at December 31, 2010. This is mainly due to the accrual for taxes to be paid on the sale of the Company's interest in PTP.

The gas purchase variance recoverable account has decreased by \$2.6 million resulting in a net recoverable amount of \$1.9 million at March 31, 2011, compared to the net recoverable balance of \$4.5 million at December 31, 2010. This decrease was mainly due to the following three items: the net liability fair value of the Company's derivative financial instruments recorded in the gas purchase variance account decreased to a net liability position of \$3.4 million at March 31, 2011, down \$2.7 million from \$6.1 million at December 31, 2010; the gas purchase variance account increased by \$0.6 million as the Company refunded amounts to customers via rate rider credits; and gas commodity costs

paid by the Company in 2010 were less than the gas commodity cost rates paid by customers resulting in a decrease in the gas purchase variance account by \$0.5 million.

Capital Resources

Planned capital spending in 2011 is primarily directed toward installation of distribution mains and services in the Northeast system as well as transmission mainline rehabilitation in the Western system, and is forecast to be approximately \$7.4 million, of which \$0.8 million has been spent to date. Contractual commitments of approximately \$1 million have been made for major planned capital expenditures for 2011. These capital expenditures will be funded from cash flow from operations and, if required, draws on the Company's debt facilities.

The Company has also undertaken to spend up to \$2.5 million in the Stl'ixwim Project during 2011 and part of 2012. See "Business Overview – Renewable Energy Business".

Dividends

The Board of Directors declared a semi-annual dividend of 84.375 cents per share on the Company's 6-3/4 percent cumulative, redeemable, preferred shares, payable July 1, 2011 to the shareholders of record at the close of business on June 16, 2011.

The Board of Directors also declared a special dividend of \$3.00 per share and a regular quarterly dividend of 30 cents per share on the Company's common shares. The total dividend of \$3.30 is payable June 21, 2011 to shareholders of record at the close of business on June 6, 2011.

Pacific Northern Gas Ltd., for purposes of the Income Tax Act (Canada), and any similar provincial or territorial legislation, designates all dividends paid by Pacific Northern Gas Ltd. after December 31, 2005 to be "eligible dividends" unless otherwise notified by the Company. An eligible dividend paid to a Canadian resident is entitled to the enhanced dividend tax credit.

Business Risk Management

A detailed discussion of the Company's significant business risks is provided in the MD&A for the year ended December 31, 2010 and in the Company's 2011 Annual Information Form, both of which can be found at www.sedar.com. There were no changes to the Company's significant business risks during the three months ended March 31, 2011.

Off-Balance Sheet Arrangements

As of March 31, 2011, the Company had no off-balance sheet arrangements.

Transactions with Related Parties

The Company had no significant transactions with related parties during the three month period ended March 31, 2011.

Critical Accounting Estimates

The preparation of the Company's consolidated financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and the related disclosures. These estimates are based on historical experience, current assumptions, and actual results may differ from these estimates under different assumptions and conditions.

Effective January 1, 2011, as described under "Accounting Changes – Changes Applied in 2011 – 2011 Revenue Requirement Application Changes" below, the Company made changes to accounting estimates related to the remaining useful lives of its plant and equipment assets and to the cost pools and capitalization rates for overhead costs capitalized to self-constructed plant and equipment. Other than these noted changes, there were no material changes in the nature of the Company's critical accounting estimates during the three months ended March 31, 2011 from those disclosed in the Company's MD&A for the year ended December 31, 2010.

Operating revenues include natural gas sales that are recorded on the basis of regular meter readings and estimates of customer usage from the last meter reading date to the end of the reporting period for such operating revenues. These estimates are made assuming normal consumption patterns, adjusted for weather variations, which may differ from actual consumption patterns. The estimates of unbilled operating revenue at March 31, 2011 comprise 20.6 percent of the Company's operating revenues for the three month period ended March 31, 2011. Through future meter readings, the usage estimates are replaced with actual delivered volumes which will be reflected in the Company's financial results at that time.

Accounting Changes

Changes Applied in 2011

2011 REVENUE REQUIREMENT APPLICATION CHANGES

Effective January 1, 2011, the Company adopted the following new accounting policies and changes in accounting estimates on a prospective basis in accordance with its 2011 revenue requirement applications filed with the Commission. These changes in depreciation, capitalization of overheads and accounting for non-pension post-retirement benefits were accepted under negotiated settlements reached on April 27, 2011. The Commission is expected to approve the settlements by the end of May 2011.

Depreciation of plant and equipment is recorded on a straight-line basis over the underlying assets' useful lives. Effective January 1, 2011, the Company implemented the

recommendations of a recently completed depreciation study which resulted in adjustments to the estimated remaining useful lives of plant and equipment assets. For 2011, these changes are expected to result in a net decrease in depreciation expense of approximately \$2 million.

Other changes as reflected in the Company's 2011 revenue requirements applications include a reduction in the pool of overhead costs subject to capitalization as part of the cost of plant and equipment and the inclusion of the full actuarially-determined expense for non-pension post-employment benefit plans. All of these changes were adopted on a prospective basis and are not expected to impact net earnings due to their inclusion in the 2011 revenue requirements applications.

CANADIAN ACCOUNTING STANDARD CHANGES

Comprehensive Revaluation of Assets and Liabilities

In August 2009, the CICA amended Handbook Section 1625, Comprehensive Revaluation of Assets and Liabilities, as a result of issuing Sections 1582, Business Combinations, 1601, Consolidated Financial Statements, and 1602, Non-Controlling Interests, in January 2009. The amendments require that when push-down accounting is used following the acquisition of an enterprise, the assets and liabilities are to be measured at the values used in accounting for the purchase transaction or transactions in accordance with Section 1582. The amendments also require that, when a future income tax asset that arose prior to the date of a comprehensive revaluation and that was not recognized in the comprehensive revaluation is subsequently recognized, the benefit should be recognized in accordance with Section 1582 and Section 3465, Income Taxes. The amendments apply prospectively to comprehensive revaluations of assets and liabilities occurring in fiscal years beginning on or after January 1, 2011. The adoption of the amendments to Section 1625 had no effect on the Company's consolidated financial statements.

Financial Instruments – Recognition and Measurement

In June 2009, the CICA provided a clarification to Handbook Section 3855, Financial Instruments – Recognition and Measurement, with respect to the embedded prepayment option. The Section has been amended to clarify when an embedded prepayment option is separated from its host instrument for accounting purposes. The amendment states that if the exercise price of a prepayment option compensates the lender for an amount equivalent to the present value of the lost interest for the remaining term of the host instrument, the feature is considered closely related to the host contract in which it is embedded. The amendment applies to interim and annual financial statements relating to fiscal years beginning on or after January 1, 2011. The adoption of the amendments to Section 3855 had no effect on the Company's consolidated financial statements.

Multiple Deliverable Revenue Arrangements

In December 2009, the CICA issued EIC-175, Multiple Deliverable Revenue Arrangements, replacing EIC-142, Revenue Arrangements with Multiple Deliverables. The changes were made in response to changes made to Accounting Standards Codification Topic 605-25, Revenue Recognition – Multiple Element Arrangements, under US GAAP, and more closely aligns the accounting requirements for multiple-element arrangements under Canadian GAAP and IFRS. EIC-175 addresses how to determine whether an arrangement involving multiple deliverables contains more than one accounting unit and, if so, how the consideration specified in the multiple element arrangement should be distributed between different accounting units. These recommendations are to be applied prospectively to revenue arrangements with multiple deliverables entered into or materially modified in the first annual fiscal period beginning on or after January 1, 2011. The adoption of EIC-175 had no effect on the Company's consolidated financial statements.

Future Accounting Pronouncements

TRANSITION TO INTERNATIONAL FINANCIAL REPORTING STANDARDS

The Canadian Accounting Standards Board (“AcSB”) has determined that publicly accountable enterprises are required to prepare financial statements in accordance with IFRS for years beginning on or after January 1, 2011. However, in October 2010, the AcSB issued an amendment to Part I of the CICA Handbook allowing for a one-year deferral for first-time adoption of IFRS for qualifying entities with rate-regulated activities. The Canadian Securities Administrators' regulations have also been amended to incorporate the AcSB's one-year deferral.

As previously disclosed, the Company meets the requirements of a qualifying entity and has elected to take the optional one-year deferral as allowed by the AcSB. The Company's revised IFRS conversion date is January 1, 2012.

IFRS Project

The Company's IFRS project plan has been amended to accommodate the decision to defer adoption of IFRS for one year. The Company is satisfied that its transition plans are on schedule and will continue to provide updates on the status of key activities in future 2011 interim Management's Discussion and Analysis.

In addition to planning for the adoption of IFRS, the Company continues to monitor changes to standards that may become effective during or shortly after the implementation phase. The Company will continue to follow the proposals contained in International Accounting Standards Board exposure drafts and to assess potential impacts of new IFRS that may be applicable as at the January 1, 2012 conversion date.

During the first quarter of 2011, the Company determined the estimated impact of significant IFRS opening balance sheet adjustments, as follows:

IFRS 1, First-Time Adoption of International Financial Reporting Standards

As previously disclosed, the Company will be making use of the following elections available under IFRS 1:

(i) Employee Benefits

IFRS 1 permits a first-time adopter to recognize all cumulative actuarial gains and losses and unamortized transitional obligations as determined under the Company's previous GAAP in retained earnings at the date of transition to IFRS. As previously disclosed, the Company will use this exemption. The estimated impact as at January 1, 2011, is an \$11.3 million increase in the net liability for defined-benefit post-employment plans, a decrease to the future income tax liability of \$2.8 million and a resulting reduction to retained earnings of \$8.5 million.

(ii) Property, Plant and Equipment and Intangible Assets

IFRS 1 permits a first-time adopter to use the carrying amount of rate-regulated property, plant and equipment and intangible assets, as calculated under Canadian GAAP, as the deemed cost for IFRS on the date of transition.

The Company will elect to use this exemption for the significant majority of its property, plant and equipment and intangible assets used in rate-regulated operations. As at January 1, 2011, this will result in an estimated decrease of \$141.1 million in the cost of these assets and an offsetting decrease in accumulated depreciation previously recorded on these assets.

Other Adjustments

(i) Property, Plant and Equipment

For select property, plant and equipment asset classes, the Company will apply IAS 16, *Property, Plant and Equipment*, on a retrospective basis. The estimated impact as at January 1, 2011, is a \$0.8 million decrease in the carrying value of property, plant and equipment, with a \$0.2 million decrease in the future income tax liability and a resulting \$0.6 million reduction in retained earnings.

The Company has deactivated facilities resulting from the closure of the Methanex methanol plant in January 2006. These deactivated facilities represent tangible assets that the Company anticipates to be put in future service in the event of additional capacity resulting from development activities currently underway. The Company currently records these deactivated facilities as regulatory assets. As at January 1, 2011, the \$2.8 million carrying value of these deactivated facilities will be reclassified from regulated assets to property, plant and equipment.

(ii) Deferred Revenue

To December 31, 2010, the Company received \$4.5 million in option and extension fees to secure excess firm pipeline capacity. This \$4.5 million is non-refundable

except in the event that the option is exercised and these payments will be applied against future transportation charges. Accordingly, under IFRS, these payments are recorded as deferred revenue until the option lapses or transportation services commence. For regulatory purposes, \$2.0 million of the option fees have been applied to reduce customer rates. As at January 1, 2011, the \$2.0 million applied to customer rates will be re-established as deferred revenue and this will result in a \$2.0 million increase in other liabilities, a \$0.6 million decrease in future income tax liabilities and a resulting \$1.4 million reduction in retained earnings.

(iii) Regulatory Assets and Liabilities

The Company uses regulatory deferral accounts in its rate-setting process and these deferral accounts are realized through increases or decreases in future customer rates. Canadian GAAP has allowed balance sheet recognition of these regulatory deferral accounts and they are recorded as regulatory assets and liabilities.

Under current IFRS, there is no separate standard for rate-regulated activities. In addition, regulatory assets and liabilities that are realized through future customer rates, do not meet balance sheet recognition criteria under existing IFRS guidance.

As at January 1, 2011, the Company has determined the estimated impact of derecognizing these regulatory assets and liabilities to be as follows:

- \$3.8 million decrease in gas purchase variance recoverable;
- \$11.8 million decrease in regulatory assets;
- \$5.0 million decrease in regulatory liabilities;
- \$2.3 million decrease in future income tax liability; and
- \$8.3 million decrease in retained earnings.

Financial Instruments and Other Instruments

The Company utilizes natural gas commodity hedging contracts in order to manage the volatility inherent in the prices of its natural gas purchases. It may also utilize interest rate hedging contracts to reduce the volatility of the interest expense associated with its floating rate debt instruments. As of March 31, 2011, the Company had no interest rate hedging contracts outstanding.

During the second quarter of 2010, the Company completed its annual gas contracting and gas price risk management plan and filed it with the Commission for review and acceptance. The annual gas contracting plan covered proposed gas purchases over the November 1, 2010 to October 31, 2011 period, while the gas price risk management plan provided for hedging gas purchases over the November 1, 2010 through October 31, 2012 period. The Company proposed implementing the hedges in stages over the May 2010 to February 2012 period. The Commission accepted the plan as filed. Each hedging transaction is approved by the Company's price risk management plan committee and is reported to the Commission on a monthly basis.

At March 31, 2011, the Company had outstanding natural gas swap and collar contracts relating to natural gas supply as follows:

Financial instrument	Notional quantity (gigajoules)	Percent of annual gas purchases (%)	Delivery period	Price range (per gigajoule)	Estimated net fair value payable (\$000's)
Natural gas swap contracts	3 175 500	34.1	Apr 2011 – Oct 2012	\$3.94 - \$6.49	(3,399)
Collar contracts	53 500	0.6	Apr 2012 – Oct 2012	\$3.80 (floor) - \$5.81 (cap)	(12)
	3 229 000	34.7			(3,411)

The fair value reflects the estimated amounts that the Company would receive or pay at March 31, 2011 to terminate the fixed-price, natural gas swap and collar contracts based on the estimated net cash flows under the terms of each contract.

These estimated fair market values have no impact on earnings due to the regulated nature of the Company's operations. Based on the current regulatory process, any gains or losses arising from utility related financial gas hedging instruments would be treated as part of the flow through of gas supply costs in customer rates.

At December 31, 2010, the Company had outstanding fixed-price, natural gas swap and collar contracts relating to natural gas supply as follows:

Financial instrument	Notional quantity (gigajoules)	Percent of annual gas purchases (%)	Delivery period	Price range (per gigajoule)	Estimated net fair value payable (\$000's)
Fixed-price contracts	900 000	9.4	Jan 2011 – Mar 2011	\$4.23	(678)
Natural gas swap contracts	3 846 600	40.2	Jan 2011 – Oct 2012	\$4.16 - \$7.26	(5,453)
Collar contracts	53 500	0.6	Apr 2012 – Oct 2012	\$3.80 (floor) - \$5.81 (cap)	(8)
	4 800 100	50.2			(6,139)

The fair value reflects the estimated amounts that the Company would receive or pay at December 31, 2010 to terminate the fixed-price, natural gas swap and collar contracts based on the estimated net cash flows under the terms of each contract.

Certification of Disclosure Controls and Procedures and Internal Control over Financial Reporting

The Company's management is responsible for establishing and maintaining disclosure controls and procedures ("DC&P") and internal controls over financial reporting ("ICFR"), as those terms are defined in National Instrument 52-109, *Certification of Disclosure in Issuers' Annual and Interim Filings*. The objective of this instrument is to improve the quality, reliability and transparency of information that is filed or submitted under securities legislation.

Management, with the participation of the Chief Executive Officer and Vice President, Finance, acting as the Chief Financial Officer, have designed DC&P and ICFR to provide reasonable assurance that material information is reported to them on a timely basis; that financial reporting is reliable; and that financial statements prepared for external reporting purposes are in accordance with Canadian GAAP.

There have been no changes in the Company's ICFR that occurred during the period beginning January 1, 2011, and ended on March 31, 2011 that has materially affected, or is reasonably likely to materially affect, the Company's ICFR.

Outstanding Share Data

At May 11, 2011, there were 200,000 preferred shares and 3,737,004 common shares outstanding. The common shares are the only issued voting securities of the Company, and there are no securities outstanding which may be converted into voting or equity securities.

As at May 11, 2011, there were 224,000 stock options granted and outstanding (representing 6 percent of issued and outstanding common shares). Each option is exercisable for one common share.

Pacific Northern Gas Ltd.
CONSOLIDATED STATEMENTS OF INCOME AND
COMPREHENSIVE INCOME

Three months ended March 31

[\$ in thousands, except per share data]	2011	2010
Revenues:		
Gas sales and transportation services	30,100	29,051
Off system sales	6,432	11,063
Electricity sales	441	—
Other	506	121
	37,479	40,235
Cost of gas:		
Gas sales	12,640	11,275
Off system sales	6,432	11,063
	19,072	22,338
	18,407	17,897
Operating and maintenance	3,270	3,031
Administrative and general	2,608	2,299
Depreciation and amortization [note 4]	1,455	2,100
Municipal and other taxes	1,237	1,173
	8,570	8,603
	9,837	9,294
Finance fees	1,843	1,449
Income from continuing operations before income tax expense	7,994	7,845
Income tax expense [note 6]	2,024	2,158
Net income from continuing operations	5,970	5,687
Net income (loss) from discontinued operations [note 5]	20,823	(199)
Net income and comprehensive income	26,793	5,488
Net income and comprehensive income attributable to non-controlling interest	(2)	—
Net income and comprehensive income attributable to shareholders	26,791	5,488
Basic earnings (loss) per common share: [note 7]		
From continuing operations	1.61	1.57
From discontinued operations	5.71	(0.06)
	7.32	1.51
Diluted earnings (loss) per common share: [note 7]		
From continuing operations	1.57	1.53
From discontinued operations	5.54	(0.05)
	7.11	1.48

The accompanying notes to the interim consolidated financial statements are an integral part of these financial statements.

Pacific Northern Gas Ltd.
CONSOLIDATED BALANCE SHEETS
(Unaudited)

[\$ in thousands]	March 31 2011	December 31 2010
ASSETS		
Current assets:		
Cash and cash equivalents <i>[note 15]</i>	18,073	1,301
Accounts receivable <i>[note 11]</i>	23,021	23,016
Gas purchase variance recoverable	1,850	4,498
Income taxes recoverable	—	1,305
Inventories of natural gas and supplies	937	764
Prepaid expenses	796	1,056
Future income taxes	967	1,105
Current assets of discontinued operations <i>[note 5]</i>	—	594
	45,644	33,639
Plant, property and equipment	197,030	196,176
Intangible assets	1,776	1,766
Regulatory and other assets	13,958	17,659
Long-term assets of discontinued operations <i>[note 5]</i>	—	684
	258,408	249,924
LIABILITIES		
Current liabilities:		
Bank indebtedness	—	4,836
Accounts payable and accrued liabilities	16,154	18,909
Income taxes payable	3,372	—
Other taxes payable	4,145	3,388
Derivative financial instruments <i>[note 10]</i>	3,081	5,696
Long-term debt, current	8,199	8,192
Current liabilities of discontinued operations <i>[note 5]</i>	—	197
	34,951	41,218
Long-term debt, non-current	82,378	82,761
Regulatory and other liabilities	10,026	10,892
Future income taxes	20,403	20,736
	147,758	155,607
EQUITY		
Preferred shares	5,000	5,000
Common shares <i>[note 8]</i>	9,343	9,038
Contributed surplus <i>[note 9]</i>	6,082	4,515
Retained earnings	89,949	75,490
Total shareholders' equity	110,374	94,043
Non-controlling interest	276	274
	110,650	94,317
	258,408	249,924

Commitments *[note 13]* and Subsequent Events *[note 16]*

The accompanying notes to the interim consolidated financial statements are an integral part of these financial statements.

On behalf of the Board:

“Roy G. Dyce”

Director

“Robert F. Chase”

Director

Pacific Northern Gas Ltd.
CONSOLIDATED STATEMENTS OF EQUITY
Three months ended March 31
(Unaudited)

[\$ in thousands]	2011	2010
Preferred shares		
Balance, beginning and end of period	5,000	5,000
Common shares		
Balance, beginning of period	9,038	8,890
Employee stock options exercised	305	81
Balance, end of period	9,343	8,971
Contributed surplus		
Balance, beginning of period	4,515	3,699
Stock option expense <i>[note 9]</i>	54	46
Employee stock options exercised	1,513	351
Balance, end of period	6,082	4,096
Retained earnings		
Balance, beginning of period	75,490	72,847
Net income attributable to shareholders	26,791	5,488
Dividends – common shares	(12,332)	(1,005)
Balance, end of period	89,949	77,330
Total shareholders' equity, end of period	110,374	95,397
Non-controlling interest		
Balance, beginning of period	274	—
Net income attributable to non-controlling interest	2	—
Balance, end of period	276	—
Total equity, end of period	110,650	95,397

The accompanying notes to the interim consolidated financial statements are an integral part of these financial statements.

Pacific Northern Gas Ltd.
CONSOLIDATED STATEMENTS OF CASH FLOWS
Three months ended March 31
(Unaudited)

[\$ in thousands]	2011	2010
OPERATING ACTIVITIES		
Net income attributable to shareholders	26,791	5,488
(Income) loss from discontinued operations	(20,823)	199
	5,968	5,687
Add (deduct) items not involving cash:		
Future income taxes <i>[note 6]</i>	(189)	813
Depreciation and amortization <i>[note 15]</i>	1,463	1,979
Amortization of termination payment deferral	(423)	—
Share-based compensation <i>[note 9]</i>	72	196
Imputed interest on regulatory assets and liabilities	83	163
Other	76	—
	7,050	8,838
Changes in operating assets and liabilities	(603)	(7,529)
Net cash provided by operating activities of continuing operations	6,447	1,309
Net cash used in operating activities of discontinued operations	(2,856)	(98)
Net cash provided by operating activities	3,591	1,211
INVESTING ACTIVITIES		
Additions to plant, property and equipment	(674)	(915)
Other	(106)	—
Net cash used in investing activities of continuing operations	(780)	(915)
Net cash provided by (used in) investing activities of discontinued operations	29,706	(248)
Net cash provided by (used in) investing activities	28,926	(1,163)
FINANCING ACTIVITIES		
Decrease in bank indebtedness	(4,836)	(118)
Debt refinancing costs	—	(115)
Repayment of long-term debt	(395)	—
Employee stock options exercised <i>[note 9]</i>	1,818	432
Dividends paid	(12,332)	(1,005)
Net cash used in financing activities of continuing operations	(15,745)	(806)
Decrease in cash from continuing operations	(10,078)	(410)
Increase (decrease) in cash from discontinued operations	26,850	(348)
Increase (decrease) in cash and cash equivalents	16,772	(758)
Cash and cash equivalents, beginning of period	1,301	1,480
Cash and cash equivalents, end of period	18,073	722

Supplemental cash flow information *[note 15]*

The accompanying notes to the interim consolidated financial statements are an integral part of these financial statements.

Pacific Northern Gas Ltd.
NOTES TO INTERIM CONSOLIDATED FINANCIAL STATEMENTS
For the three months ended March 31, 2011
(Unaudited)

1. DESCRIPTION OF THE BUSINESS

Pacific Northern Gas Ltd. (the “Company”) and its wholly-owned subsidiary, Pacific Northern Gas (N.E.) Ltd. (“PNG (N.E.)”), are engaged in the transportation and distribution of natural gas in northern British Columbia, Canada. The Company and PNG (N.E.) are subject to regulation by the British Columbia Utilities Commission (the “Commission”) which, among other things, approves rates charged to customers.

The Company operates a transmission and distribution system in the west-central portion of northern British Columbia (“Western system”) and PNG (N.E.) operates a distribution system in northeastern British Columbia (“Northeast system”). Together, the Company and PNG (N.E.) operate over 3,500 kilometres of transmission and distribution pipeline and serve a base of more than 39,000 residential, commercial and industrial customers.

In April 2010, the Company and Skookum Power Holdings Corp. acquired a 100% interest in the McNair Creek 9.8 megawatt ‘run of river’ hydro-electricity generation facility located on British Columbia’s Sunshine Coast. Through a series of restructuring transactions completed in December 2010, the Company and Skookum Power Holdings Corp., directly and respectively, own 97.1% and 2.9% of McNair Creek Hydro Limited Partnership and its general partner, McNair Creek Hydro Holding Corp. McNair Creek is a non-regulated business and currently operates under a long-term supply agreement with BC Hydro. The investment in McNair Creek represents the launch of the Company’s renewable power business as part of its business diversification strategy. The key elements of this strategy are to diversify the Company’s risk profile, grow its asset base and enhance its earnings and cash flows.

On March 2, 2011, the Company completed the sale of its interest in both Pacific Trail Pipelines Limited Partnership and its general partner, Pacific Trails Pipelines Management Inc. In accordance with the accounting standard for discontinued operations, the results of operations related to those dispositions have been excluded from continuing operations and reported as discontinued operations for all periods presented.

2. BASIS OF PRESENTATION

These interim consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles (“GAAP”) as specified in Part V of the Canadian Institute of Chartered Accountants (“CICA”) Handbook (see note 4), including selected accounting treatments that differ from those used by entities not subject to rate regulation, except that disclosures do not conform, in all respects, to the requirements for annual consolidated financial statements.

These interim consolidated financial statements follow the same accounting policies and methods of their application as the Company’s most recent annual consolidated financial statements for the year ended December 31, 2010.

While management believes that the disclosures presented are adequate to make the information not misleading, these interim consolidated financial statements and notes should be read in conjunction with the Company’s most recent annual audited consolidated financial statements for the year ended December 31, 2010.

Earnings for interim reporting periods may not be indicative of results for the fiscal year due to weather variations and other factors. Specifically, due to the seasonal nature of the sale of natural gas for heating purposes, the Company generally reports net income in the first and fourth quarters of the year, and losses in the second and third quarters.

All financial figures are presented in Canadian dollars.

Pacific Northern Gas Ltd.
NOTES TO INTERIM CONSOLIDATED FINANCIAL STATEMENTS
For the three months ended March 31, 2011
(Unaudited)

3. PRINCIPLES OF CONSOLIDATION

These consolidated financial statements include the accounts of the Company, its wholly-owned subsidiary, PNG (N.E.), its 97.1% owned subsidiary, McNair Creek, as well as the Company's proportionate share of its 50% investment in the assets, liabilities, revenues and expenses of both Pacific Trail Pipelines Limited Partnership and Pacific Trail Pipelines Management Inc. until their disposal on March 2, 2011 as disclosed in note 5.

The results of operations, cash flows, financial position and non-controlling interest of McNair Creek have been included in these financial statements from the date of acquisition, April 19, 2010.

All intercompany transactions and balances are eliminated.

4. ACCOUNTING CHANGES

Changes applied in 2011

2011 REVENUE REQUIREMENT APPLICATION CHANGES

Effective January 1, 2011, the Company adopted the following new accounting policies and changes in accounting estimates on a prospective basis in accordance with its 2011 revenue requirement applications filed with the Commission. These changes in depreciation, capitalization of overheads and accounting for non-pension post-retirement benefits were accepted under negotiated settlements reached on April 27, 2011. The Commission is expected to approve the settlements by the end of May 2011.

Depreciation of plant and equipment is recorded on a straight-line basis over the underlying assets' useful lives. Effective January 1, 2011, the Company implemented the recommendations of a recently completed depreciation study which resulted in adjustments to the estimated remaining useful lives of plant and equipment assets. For 2011, these changes are expected to result in a net decrease in depreciation expense of approximately \$2 million.

Other changes as reflected in the Company's 2011 revenue requirements applications include a reduction in the pool of overhead costs subject to capitalization as part of the cost of plant and equipment and the inclusion of the full actuarially-determined expense for non-pension post-employment benefit plans. As noted, all of these changes were adopted on a prospective basis and are not expected to impact net earnings due to their inclusion in the 2011 revenue requirements applications.

Pacific Northern Gas Ltd.
NOTES TO INTERIM CONSOLIDATED FINANCIAL STATEMENTS
For the three months ended March 31, 2011
(Unaudited)

4. ACCOUNTING CHANGES (continued)

CANADIAN ACCOUNTING STANDARD CHANGES

Comprehensive Revaluation of Assets and Liabilities

In August 2009, the CICA amended Handbook Section 1625, *Comprehensive Revaluation of Assets and Liabilities*, as a result of issuing Sections 1582, *Business Combinations*, 1601, *Consolidated Financial Statements*, and 1602, *Non-Controlling Interests*, in January 2009. The amendments require that when push-down accounting is used following the acquisition of an enterprise, the assets and liabilities are to be measured at the values used in accounting for the purchase transaction or transactions in accordance with Section 1582. The amendments also require that, when a future income tax asset that arose prior to the date of a comprehensive revaluation and that was not recognized in the comprehensive revaluation is subsequently recognized, the benefit should be recognized in accordance with Section 1582 and Section 3465, *Income Taxes*. The amendments apply prospectively to comprehensive revaluations of assets and liabilities occurring in fiscal years beginning on or after January 1, 2011. The adoption of the amendments to Section 1625 had no effect on the Company's consolidated financial statements.

Financial Instruments – Recognition and Measurement

In June 2009, the CICA provided a clarification to Handbook Section 3855, *Financial Instruments – Recognition and Measurement*, with respect to the embedded prepayment option. The Section has been amended to clarify when an embedded prepayment option is separated from its host instrument for accounting purposes. The amendment states that if the exercise price of a prepayment option compensates the lender for an amount equivalent to the present value of the lost interest for the remaining term of the host instrument, the feature is considered closely related to the host contract in which it is embedded. The amendment applies to interim and annual financial statements relating to fiscal years beginning on or after January 1, 2011. The adoption of the amendments to Section 3855 had no effect on the Company's consolidated financial statements.

Multiple Deliverable Revenue Arrangements

In December 2009, the CICA issued EIC-175, *Multiple Deliverable Revenue Arrangements*, replacing EIC-142, *Revenue Arrangements with Multiple Deliverables*. The changes were made in response to changes made to Accounting Standards Codification Topic 605-25, *Revenue Recognition – Multiple Element Arrangements*, under US GAAP, and more closely aligns the accounting requirements for multiple-element arrangements under Canadian GAAP and IFRS. EIC-175 addresses how to determine whether an arrangement involving multiple deliverables contains more than one accounting unit and, if so, how the consideration specified in the multiple element arrangement should be distributed between different accounting units. These recommendations are to be applied prospectively to revenue arrangements with multiple deliverables entered into or materially modified in the first annual fiscal period beginning on or after January 1, 2011. The adoption of EIC-175 had no effect on the Company's consolidated financial statements.

Pacific Northern Gas Ltd.
NOTES TO INTERIM CONSOLIDATED FINANCIAL STATEMENTS
For the three months ended March 31, 2011
(Unaudited)

4. ACCOUNTING CHANGES (continued)

Future accounting pronouncements

International Financial Reporting Standards

The Canadian Accounting Standards Board (“AcSB”) has determined that publicly accountable enterprises are required to prepare financial statements in accordance with International Financial Reporting Standards (“IFRS”) for years beginning on or after January 1, 2011. However, in September 2010 the AcSB issued an amendment to Part I of the CICA Handbook allowing a one-year deferral of first-time adoption of IFRS for qualifying entities with rate-regulated activities.

The Company is a qualifying entity for purposes of this amendment, has elected to make use of the one-year deferral, and has a conversion date for reporting under IFRS of January 1, 2012. Accordingly, the Company’s interim and annual financial statements for fiscal 2011 will be prepared in accordance with Canadian generally accepted accounting principles as defined by Part V of the CICA Handbook.

The Company has amended its transition plan for this deferral and is continuing to evaluate the impacts of the transition to IFRS on its consolidated financial statements.

5. DISCONTINUED OPERATIONS

On March 2, 2011, PNG completed the sale of its 50% joint venture interests in both Pacific Trails Pipeline Limited Partnership (“PTPLP”) and Pacific Trails Pipeline Management Inc. (“PTPMI”). These entities were established to develop a proposed 463 kilometre natural gas pipeline in central British Columbia, from Kitimat to Summit Lake (“KSL Project”). The Company’s interests in the KSL Project were purchased by its partners in the project, Apache Canada Ltd. and EOG Resources Canada Inc.

The transaction has two components, the first being a cash payment of \$30.4 million that the Company received on close, and the second being a cash payment of \$20.0 million to be paid contingent on the purchasers making a decision to proceed with construction of a liquefied natural gas (“LNG”) facility in Kitimat. The Company recorded initial sales proceeds of \$30.4 million on this transaction, and a resulting pre-tax gain of \$24.2 million in the consolidated statement of income during the first quarter of 2011, net of \$5.2 million in transaction costs incurred in connection with the sale, including incentive compensation of \$4.0 million and professional advisory fees and other related costs of \$1.2 million. The Company recorded a related income tax provision of \$2.6 million, for a net after-tax gain of \$21.5 million on the transaction. The Company can give no assurances that construction of the Kitimat LNG facility will be completed or that the contingent \$20.0 million payment will be made. This amount will be recognized in the consolidated statements of income when the contingency is resolved.

In accordance with the accounting standard for discontinued operations, certain financial figures for fiscal 2010 have been reclassified, including the reclassification of assets and liabilities related to these investments as assets and liabilities of discontinued operations, and the reclassification of operating results related to these investments to net income (loss) and comprehensive income (loss) from discontinued operations.

Pacific Northern Gas Ltd.
NOTES TO INTERIM CONSOLIDATED FINANCIAL STATEMENTS
For the three months ended March 31, 2011
(Unaudited)

5. DISCONTINUED OPERATIONS (continued)

The following is a summary of financial information for the discontinued investments in PTPLP and PTPMI:

[\$ in thousands]	March 31 2011	December 31 2010
Assets of discontinued operations		
Cash and cash equivalents	—	593
Accounts receivable	—	1
Current assets of discontinued operations	—	594
Property, plant and equipment	—	684
	—	1,278
Current liabilities of discontinued operations		
Accounts payable and accrued liabilities	—	197

[\$ in thousands]	Three months ended March 31	
	2011	2010
Gain on disposal	24,166	—
Project development expenditures	(738)	(276)
Income (loss) before income taxes	23,428	(276)
Income tax (expense) recovery	(2,605)	77
Net income (loss) and comprehensive income (loss) from discontinued operations	20,823	(199)

Disposition equation

[\$ in thousands]	
Proceeds from sale	30,388
Net book value	(1,027)
Transaction costs	(5,195)
Gain on disposal	24,166

Pacific Northern Gas Ltd.
NOTES TO INTERIM CONSOLIDATED FINANCIAL STATEMENTS
For the three months ended March 31, 2011
(Unaudited)

6. INCOME TAX EXPENSE

	Three months ended March 31	
[\$ in thousands]	2011	2010
Current income tax expense	2,213	1,345
Future income tax expense (recovery)	(189)	813
	2,024	2,158

7. EARNINGS PER COMMON SHARE

	Three months ended March 31	
[\$ in thousands, except share and per share amounts]	2011	2010
Net income from continuing operations	5,970	5,687
Net income (loss) from discontinued operations	20,823	(199)
Net income	26,793	5,488
Net income attributable to non-controlling interest	(2)	—
Dividends on preferred shares	(84)	(84)
Net income attributable to common shares	26,707	5,404
Basic weighted-average number of shares outstanding	3,645,902	3,577,144
Effect of dilutive securities:		
Stock options	113,652	76,710
Diluted weighted-average number of shares outstanding	3,759,554	3,653,854
Basic earnings (loss) per common share:		
From continuing operations	1.61	1.57
From discontinued operations	5.71	(0.06)
	7.32	1.51
Diluted earnings (loss) per common share:		
From continuing operations	1.57	1.53
From discontinued operations	5.54	(0.05)
	7.11	1.48

For the three months ended March 31, 2011, no stock options have been excluded from the computation of diluted weighted-average number of shares outstanding because the exercise prices of these options were lower than the average market price of the Company's common shares during this period.

For the three months ended March 31, 2010, 38,300 stock options have been excluded from the computation of diluted weighted-average number of shares outstanding because the exercise prices of these options were greater than the average market price of the Company's common shares during this period.

Pacific Northern Gas Ltd.
NOTES TO INTERIM CONSOLIDATED FINANCIAL STATEMENTS
For the three months ended March 31, 2011
(Unaudited)

8. COMMON SHARES

[\$ in thousands, except number of shares]	Number of shares	Share capital
Balance, December 31, 2009	3,555,964	8,890
Issue of shares under share option plan	59,180	148
Balance, December 31, 2010	3,615,144	9,038
Issue of shares under share option plan	121,860	305
Balance, March 31, 2011	3,737,004	9,343

During the three months ended March 31, 2011, the Company issued 121,860 common shares on the exercise of stock options (2010 – 32,600).

9. SHARE-BASED COMPENSATION

Stock Option Plan

During the three month period ended March 31, 2011, the Company issued 34,500 stock options with a total fair value of \$106,000 (2010 – 38,300 stock options with a total fair value of \$102,000). The fair value of option awards is estimated on the date of the grant using the Black-Scholes option pricing model. The following weighted-average assumptions were used in computing the fair value of share options granted for the periods noted:

	Three months ended March 31	
	2011	2010
Number of options awarded	34,500	38,300
Stock option fair value	\$3.08	\$2.66
Stock option exercise price	\$26.27	\$22.72
Expected volatility (annualized)	20.0%	20.2%
Dividend yield	4.6%	4.9%
Risk free interest rate	2.8%	3.1%
Estimated option life (years)	7.5	7.5

The share-based compensation expense recorded for the three months ended March 31, 2011 was \$54,000 (2010 - \$46,000).

Pacific Northern Gas Ltd.
NOTES TO INTERIM CONSOLIDATED FINANCIAL STATEMENTS
For the three months ended March 31, 2011
(Unaudited)

9. SHARE-BASED COMPENSATION (continued)

The following table provides a summary of the changes to the Company's share option plan during the periods noted:

	Three months ended March 31			
	2011	Weighted- average exercise price [\$]	2010	Weighted- average exercise price [\$]
	Number of options		Number of options	
Outstanding, beginning of period	311,360	16.92	332,240	15.85
Granted	34,500	26.27	38,300	22.72
Exercised	(121,860)	14.92	(32,600)	13.24
Outstanding, end of period	224,000	19.44	337,940	16.87
Weighted-average exercise price of options exercisable at end of period		18.93		16.71

The following table summarizes information about share options outstanding and exercisable as at March 31, 2011:

Exercise price [\$]	Number of options outstanding	Weighted- average exercise price [\$]	Weighted- average remaining life [years]	Number of options exercisable
12.24 – 14.99	42,300	12.34	7.6	17,180
15.00 – 19.99	92,500	18.59	5.7	84,640
20.00 – 24.99	54,700	22.08	6.9	31,720
25.00 – 26.27	34,500	26.27	10.0	6,900
	224,000	19.44	7.0	140,440

Pacific Northern Gas Ltd.
NOTES TO INTERIM CONSOLIDATED FINANCIAL STATEMENTS
For the three months ended March 31, 2011
(Unaudited)

9. SHARE-BASED COMPENSATION (continued)

Deferred Share Unit Plan

The following table provides a summary of the changes to the Company's deferred share unit plan:

[Units]	Three months ended March 31	
	2011	2010
Outstanding, beginning of period	31,146	24,545
Issued	5,465	2,218
Outstanding, end of period	36,611	26,763

The following table provides a summary of the changes to the liability associated with the Company's deferred share unit plan:

[\$ in thousands]	Three months ended March 31	
	2011	2010
Balance, beginning of period	934	460
Expensed	18	150
Balance, end of period	952	610

10. FINANCIAL INSTRUMENTS

Financial instruments by category

The fair value of the Company's financial instruments, including derivatives, reflects point-in-time estimates based on information about the instruments as at the balance sheet dates. The estimates involve uncertainties and judgment and may not be relevant in predicting future earnings or cash flows.

Non-derivative financial instruments

The Company has designated its non-derivative financial instruments as follows:

[\$ in thousands]	March 31, 2011		December 31, 2010	
	Carrying value	Estimated fair value	Carrying value	Estimated fair value
Held for trading				
Cash and cash equivalents ⁽¹⁾	18,073	18,073	1,894	1,894
Loans and receivables				
Accounts receivable ⁽¹⁾	23,021	23,021	23,017	23,017
Other financial liabilities				
Bank indebtedness	—	—	4,836	4,836
Accounts payable and accrued liabilities ⁽¹⁾	16,154	16,154	19,106	19,106
Long-term debt, including current portion	90,577	102,057	90,953	100,735

⁽¹⁾ December 31, 2010 comparative figures include amounts classified with current assets and current liabilities of discontinued operations (note 5).

Pacific Northern Gas Ltd.
NOTES TO INTERIM CONSOLIDATED FINANCIAL STATEMENTS
For the three months ended March 31, 2011
(Unaudited)

10. FINANCIAL INSTRUMENTS (continued)

The fair values of financial instruments included in current assets and current liabilities in the Company's interim consolidated balance sheets approximate their carrying value, reflecting the short-term maturity of these instruments. The fair value of the Company's long-term debt is estimated by reference to quoted market prices for similar instruments, taking into account credit risk.

Derivative financial instruments

The Company hedges exposures to fluctuations in natural gas prices through the use of derivative financial instruments. The Company has two hedge lines of credit, each is secured by the pledge of a \$20.0 million debenture. One line is with the provider of the Company's bank operating line and the other is with another Canadian bank. Under either hedge line if the credit exposure of the provider exceeds \$20.0 million, the Company is required to provide cash collateral to the extent of the excess credit exposure.

The facility with the Company's operating line provider has one financial covenant which requires the Company's debt leverage not to exceed 65 percent. The second facility, arranged in January 2010, has two financial covenants, one which requires the Company's debt leverage not to exceed 65 percent, and the second which requires the Company to maintain a minimum interest coverage of 1.5 times using earnings before interest, income taxes and expenditures on the KSL Project to a maximum of \$10.0 million. Further, if the Company's secured debt rating is less than BBB (low) or the Company has no debt rating, the interest coverage requirement is 2.0 times or higher.

The risk management facilities allow the Company to hedge natural gas purchases in accordance with its annual gas contracting and gas supply price risk management plan and to enter into interest rate hedging transactions.

The following tables summarize the valuation of the Company's derivative financial instruments related to natural gas supply as at the dates noted:

As at March 31, 2011

Financial instrument	Notional quantity (gigajoules)	Percent of annual gas purchases (%)	Delivery period	Price range (per gigajoule)	Estimated net fair value receivable (payable) (\$000's)
Natural gas swap contracts	3 175 500	34.1	Apr 2011 – Oct 2012	\$3.94 to \$6.49	(3,399)
Collar contracts	53 500	0.6	Apr 2012 – Oct 2012	\$3.80 (floor) to \$5.81(cap)	(12)
	3 229 000	34.7			(3,411)

Of the \$3.4 million liability at March 31, 2011, \$3.1 million is recorded as a current liability and \$0.3 million recorded in non-current regulatory and other liabilities on the interim consolidated balance sheet.

Pacific Northern Gas Ltd.
NOTES TO INTERIM CONSOLIDATED FINANCIAL STATEMENTS
For the three months ended March 31, 2011
(Unaudited)

10. FINANCIAL INSTRUMENTS (continued)

As at December 31, 2010

Financial instrument	Notional quantity (gigajoules)	Percent of annual gas purchases (%)	Delivery period	Price range (per gigajoule)	Estimated net fair value receivable (payable) (\$000's)
Fixed-price contracts	900 000	9.4	Jan 2011 – Mar 2011	\$4.23	(678)
Natural gas swap contracts	3 846 600	40.2	Jan 2011 – Oct 2012	\$4.16 to \$7.26	(5,453)
Collar contracts	53 500	0.6	Apr 2012 – Oct 2012	\$3.80 (floor) - \$5.81 (cap)	(8)
	4 800 100	50.2			(6,139)

Of the \$6.1 million net liability at December 31, 2010, \$0.1 million is recorded as a current asset, \$5.7 million is recorded as a current liability and \$0.5 million is recorded in non-current regulatory and other liabilities on the interim consolidated balance sheet.

The fair values reflect the estimated amounts that the Company would receive or pay at the period end to terminate the fixed-price, swap or collar contracts based on the estimated future net cash flows under the terms of each contract.

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

11. RISK MANAGEMENT

Credit risk

The Company is exposed to credit risk in the event that a customer or counterparty to a financial instrument fails to meet its contractual obligations and arises mainly from its accounts receivable and derivative financial instruments. In accordance with established credit approval practices, the Company deals only with recognized high credit quality institutions as counterparties to its derivative instruments and physical off system gas sales and does not expect any counterparties to fail to meet its obligations. Should the Company incur a financial loss with respect to its regulated operations as a result of the failure of counterparty to meet its obligations, the Company would require regulatory approval to recover related costs through future rate adjustments.

The Company's credit policy requires a review of each customer for creditworthiness and often will require residential and commercial customers to pay a customer deposit based on two times the highest estimated monthly gas consumption prior to the installation of service. For industrial customers, the Company has the right to require securities such as letters of credit should a customer fail to pay its bills. No letters of credit or alternate security are currently in place with any individual industrial customer.

The Company establishes an allowance for doubtful accounts that represents its estimate of accounts receivable which may not be recoverable. The main components of this allowance are a specific provision that relates to individual significant exposures and a general provision for the core market (residential and commercial) customers based on past experience. The Company actively reviews the adequacy of its allowance for doubtful accounts.

Pacific Northern Gas Ltd.
NOTES TO INTERIM CONSOLIDATED FINANCIAL STATEMENTS
For the three months ended March 31, 2011
(Unaudited)

11. RISK MANAGEMENT (continued)

The following table shows the breakdown of accounts receivables by major customer class:

[\$ in thousands]	March 31 2011	December 31 2010
Core market – residential and commercial	20,874	19,581
Industrial customers	1,187	779
Off-system sales customers	1,418	3,167
Other	402	338
	23,881	23,865
Less: Allowance for doubtful accounts	(860)	(849)
	23,021	23,016

The following table sets forth details of the aging of accounts receivables:

[\$ in thousands]	March 31 2011	December 31 2010
Unbilled revenues	12,259	11,991
Past due 0 to 30 days (current)	10,738	11,119
Past due 31 to 90 days	419	303
Past due over 91 days	465	452
	23,881	23,865
Less: Allowance for doubtful accounts	(860)	(849)
	23,021	23,016

Changes in the allowance for doubtful accounts are as follows:

[\$ in thousands]	March 31 2011	December 31 2010
Balance, beginning of period	849	2,044
Provision for doubtful accounts	—	265
Write-off of bad debts, net of recoveries, and other	11	(1,460)
Balance, end of period	860	849

Pacific Northern Gas Ltd.
NOTES TO INTERIM CONSOLIDATED FINANCIAL STATEMENTS
For the three months ended March 31, 2011
(Unaudited)

11. RISK MANAGEMENT (continued)

Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet obligations associated with financial liabilities and commitments as they become due. The Company manages liquidity risk through the management of its capital structure and financial leverage. It also regularly monitors actual and projected cash flows. The Company believes that future cash flows generated from operations and access to additional liquidity through capital and banking markets will be adequate to meet its financial obligations in the foreseeable future. The Company's overall liquidity risk has improved slightly from December 31, 2010, with the increase in the availability of credit under its risk management facilities, 5-year term revolving debt facility and its operating line, and from the net proceeds of the sale of PTPLP and PTPMI (see note 5).

As at March 31, 2011 the Company had utilized \$3.8 million of its \$25.0 million operating line facility and \$16.0 million of the \$35.0 million available under its revolving term facility.

The Company maintains regular dialogue with the financial institution that provides these facilities and has no reason to believe the facilities will not be renewed upon maturity. See "Market Risk – Interest Rates" below for additional information on how this may impact the Company's future results.

Market risk

Market risk is the risk that changes in market prices, including foreign exchange, interest rates and commodity prices will affect the fair value of the Company's financial instruments. The Company is not exposed to any foreign exchange risks on its earnings. The Company's overall market risk has not changed significantly from December 31, 2010.

Market risk – commodity prices

The commodity cost of natural gas can be highly volatile. The Company utilizes derivative and other financial instruments in connection with the management of gas supply. 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. Based on the current regulatory process, any gains or losses arising from utility related derivative financial instruments are treated as part of the flow through of gas supply costs in customer rates.

The commodity price for electricity can also be volatile. However, as all of the electricity generated by the McNair Creek facility is sold under a long-term fixed-price contract, exposure to market price changes for this non-regulated activity is considered to be negligible.

Market risk – interest rates

While underlying interest rates, such as prime and bankers' acceptances rates are subject to changes in the future, as are interest rate spreads on borrowings by the Company, the Company does not expect these changes to have a material impact on its financial results. As directed by the Commission, the Company has an interest deferral mechanism that mitigates exposure to fluctuations in floating rates on both short-term and long-term debt instruments.

Pacific Northern Gas Ltd.
NOTES TO INTERIM CONSOLIDATED FINANCIAL STATEMENTS
For the three months ended March 31, 2011
(Unaudited)

12. CAPITAL MANAGEMENT

The Company's objective in managing capital remains largely unchanged from December 31, 2010. The capital structure consisted of the following components at March 31, 2011: bank indebtedness, long-term debt and shareholders' equity, totaling \$201.0 million [2010 – \$172.4 million].

The Company's objectives with its capital structure are:

- to maintain the amount of common equity in its capital structure at the level approved by the Commission for the purpose of determining rates for the Company's regulated operations plus sufficient equity to support investments in the Company's non-regulated businesses; and
- to maintain a credit rating at which the Company has sufficient access to capital and to natural gas and other supplies on reasonable terms to be able to provide safe, secure and reliable service to its customers, which in turn is critical to the Company's ongoing prosperity.

The Company made significant progress in 2010 toward achieving the first objective while simultaneously maintaining its credit rating. Provided that the Company is able to maintain its credit rating, further progress on the first objective is possible through additional investments in renewable power projects.

During the fiscal year ending December 31, 2010 the Company added a second hedge facility, extended and increased the amount available under its revolving term facility and extended and amended its operating line. The hedge facility, arranged in January 2010, has two financial covenants, one which requires the Company's debt leverage not to exceed 65 percent, and the second which requires the Company to maintain an interest coverage of 1.5 times or higher using earnings before interest, income taxes and expenditures on the KSL Project to a maximum of \$10.0 million. Further, if the Company's secured debt rating is less than BBB (low) or the Company has no debt rating, the interest coverage requirement is 2.0 times or higher.

The amendment to the operating line included an increase to \$25.0 million of the credit available to the Company as well as increases in stand-by fees and interest rate spreads to reflect then current market conditions. No changes were made to the financial covenant under the operating line.

The \$25.0 million operating line and \$35.0 million 5-year revolving term facility are subject to a financial covenant requiring the Company's debt leverage not to exceed 65percent. The 5-year revolving term facility contains an additional covenant which states that if the Company's secured debt rating is less than BBB (low) or the Company has no debt rating, the Company must maintain an interest coverage of 2.0 times or higher using earnings before interest, income taxes and expenditures on the KSL Project to a cumulative maximum of \$10.0 million. On May 17, 2010 Dominion Bond Rating Services ("DBRS") confirmed the Company's secured debt ratings at BBB (low). The Company is in compliance with its debt covenants as at March 31, 2011.

Pacific Northern Gas Ltd.
NOTES TO INTERIM CONSOLIDATED FINANCIAL STATEMENTS
For the three months ended March 31, 2011
(Unaudited)

13. COMMITMENTS

The Company has long-term natural gas purchase arrangements all of which are transacted at market prices and in the normal course of business. The Company's purchase commitments as at March 31, 2011 under various gas supply contracts expiring through 2015 were as follows:

[\$ in thousands]

2011	6,559
2012	4,846
2013	51
2014	51
2015	42
Total	11,549

These obligations are based on market prices that vary with gas commodity indices. The amounts disclosed reflect index prices that were in effect as at March 31, 2011.

The Company is required to make annual funding contributions of an estimated \$2.2 million to its pension plan as determined by the actuarial valuation report as at December 31, 2009 which was completed during the third quarter of 2010.

The Company continues to pursue an investment opportunity in the proposed 45 MW Narrows Inlet run-of-river renewable energy project located near Sechelt, British Columbia. The Company has a commitment to invest up to \$2.5 million to advance the Narrows Inlet project to the commencement-of-construction stage which is expected to be achieved by mid-to-late 2012 [see note 16].

14. SEGMENTED INFORMATION

The Company operates in two business segments: the transmission and distribution of natural gas and the generation and sale of electricity from renewable resources. The Company operates in a single geographic segment: Canada.

The segment information does not include the results of business classified as discontinued operations.

Segmented results

The following tables provide segmented financial information for the three months ended March 31, 2011. Comparative information has not been presented as the Company operated in a single business segment during the comparative period in 2010.

Pacific Northern Gas Ltd.
NOTES TO INTERIM CONSOLIDATED FINANCIAL STATEMENTS
For the three months ended March 31, 2011
(Unaudited)

14. SEGMENTED INFORMATION (continued)

Three months ended March 31, 2011

[\$ in thousands]	Gas Transmission and Distribution	Renewable Energy	Consolidated
Revenues	37,038	441	37,479
Cost of gas	19,072	—	19,072
	17,966	441	18,407
Operating and maintenance	3,231	39	3,270
Administrative and general	2,576	32	2,608
Depreciation and amortization	1,334	121	1,455
Municipal and other taxes	1,210	27	1,237
	8,351	219	8,570
	9,615	222	9,837
Finance fees	1,665	178	1,843
Income tax expense	2,018	6	2,024
Net income from continuing operations	5,932	38	5,970

Other segment information regarding capital expenditures, assets and liabilities is as follows:

As at and for the three months ended March 31, 2011

[\$ in thousands]	Gas Transmission and Distribution	Renewable Energy	Consolidated
Capital expenditures	673	1	674
Plant, property & equipment	178,017	19,013	197,030
Assets	237,216	21,192	258,408
Liabilities	135,399	12,359	147,758

As at and for the year ended December 31, 2010

[\$ in thousands]	Gas Transmission and Distribution	Renewable Energy	Consolidated
Capital expenditures	6,896	4	6,900
Plant, property & equipment	177,044	19,132	196,176
Assets	227,475	21,171	248,646
Liabilities	143,034	12,376	155,410

Pacific Northern Gas Ltd.
NOTES TO INTERIM CONSOLIDATED FINANCIAL STATEMENTS
For the three months ended March 31, 2011
(Unaudited)

15. SUPPLEMENTAL CASH FLOW INFORMATION

[\$ in thousands]	March 31 2011	December 31 2010
Cash and cash equivalents:		
Cash	2,069	1,301
Cash equivalents	16,004	—
	18,073	1,301

Cash equivalents are comprised of highly-liquid term investments with original maturities of 90 days or less.

[\$ in thousands]	Three months ended March 31	
	2011	2010
Depreciation and amortization:		
Depreciation and amortization, per income statement	1,455	2,100
Amortization of debt issue costs included in long-term interest expense	8	(121)
Total depreciation and amortization	1,463	1,979

Changes in operating assets and liabilities:

(Increase) decrease in:		
Accounts receivable	(5)	4,809
Gas purchase variance recoverable	—	—
Income taxes recoverable	1,305	—
Inventories of supplies and natural gas	(173)	136
Prepaid expenses	260	(25)
Increase (decrease) in:		
Accounts payable and accrued liabilities	(5,190)	(8,578)
Gas purchase variance payable	(92)	(758)
Income taxes payable	762	132
Other taxes payable	756	(718)
Changes in regulatory assets and liabilities	2,015	(2,416)
Contributions to defined benefit plans in excess of expense	(241)	(111)
Attributable to operating activities	(603)	(7,529)

Interest and tax payments:

Income taxes paid	146	1,923
Interest paid	1,243	1,016

Non-cash transactions:

Plant, property and equipment purchases included in accounts payable and accrued liabilities	81	16
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Pacific Northern Gas Ltd.
NOTES TO INTERIM CONSOLIDATED FINANCIAL STATEMENTS
For the three months ended March 31, 2011
(Unaudited)

16. SUBSEQUENT EVENTS

Special Dividend

On May 11, 2011, the Company's Board of Directors declared a special dividend of \$3.00 per common share payable June 21, 2011 to shareholders of record at the close of business on June 6, 2011. This amount represents approximately \$11 million of the initial proceeds of \$30 million received on March 2, 2011 in connection with the sale of the Company's 50 percent interest in both PTPLP and PTPMI [see note 5].

Narrows Inlet Project

The Company continues to advance its renewable energy strategy with a further investment in the 45 MW Narrow Inlet run-of-river renewable energy project ("NI Project"), also referred to as the Stl'ixwim Renewable Energy Initiative or the Stl'ixwim Project. Subsequent to March 31, 2011, the Company formed Narrows Inlet Limited Partnership ("NILP") with Skookum Power Corp. to undertake future investment in the NI Project, and made an initial capital contribution of \$0.3 million representing a 98% interest in the partnership. These funds are in addition to a previous investment of \$0.3 million in flow-through shares related to this project and will be used as part of a commitment to invest up to \$2.5 million to advance the NI Project to the commencement-of-construction stage which is expected to be achieved by mid-to-late 2012. Prior to the commencement of construction, the Company will make its final investment decision, and through NILP, will have an exclusive option to provide the construction equity as well as an option to ensure NILP owns a 50% interest in the NI Project.

The NI Project consists of five proposed developments situated on four creeks that are located within a radius of 5 to 8 km of each other at the northern end of Narrows Inlet, which is located approximately 35 km north of the town of Sechelt, British Columbia. The NI Project will benefit from coastal precipitation patterns, some storage capacity and close proximity to the largest electricity load center in British Columbia. The NI Project was awarded a 30 year energy purchase agreement with B.C. Hydro in the spring of 2010.

17. COMPARATIVE FIGURES

Certain of the prior period's comparative figures have been reclassified to conform to the financial presentation adopted in the current year.

PACIFIC NORTHERN GAS LTD.
FORM 52-109F2
CERTIFICATION OF INTERIM FILINGS

I, Roy Dyce, the Chief Executive Officer of Pacific Northern Gas Ltd., certify the following:

1. **Review:** I have reviewed the interim financial report and interim MD&A (together, the “interim filings”) of Pacific Northern Gas Ltd., (“the issuer”) for the interim period ended March 31, 2011.
2. **No misrepresentations:** Based on my knowledge, having exercised reasonable diligence, the interim filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by the interim filings.
3. **Fair presentation:** Based on my knowledge, having exercised reasonable diligence, the interim financial report together with the other financial information included in the interim filings fairly present in all material respects the financial condition, financial performance and cash flows of the issuer, as of the date of and for the periods presented in the interim filings.
4. **Responsibility:** The issuer’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (DC&P) and internal control over financial reporting (ICFR), as those terms are defined in National Instrument 52-109 Certification of Disclosure in Issuers’ Annual and Interim Filings, for the issuer.
5. **Design:** Subject to the limitations, if any, described in paragraphs 5.2 and 5.3, the issuer’s other certifying officer and I have, as at the end of the period covered by the interim filings
 - (a) designed DC&P, or caused it to be designed under our supervision, to provide reasonable assurance that
 - (i) material information relating to the issuer is made known to us by others, particularly during the period in which the interim filings are being prepared; and
 - (ii) information required to be disclosed by the issuer in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in securities legislation; and
 - (b) designed ICFR, or caused it to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with the issuer’s GAAP.
- 5.1 **Control framework:** The control framework the issuer’s other certifying officer and I used to design the issuer’s ICFR is the Committee of Sponsoring Organizations of the Treadway Commission (COSO) Internal Control – Integrated Framework.
- 5.2 **ICFR – material weakness relating to design:** N/A

5.3 **Limitation on scope of design:** N/A

6. **Reporting changes in ICFR:** The issuer has disclosed in its interim MD&A any change in the issuer's ICFR that occurred during the period beginning on January 1, 2011 and ended on March 31, 2011 that has materially affected, or is reasonably likely to materially affect, the issuer's ICFR.

Date: May 11, 2011

"Roy G. Dyce"

Roy G. Dyce
Chief Executive Officer

PACIFIC NORTHERN GAS LTD.
FORM 52-109F2
CERTIFICATION OF INTERIM FILINGS

I, Janet P. Kennedy, the Vice President, Finance of Pacific Northern Gas Ltd. (certifying as the chief financial officer of the Company), certify the following:

1. **Review:** I have reviewed the interim financial report and interim MD&A (together, the “interim filings”) of Pacific Northern Gas Ltd., (“the issuer”) for the interim period ended March 31, 2011.
2. **No misrepresentations:** Based on my knowledge, having exercised reasonable diligence, the interim filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by the interim filings.
3. **Fair presentation:** Based on my knowledge, having exercised reasonable diligence, the interim financial report together with the other financial information included in the interim filings fairly present in all material respects the financial condition, financial performance and cash flows of the issuer, as of the date and for the periods presented in the interim filings.
4. **Responsibility:** The issuer’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (DC&P) and internal control over financial reporting (ICFR), as those terms are defined in National Instrument 52-109 *Certification of Disclosure in Issuers’ Annual and Interim Filings*, for the issuer.
5. **Design:** Subject to the limitations, if any, described in paragraphs 5.2 and 5.3, the issuer’s other certifying officer and I have, as at the end of the period covered by the interim filings
 - (a) designed DC&P, or caused it to be designed under our supervision, to provide reasonable assurance that
 - (i) material information relating to the issuer is made known to us by others, particularly during the period in which the interim filings are being prepared; and
 - (ii) information required to be disclosed by the issuer in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in securities legislation; and
 - (b) designed ICFR, or caused it to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with the issuer’s GAAP.
- 5.1 **Control framework:** The control framework the issuer’s other certifying officer and I used to design the issuer’s ICFR is the Committee of Sponsoring Organizations of the Treadway Commission (COSO) Internal Control – Integrated Framework.
- 5.2 **ICFR – material weakness relating to design:** N/A

5.3 **Limitation on scope of design:** N/A

6. **Reporting changes in ICFR:** The issuer has disclosed in its interim MD&A any change in the issuer's ICFR that occurred during the period beginning on January 1, 2011 and ended on March 31, 2011 that has materially affected, or is reasonably likely to materially affect, the issuer's ICFR.

Date: May 11, 2011

"Janet Kennedy"

Janet Kennedy
Vice President, Finance
(certifying as chief financial officer)