

Management's Discussion and Analysis

**Pacific Northern Gas Ltd.**

December 31, 2010



**PACIFIC NORTHERN GAS LTD.  
MANAGEMENT’S DISCUSSION AND ANALYSIS  
DECEMBER 31, 2010**

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**Date: March 3, 2011**

This management's discussion and analysis ("MD&A") should 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") 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](http://www.sedar.com).

### **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 application (see "Regulatory Activities");
- The timing of the closing of the sale of the Company's interest in Pacific Trail Pipelines Limited Partnership ("PTP") and receipt of payments (see "Business Overview – 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");
- Growth of opportunities in renewable energy generation;
- The benefits of the acquisition of the McNair Creek hydroelectric generation facility (see "Business Overview - Renewable Energy Business");
- The regulatory treatment of the West Fraser 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 impact of economic conditions on the Company's performance and prospects for growth;
- 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 application;
- 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 2010 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.

References to “net earnings before acquisition and reorganization costs” and “net earnings before acquisition and reorganization costs per share” represent pro forma earnings and earnings per share measures based on net earnings before deduction of acquisition and reorganization costs incurred. These pro forma measures are not recognized measures under Canadian GAAP and do not have standardized meanings prescribed by Canadian GAAP. Therefore, net earnings before acquisition and reorganization costs and net earnings before acquisition and reorganization costs per share may not be comparable to similar measures presented by other issuers. Readers are cautioned that net earnings before acquisition and reorganization costs and net earnings before acquisition and reorganization costs per share should not replace net earnings and earnings per share as measures of performance. Management believes net earnings before acquisition and reorganization costs and net earnings before acquisition and reorganization costs per share are meaningful measures of performance for the Company’s recently acquired McNair hydroelectric facility as it removes the impact of one-time acquisition and reorganization costs and provides earnings results that might be considered more indicative of future performance.

## **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 McNair Creek hydro-electricity generation facility (“McNair”) located on B.C.’s Sunshine Coast.

## **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 and evaluating development and acquisition opportunities. It is also reviewing its business strategy in light of the recent sale of its interest in the proposed natural gas pipeline from Summit Lake, B.C. to Kitimat, B.C. (“KSL Project”) and the March 2, 2011 receipt of \$30 million of the \$50 million sales price (see “Business Overview – KSL Project” and “Subsequent Event”).

In respect of its strategy, the Company has concluded:

- It must grow profitably and increase its market capitalization in order to enhance shareholder value;
- It is important for the Company to seek growth opportunities in areas that complement its strengths and fit well within its existing risk profile;
- Merger and acquisition opportunities are limited in the Canadian utility sector given the Company’s small relative size; and
- There are two near-term business improvement opportunities in the Company’s service area that would materially benefit the Company and its customers: (i) the LNG Partners small scale LNG project; and (ii) the transportation service agreements for delivery of LNG to supplement the KSL Project and an operating and maintenance agreement for the KSL Project (see “Business Overview – KSL Project” and “Business Overview – Capacity Utilization on the Western System”).

As there are limited opportunities to expand through acquisitions of Canadian natural gas distribution assets, management and the Board of Directors have identified specific parameters for evaluating growth opportunities through electricity and renewable energy generation.

In particular, based on the following factors, it has been determined that renewable independent hydro power development and operation with long-term off-take contracts would provide the best fit for the Company:

- renewable energy is a growth area;
- long term fixed-price off-take agreements are available for independent power projects in a number of Canadian jurisdictions, including British Columbia;
- the technology is well developed and the resource is relatively predictable;
- the Company can utilize its operating skills, permitting expertise, project management capabilities, financing acumen and energy market and regulatory expertise;
- both operating projects and development projects are available in sizes which fit the Company's access to capital; and
- although the Company does not have internal technical expertise for hydro power, it has contracted access to that expertise through an agreement with Skookum Power Corp. ("Skookum Power") and may broaden such access via additional partnerships or acquisitions.

The Company can give no assurances that it will be successful in identifying, financing or realizing value from these opportunities.

The Company has focused on increasing its dividend yield to shareholders to a level more consistent with other publicly-traded utilities. In that regard, the Company announced a quarterly dividend increase in February 2010 to \$0.28 per common share and a further increase in October 2010 to \$0.30 per common share.

## **KSL Project**

PTP is the developer of 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 owned by Apache Canada Ltd. ("Apache Canada") and EOG Resources Canada Inc. ("EOG Canada"). The Kitimat LNG facility and the KSL Project have the support of, and will provide benefits to, many stakeholders including the First Nations with traditional territories in the project area. The Company has held a 50 percent interest in PTP since the KSL Project's inception in 2005.

In the third quarter of 2010, PTP commenced the detailed design phase of the KSL Project and the Company commenced capitalization of these expenditures. The Company's share of expenditures on the KSL Project for the year ended December 31, 2010 was \$1.25 million, including \$0.7 million which has been capitalized relating to engineering and technical studies.

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 (see "Subsequent Event"). This transaction has two components, the first being a cash payment of \$30 million that the Company received on March 2, 2011, and the second being a cash

payment of \$20 million to be paid contingent on the purchasers making a decision to proceed with construction of the Kitimat LNG facility. The Company can give no assurances that construction of the Kitimat LNG facility will be completed or that the \$20 million payment will be made.

As a result of the transaction, Apache Canada's ownership of the pipeline will increase from 25.5 percent to 51 percent and EOG Canada's ownership will increase from 24.5 percent to 49 percent.

The Company's shareholders will benefit from the full crystallization of cash proceeds received on this transaction. The \$50 million sale proceeds have an approximate value of \$9 to \$10 per share after taxes and related expenses, including payments under the KSL Project management incentive plan, should the second contingent payment of \$20 million be released.

The Company has recorded \$7.3 million of KSL Project expenditures from its inception to December 31, 2010, of which \$6.6 million has been expensed and \$0.7 million has been capitalized.

On March 3, 2011, the Company's Board of Directors declared a special dividend of \$3.00 per common share, which represents approximately \$ 11 million of the proceeds from the sale of PTP.

### **Transportation Service Agreements**

In connection with the sale, the Company agreed on the terms for a 20-year transportation service agreement with Apache Canada and EOG Canada that will significantly increase the utilization of the Company's current pipeline in the event that LNG Partners does not claim this capacity first.

If the LNG Partners project does not proceed and the Kitimat LNG facility does proceed, 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 via the Company would be 30 MMcf per day starting with initial LNG production. Delivery of an additional 20 MMcf per day via the Company would commence 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.

### **Operating and Maintenance Agreement**

The Company will operate the KSL Project pipeline under an operating and maintenance agreement negotiated with Apache Canada and EOG Canada. The operating and maintenance agreement will have an initial term of seven years beginning in 2015, with renewal provisions, and will be subject to approval by the Commission.

## **Capacity Utilization on the Western System**

A letter agreement with Merrill Lynch Commodities Inc. (“Merrill Lynch”) provided Merrill Lynch with an option to contract for 75 MMcf per day of firm gas transportation service using existing capacity on the Company’s Western system. The letter agreement also provided for the parties to negotiate a definitive transportation service agreement (“TSA”) for filing with the Commission for acceptance as a filed tariff. The TSA was accepted by the Commission as a filed tariff on June 17, 2010. During final negotiations, the parties agreed to increase the capacity option from 75 to 80 MMcf per day. The TSA documents the option provisions and the transportation service provisions that would apply following exercise of the option. On August 11, 2010 Merrill Lynch assigned and novated the TSA to LNG Partners. If LNG Partners exercises its option, it is expected to utilize the transportation service to deliver natural gas to a small scale LNG facility to be located on the Douglas Channel near Kitimat, B.C. It is expected that the LNG produced at this facility would be exported to LNG markets in Asia.

The Company has received option fees of \$4.5 million to secure an 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**

In April 2010, the Company entered into a joint development and operating agreement with Skookum Power gaining access to extensive expertise in hydrology, engineering and commercial development to support its new renewable energy business platform. The principals of Skookum Power are former power company executives who have collectively more than 50 years experience in the hydro-electricity and energy sectors.

On April 19, 2010, the Company, in partnership with Skookum Power, closed the acquisition of the 9.8 megawatt McNair Creek hydro-electricity generation facility from Kiewit Hydropower Investors Inc. and Renewable Power Corp., with the Company holding a 97% share. The McNair facility is located on B.C.'s Sunshine Coast near Port Mellon and has been in operation for more than 5 years. The facility's generation is committed for sale under a long-term contract to BC Hydro.

The total purchase price was approximately \$17.5 million and has been funded in part by the assumption of \$9.4 million in non-recourse debt and the remainder in cash payments. The Company's cash purchase obligations were met through drawings on its existing credit facilities. The transaction is expected to be cash flow positive for 2011 onwards.

On December 16 and 17, 2010, the McNair Creek Hydro Partnership (a general partnership) was converted to McNair Creek Hydro Limited Partnership through a series of restructuring transactions and the Company became a limited partner owning 97.1% of the limited partnership. The McNair Creek Hydro Limited Partnership was registered under the laws of British Columbia on December 17, 2010. Its main business activity continues to be the operation of the 9.8 MW McNair hydro-electricity generation facility.

### **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. The Company had a transportation service agreement with West Fraser which specified a daily contract demand volume of 6.0 MMcf (million cubic feet) per day that was set to expire on December 31, 2013. Under the terms of the transportation agreement, West Fraser paid the Company an annual demand charge of approximately \$2.1 million and was entitled to cancel its obligations by providing the Company with a termination payment that would recover almost 80 percent of the lost revenues under the remaining term of the agreement.

On May 31, 2010 West Fraser provided the Company with the required six months cancellation notice. West Fraser paid the monthly demand charge due under the transportation agreement until November 2010. A termination payment of \$5.1 million was received on December 1, 2010. The Company expects that the termination payment will be amortized into earnings over the remaining life of the agreement; the same regulatory treatment accorded the Methanex termination payment made in 2006. The Company has sought Commission approval of this treatment in its 2011 revenue requirements application. 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 continuously monitors the competitiveness of its natural gas retail rates relative to alternative heating sources in its service area. 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 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 rate increases have been higher than the impact of the carbon tax on natural gas prices and 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 is seeking Commission approval of a bundled average residential rate of \$20.31 per GJ effective January 1, 2011, including the current carbon tax of \$0.9932 per GJ. This is approximately 5 percent less than the equivalent residential conservation electricity rate of \$21.44 per GJ.

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

## **Negotiated Settlement Agreements – 2010 Revenue Requirements Applications and the Capital Structure and Equity Risk Premium Application (the "CAP/ROE Application")**

On June 23, 2010 the Commission approved the negotiated settlement agreements in respect of the 2010 revenue requirements applications for the Western system and Northeast system and the CAP/ROE Application (the "settlement agreements"). The key matters agreed to under the settlement agreements are summarized as follows:

- The parties agreed the common equity capitalization and risk premiums relative to the benchmark utility return on equity ("ROE") for the Western system division (effective January 1, 2009) and the Fort St. John/Dawson Creek and Tumbler Ridge divisions (effective January 1, 2010) would be as follows:

	<b>Western System Division</b>	<b>Fort St. John/Dawson Creek Division</b>	<b>Tumbler Ridge Division</b>
Common Equity Capitalization	45%	40%	40%
Equity Risk Premiums	65 basis points	40 basis points	65 basis points

On a consolidated basis, this provided the Company with the opportunity to increase overall earnings in 2010 by approximately \$0.6 million or \$0.17 per share. Further, an additional \$0.5 million of net income was included in the second quarter to reflect the January 1, 2009 effective date for the Western system common equity capitalization ratio adjustment.

The equity risk premiums are relative to the benchmark utility ROE of 9.50% that became effective July 1, 2009 resulting in the following ROE's in 2009 and 2010 for each division:

<b>Year</b>	<b>Western System Division</b>	<b>Fort St. John/Dawson Creek Division</b>	<b>Tumbler Ridge Division</b>
2009	9.63%	9.38%	9.63%
2010	10.15%	9.90%	10.15%

The 2009 ROE's are lower than applicable in 2010 to account for the fact the benchmark ROE of 9.50% was made effective July 1, 2009.

- The interim rates effective January 1, 2010 were made permanent for 2010. Having regard to the fact the interim rates were based on forecast 2010 costs of service using common equity capitalization and ROE figures that were less than the agreed to figures, the parties agreed the difference between: (i) the 2010 gross margins using the interim rates; and (ii) the costs of service based on the parameters agreed to under the final settlement agreements would be recorded, for future disposition, in the common equity deferral accounts approved by the Commission under Order G-172-09.
- On December 31, 2010, the Company used a portion of the balance in the LNG Partners option fees deferral account to draw down the remaining \$2.0 million balance in the Western system common equity deferral account as agreed under the Western system negotiated settlement agreement.

## **Overall Performance**

Net income for 2010 was \$7.1 million, compared with \$6.5 million for 2009. After providing for preferred share dividends, basic earnings per common share for 2010 were \$1.88 compared with \$1.72 for 2009. Net income available to common shareholders increased by \$0.6 million mainly due to higher allowed rates of return on common equity, higher common equity components and incremental operating earnings from McNair, partially offset by higher KSL Project development expenses incurred in 2010 compared to 2009 and by costs incurred on the McNair acquisition and reorganization as well as other strategic initiatives.

The allowed weighted-average return on deemed common equity increased from 9.58 percent in 2009 to 10.09 percent in 2010. The increased ROE reflects the impact of the Commission's decision in December 2009 to increase the return on equity for the benchmark low-risk utility in British Columbia from 8.47 percent to 9.50 percent effective July 1, 2009.

Included in net income for 2010 are after-tax charges of \$0.4 million, or \$0.11 per share, compared with after-tax charges of \$0.1 million, or \$0.04 per share for 2009, relating to the Company's share of KSL Project development expenses and after-tax charges of \$0.7 million, or \$0.19 per share relating to the McNair acquisition and subsequent reorganization. The Company's decision to early adopt the new accounting standard for business combinations has resulted in the expensing of \$0.5 million of costs related to the McNair acquisition rather than their inclusion as part of the cost of the business acquisition. If not for the Company's early adoption of this standard, net earnings per common share for the year ended December 31, 2010 would have been \$2.01 instead of \$1.88.

## Selected Annual Information

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

*[\$ in thousands, except TJ\*, customer, per GJ\* and per share figures]*

	2010	2009	2008
Deliveries (TJ):			
Sales – Western system	2 330	2 965	3 070
Sales – Northeast system	3 365	3 765	3 608
Transportation service – Western system	1 867	3 214	3 572
Transportation service – Northeast system	<u>1 925</u>	<u>2 201</u>	<u>2 292</u>
Total	9 487	12 145	12 542
Customers at period end	39 405	39,113	39,113
Weighted average cost of gas purchased (\$ per GJ)	\$5.44	\$6.35	\$7.84
Revenues	\$95,164	\$104,131	\$132,839
Operating margin**, consisting of revenues less cost of gas	\$51 051	\$46,892	\$46,715
Net income attributable to shareholders	\$ 7, 088	\$ 6,532	\$ 5,937
Basic earnings per common share	\$1.88	\$1.72	\$1.53
Diluted earnings per common share	\$1.83	\$1.71	\$1.52
Total assets	\$249,924	\$220,209	\$222,049
Total long-term financial liabilities	\$114 389	\$93,913	\$88,380
Dividends paid per common share	\$1.14	\$0.96	\$0.88
Dividends paid per preferred share	\$1.69	\$1.69	\$1.69

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

\*\* Operating margin is not a recognized measure under Canadian GAAP and does not have a standardized meaning prescribed by Canadian GAAP. See “Non-GAAP Measures”.

## Results of Operations

The following table summarizes the Company's revenues and operating results by business segment.

*[\$ in thousands]*

	<b>Gas Transmission and Distribution</b>	<b>Renewable Energy</b>	<b>Total</b>
<b>Year ended December 31, 2010</b>			
Revenues	\$ 93,848	\$ 1,316	\$ 95,164
Operating margin	\$ 49,735	\$ 1,316	\$ 51,051
Net income (loss) attributable to shareholders	\$ 7,640	\$ (552)	\$ 7,088
<b>Year ended December 31, 2009</b>			
Revenues	\$104,131	\$ —	\$104,131
Operating margin	\$ 46,892	\$ —	\$ 46,892
Net income attributable to shareholders	\$ 6,532	\$ —	\$ 6,532

### Gas Transmission and Distribution

Revenues in 2010 were \$93.8 million compared with \$104.1 million in 2009. Gas sales to residential and commercial customers were down by \$13 million in 2010 compared to 2009, primarily due to the effects on revenues of warmer weather and a lower commodity cost of gas during 2010. 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. The decrease in 2010 gas sales revenues was partially offset by the positive impacts of the CAP/ROE Application settlement which provided for both a higher ROE and higher equity components.

Operating margin in 2010 increased to \$49.7 million, as compared with \$46.9 million in 2009. The increase of \$2.8 million was mainly due to the higher weighted-average allowed return on deemed common equity of 10.09 percent in 2010 compared to 9.58 percent in 2009 and the recognition of the 5 percent increase in the equity component for the Company's Western system effective January 1, 2009. This was partially offset by lower than anticipated deliveries to large commercial customers and lower than anticipated net customer additions in 2010.

### Renewable Energy

For the period from the acquisition date to December 31, 2010, the McNair hydro-electric facility generated revenues of \$1.3 million. Operating costs for this period amounted to \$0.18 million. The Company recorded net earnings before acquisition and reorganization costs of approximately \$0.15 million from renewable energy operations. Transaction costs amounted to approximately \$0.7 million after-tax for the nine month period ended

December 31, 2010. As noted in the “Summary of Quarterly Results”, production from the McNair facility is seasonal.

During 2010, the McNair Creek facility experienced above-average hydrologic conditions due to a higher than normal snowpack, cooler temperatures in the second quarter and above-average precipitation in the fourth quarter. As a result, from the acquisition date to December 31, 2010, electricity generation from the McNair Creek facility was higher than the estimated long-term average.

## Natural Gas Deliveries

A comparison of natural gas deliveries for the years 2010 and 2009 is provided in the following table:

*[Deliveries in TJ]*

	<b>2010</b>	<b>2009</b>
<b>Sales:</b>		
Residential	<b>2 858</b>	3 221
Commercial	<b>2 430</b>	2 851
Small Industrial	<b>400</b>	471
Large Industrial	<b>7</b>	187
<b>Total Sales</b>	<b>5 695</b>	6 730
<b>Transportation Service:</b>		
Commercial	<b>274</b>	230
Small Industrial	<b>2 347</b>	2 595
Large Industrial	<b>1 171</b>	2 590
<b>Total Transportation Service</b>	<b>3 792</b>	5 415
<b>Total Deliveries</b>	<b>9 487</b>	12 145

Deliveries to residential and commercial customers in 2010 were lower by 784 TJ, or 13 percent, compared to deliveries in 2009 due primarily to the warmer weather in 2010 compared to 2009. Weather was warmer by 8 percent compared to prior year and 3 percent warmer than normal. These deliveries were lower than the forecast used for rate making purposes but this did not significantly impact net income due to the existence of the rate stabilization adjustment mechanism (“RSAM”) deferral account that captured the after-tax value of the revenue variance, amounting to \$2.1 million in 2010. In 2009, deliveries were higher than forecast due to colder weather and resulted in an after-tax value revenue variance of \$0.97 million recorded as a credit to the RSAM deferral account.

## Industrial Customers

Deliveries to small industrial customers decreased by 319 TJ in 2010 compared to 2009 primarily due to lower consumption by small industrial customers in the forestry sector.

The Company has a firm transportation service and interruptible sales/service agreements with Rio Tinto Alcan Inc. (“Alcan”) effective through October 31, 2012. The agreement

with Alcan will continue to be in effect beyond October 31, 2012 unless Alcan or the Company gives notice of termination. During 2010, deliveries to Alcan accounted for 9.1 percent of the Company's total gas deliveries and 2.7 percent of revenues.

Alcan produces a commodity that is subject to price fluctuations. The Company's gas deliveries to Alcan have been and may in the future be affected by their ability to continue operations during sustained periods of low prices. Alcan's gas consumption in 2010 was lower by 59 TJ, or 6.3 percent, compared to 2009.

West Fraser permanently closed its Kitimat mill at the end of January 2010 and terminated its agreement with the Company by providing six months notice and making a termination payment to the Company of \$5.1 million on December 1, 2010. Deliveries to West Fraser in the months of January and February of 2010 accounted for 2.5 percent of the Company's total gas deliveries and 2.2 percent of total revenues.

The Company delivers gas to its other large industrial customer, BC Hydro, under an interruptible sales/service agreement for emergency electric power generation at BC Hydro's facility in Prince Rupert. Deliveries to BC Hydro in 2010 amounted to 71 TJ compared to 14 TJ in 2009. In both years, BC Hydro operated its station on an intermittent basis to ensure the station was in a ready to operate mode in case of an emergency. However, the higher deliveries in 2010 compared to 2009 were due to BC Hydro operating the facility at the request of the Company to facilitate the use of an in-line pipeline inspection tool.

### **Customer Additions**

There was a net increase of 292 to the ending number of customers in 2010 as the Northeast system service area experienced a net gain of 479 customers and the Western system service area experienced a net loss of 187 customers.

There are few remaining candidates for conversion to natural gas in the existing building stock and limited opportunity remains to extend gas mains into unserved rural areas in the Western system service area. The Company added approximately 100 new customers in 2010 in the community of Tomslake, B.C., in the Dawson Creek division as it finalizes the new gas distribution system in this rural area and also added an additional 69 new service installations in this area. The Company did expect to see some customer losses in Kitimat and surrounding areas due to the closure of West Fraser's Kitimat paper mill.

### **Natural Gas Supply**

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

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

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

For 2010, approximately 42 percent of gas purchases were hedged pursuant to the Company's gas price management plan (for further information as of December 31, 2010 see "Financial Instruments and Other Instruments").

A gas supply contracting plan is prepared annually and filed with the Commission for review prior to finalizing annual gas purchase arrangements. The gas contracting plan is designed to ensure the Company has adequate gas supplies to meet the requirements of its customers on the coldest day of the year, normally referred to as "the peak day". Contracted gas that is surplus to customer requirements on any particular day is sold into other markets at prevailing market prices through off-system gas sales. Most of the Company's contracted gas supply is produced in British Columbia.

Most of the Company's gas supply is comprised of the pooled gas stream available from the Spectra Energy transmission pipeline system. This includes all of the supply to the Company's transmission line serving its Western system service area and, during 2010, approximately 76 percent of the supply for the Fort St. John and Dawson Creek service areas.

In addition to the supply from the Spectra Energy system, the Fort St. John system incorporates two interconnections with Canadian Natural Resources Limited's West Stoddart pipeline, providing 34 percent of the Fort St. John system's requirements in 2010. In Dawson Creek, approximately 5 percent of the required 2010 supply was received from a local producer of sweet (pipeline quality) gas at a point where its system intersects the Company's transmission line. In Tumbler Ridge, all of the gas supply is obtained in the form of raw gas production from Canadian Natural Resources Limited and the Company operates its own gas processing facilities.

In 2010, gas was purchased under a number of short term seasonal, base load and spot gas supply arrangements. Short term gas supply contracts are in keeping with current industry practices.

## **Regulatory Activities**

The Company's natural gas sales and delivery services are subject to regulation under the Utilities Commission Act of British Columbia. The Commission regulates these business activities, including the construction and operation of major facilities, the issuance of securities, the determination of rates for the sale and transportation of gas, and the terms and conditions of service.

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

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

Revenue requirements applications for all service areas are submitted to the Commission, generally on an annual basis. The Commission may consider these applications through a public hearing process (either oral or written), or through Commission staff supervised negotiations between the Company and its customers under negotiated settlement guidelines issued by the Commission. Settlements are subject to final approval by the Commission.

### **2011 Revenue Requirements Applications**

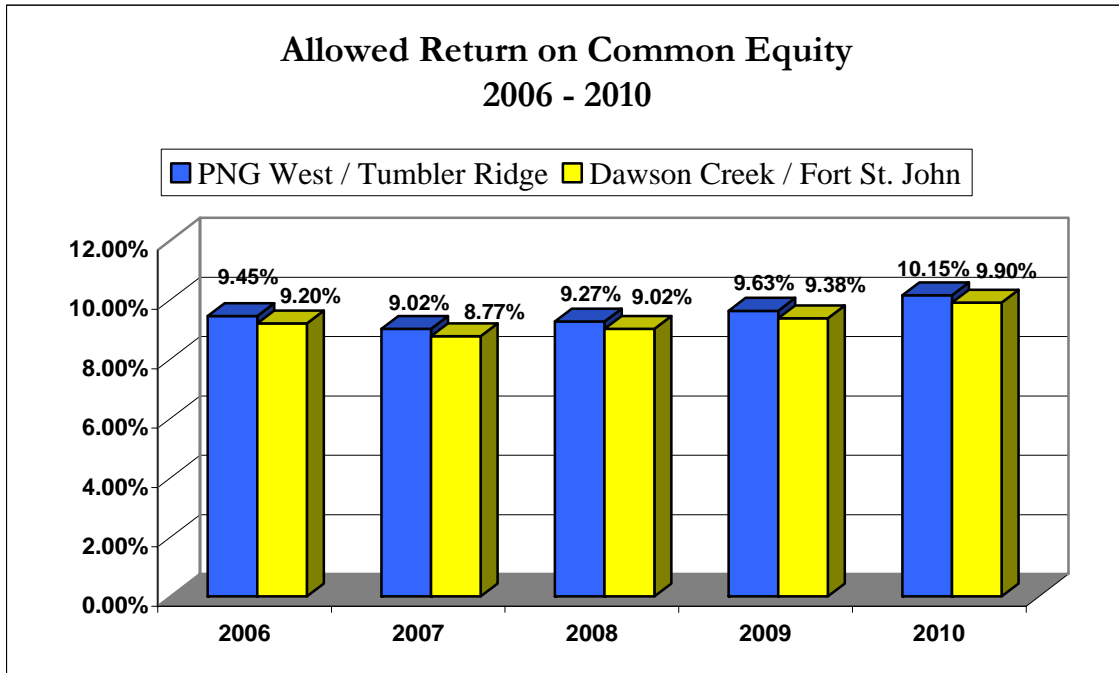
In late November 2010, the Company filed its 2011 revenue requirements applications for all divisions. The applications sought approval to increase rates on an interim basis effective January 1, 2011 pending the Commission's review of the applications. The Commission approved interim rates effective January 1, 2011 at the levels set forth in the applications.

The Company amended the applications in mid-January 2011 to reflect changes to the treatment of a number of deferral accounts in response to being advised that the Commission had directed other utilities to reflect changes in response to the deferred implementation of IFRS for rate-regulated entities effective January 1, 2012, rather than January 1, 2011 (see "Changes in Accounting Policies – Future Accounting Pronouncements"). The 2011 revenue deficiency projected for the Western system under the amended application is approximately \$2.7 million.

PNG (N.E.)'s Fort St. John/Dawson Creek division has a forecast 2011 revenue deficiency of close to \$2.4 million while the Tumbler Ridge division forecast revenue deficiency for 2011 is negligible. The applied for delivery charge increases compared to October 2010

delivery rates for an average residential customer in each service area are 8.3 percent for the Western system (\$72 per year), 25.4 percent for the Fort St. John/Dawson Creek division (\$93 per year) and 0.5 percent for the Tumbler Ridge division (\$2 per year).

A negotiated settlement process is expected to be conducted with respect to the 2011 revenue requirements applications in the second quarter of 2011.



## 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>	<b>2010</b>			
	<b>Mar. 31</b>	<b>June 30</b>	<b>Sept. 30</b>	<b>Dec. 31</b>
Revenues	<b>\$40,235</b>	<b>\$15,166</b>	<b>\$9,682</b>	<b>\$30,081</b>
Net income (loss) attributable to shareholders	<b>\$5,488</b>	<b>\$(146)</b>	<b>\$(2,238)</b>	<b>\$3,984</b>
Earnings (loss) per common share – basic	<b>\$1.51</b>	<b>\$(0.06)</b>	<b>\$(0.64)</b>	<b>\$1.10</b>
Earnings (loss) per common share – diluted	<b>\$1.48</b>	<b>\$(0.06)</b>	<b>\$(0.64)</b>	<b>\$1.06</b>
	<b>2009</b>			
	<b>Mar. 31</b>	<b>June 30</b>	<b>Sept. 30</b>	<b>Dec. 31</b>
Revenues	\$48,318	\$14,141	\$10,500	\$31,172
Net income (loss) attributable to shareholders	\$5,156	(\$400)	(\$1,660)	\$3,436
Earnings (loss) per common share – basic	\$1.39	(\$0.13)	(\$0.49)	\$0.95
Earnings (loss) per common share – diluted	\$1.38	(\$0.13)	(\$0.49)	\$0.93

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***

Cash and cash equivalents at December 31, 2010 of \$1.9 million were \$0.4 million higher than at December 31, 2009. Accounts receivable at December 31, 2010 of \$23.0 million were \$1.4 million higher than at December 31, 2009 even though deliveries to customers were lower in 2010 compared to 2009. The increase in accounts receivable is mainly due to the higher delivery rates in 2010, the timing of customer payments, and the inclusion of a receivable from BC Hydro for the McNair operations at the end of 2010. Prepaid expenses of \$1.1 million at December 31, 2010 remained at levels similar to those at the end of the prior year.

Accounts payable and accrued liabilities of \$19.1 million at December 31, 2010 were lower by \$2.5 million compared to December 31, 2009, mainly due to lower gas purchase costs in December 2010 as a result of lower gas commodity prices. At December 31, 2010, there is a \$1.3 million income tax recoverable balance compared to an income tax payable amount of \$1.0 million at December 31, 2009. This is mainly due to tax-deductible rate rider credits refunded to customers from the gas purchase variance account during 2010 and the recognition of non-taxable revenues through the RSAM account due to the warmer temperatures in 2010. Other taxes payable at December 31, 2010 remained at similar levels as at December 31, 2009.

The gas purchase variance recoverable account has increased by \$3.3 million resulting in a net recoverable amount of \$4.5 million at December 31, 2010, compared to the net recoverable balance of \$1.2 million at December 31, 2009. This increase 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 increased to a net liability position of \$6.1 million at December 31, 2010, up \$2.2 million from \$4.0 million at December 31, 2009 due to decreasing market commodity prices; the gas purchase variance account increased by \$2.4 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 \$1.2 million.

Following a December 31, 2009 actuarial valuation of the Company's pension plan completed in September 2010, the Company made funding contributions in 2010 to its pension plan of \$2.4 million (\$1.3 million in 2009) and expects similar contributions will be required in 2011 and onwards. The Company does not expect this to have a material impact on the Company's liquidity.

## Contractual Obligations

*[\$ in thousands]*

	<b>Payments Due by Period as of December 31, 2010</b>				
	<b>Total</b>	<b>Less than 1 year</b>	<b>1 - 3 years</b>	<b>4 - 5 years</b>	<b>After 5 years</b>
Bank indebtedness	\$ 4,836	\$ 4,836	\$ —	\$ —	\$ —
Accounts payable and accrued liabilities	19,106	19,106	—	—	—
Long-term debt (principal repayments)	91,567	8,192	6,476	23,416	53,483
Derivative financial liabilities	6,172	5,696	476	—	—
Purchase obligations	24,878	19,837	4,893	52	96
<b>Total contractual obligations</b>	<b>\$146,559</b>	<b>\$ 57,667</b>	<b>\$ 11,845</b>	<b>\$ 23,468</b>	<b>\$ 53,579</b>

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

### **Funding Requirements**

The Company's capital expenditures, acquisition costs, working capital needs, dividend payments and debt repayments are funded from a combination of sources. During 2010, the primary sources of funding were \$9.9 million of net cash provided by operating activities and a \$10.0 million draw on the Company's 5-year revolving term facility.

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

### **Financial Ratios**

For the year ending December 31, 2010, interest coverage using earnings before interest, income taxes, depreciation, and amortization was 3.77 times compared to 4.00 times in the prior year.

## Funding Costs

### Interest expense

*[\$ in thousands]*

	2010	2009
Long-term interest expense	\$6,100	\$5,653
Short-term interest expense	102	81
Imputed interest on regulatory accounts	202	(91)
Total	\$6,404	\$5,643
Effective blended cost of debt	6.7%	7.3%

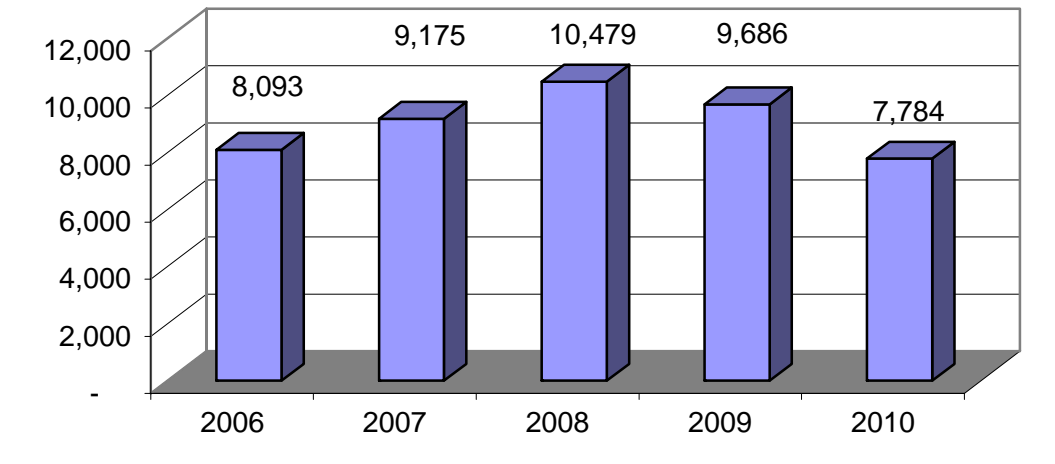
The decrease in the effective blended cost of debt in 2010 relative to 2009 is due mainly to the changing mix of debt instruments in the Company's portfolio. In particular, the fixed-rate debentures issued by the Company continue to amortize and are becoming a smaller portion of the Company's debt portfolio while lower-cost floating-rate debt is becoming an increasing portion of the portfolio.

## Capital Expenditures

Total capital expenditures of \$7.8 million in 2010 were 20 percent or \$1.9 million lower than those incurred in 2009, and 14 percent below the average level of expenditures for the last five years. This decrease primarily resulted from the need to defer the rehabilitation of a tunnel through which one of the Company's pipelines runs, as access to the construction site was not possible due to lower than normal water levels in the Skeena River.

Expenditures incurred in 2010 related primarily to scheduled capital projects necessary to ensure the ongoing integrity of the Company's transmission system. During 2010, the Company completed the installation of the new rural gas distribution system in the Tomslake area south of Dawson Creek. The Tomslake work commenced in 2009 with the installation of approximately 97,000 metres of main, and concluded in 2010 with the installation of an additional 33,000 meters of main. The Company also completed 543 new distribution service line installations in 2010, compared with 261 installations in 2009. Most of these new service lines were installed in the Northeast system, reflecting continued strong economic activity in this area.

**Capital Expenditures (\$000's)  
2006 - 2010**



**Capital Expenditures**  
*[\$ in thousands]*

	<b>2010</b>	<b>2009</b>
Transmission system	<b>\$1,714</b>	\$4,470
Distribution system	<b>4,545</b>	4,049
Processing plant	<b>273</b>	1,010
Other	<b>1,252</b>	157
<b>Total</b>	<b>\$7,784</b>	\$9,686

Planned capital spending for 2011 is forecast to be approximately \$7.6 million and is primarily focused on installation of distribution mains and services in the Northeast system as well as transmission mainline rehabilitation in the Western system. 2011 planned capital activities also include the tunnel rehabilitation deferred in 2010. Contractual commitments have yet to be 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.

## Capital Resources

### Composition of Capital Structure

<i>[Percent]</i>	<b>December 31, 2010</b>	<b>December 31, 2009</b>
Preferred shareholders' equity	<b>2.6</b>	3.0
Common shareholders' equity	<b>46.9</b>	51.0
Short-term debt	<b>2.6</b>	1.5
Long-term debt, including current portion	<b>47.9</b>	44.5
	<b>100.0</b>	100.0

For rate determination purposes, the Company is permitted to earn a return on its invested capital to the extent of its approved rate base. Rate base is composed of the depreciated book value of plant, property and equipment, plus unamortized deferred charges, plus an allowance for working capital, less deferred income taxes. The Commission sets customer rates at a level that is intended to allow the Company to earn its allowed rate of return on common equity. Rates for 2010 were based on 40 percent of rate base being financed by common equity for the Fort St. John/Dawson Creek and Tumbler Ridge divisions and 45 percent for the Western system.

### Equity

The book value of the Company's common shares at December 31, 2010 was \$24.63 per share, compared to \$24.03 per share at December 31, 2009.

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

### Dividends

Preferred dividends totaling \$1.6875 per preferred share were paid in 2010, the same as in 2009. Common dividends totaling \$1.14 per common share were paid in 2010, compared to \$0.96 per common share in 2009. Total dividend payments in 2010 for both preferred and common shares were \$4.4 million, compared to payment of \$3.8 million in 2009.

### Credit Facilities

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.

The first risk management facility has a single financial covenant requiring the Company's debt leverage not to exceed 65 percent. The Company added a second risk management facility in January 2010. This facility 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 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 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. Under either facility, to the extent the credit exposure of the facility provider exceeds \$20 million (where exposure is calculated by the facility provider using its standard methodology), the Company is required to provide cash collateral for the exposure in excess of \$20 million. Neither hedge facility provider is obligated to enter into any transactions with the Company under the terms of the facilities. Each hedge transaction must be agreed between the parties. The provider of one of the risk management facilities has documented its intention not to enter into transactions under its facility in the event that the provider's exposure would exceed \$15 million.

### **Short-term Debt**

In November 2010, the Company completed a renegotiation and extension of its bank operating facility. Under this facility, \$25.0 million is available for working capital purposes. The November 2010 amendments included deletion of the previous borrowing base limitation to availability under the operating facility. As a result, the \$25.0 million is available to the Company at all times subject to a requirement that borrowings be reduced to zero for 30 days each calendar year. The Company covenants under the facility to maintain its debt leverage at 65% or less. At December 31, 2010 the Company's actual debt leverage was 50.4 percent. The operating line is collateralized by a pledge of the Company's accounts receivables and inventories.

Borrowings under the operating facility bear interest at prime rate or bankers' acceptance rates plus an applicable credit spread. The renegotiated terms included reduced credit spreads to 1 percent over prime and 2.25 percent over bankers' acceptances, previously 1.5 percent and 3 percent respectively, as well as a reduction in the stand-by fee to 0.35 percent from 0.5 percent. The renewed 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 December 31, 2010, the actual utilization of the operating line was \$8.6 million.

### **Long-term Debt**

On February 2, 2010 the Company amended its revolving term facility to increase the amount available under the facility to \$35 million (previously \$20 million) and to extend its maturity date to January 30, 2015. Concurrent with these amendments, the fees and interest rate spreads under the facility were amended to reflect current market conditions.

The standby fee on the facility was increased to 50 basis points on undrawn amounts and the interest rate spread over the Canadian Dealer Offered Rate (“CDOR”) was increased to 307.5 basis points from 132.5 basis points. The facility contains a financial covenant requiring the Company’s debt leverage not to exceed 65 percent and, 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 maximum of \$10 million.

\$16.0 million was outstanding under the revolving term facility at December 31, 2010 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.

On May 17, 2010, DBRS confirmed the Company’s secured debt ratings at BBB (low).

### ***Off-Balance Sheet Arrangements***

As of December 31, 2010, the Company had no off-balance sheet arrangements.

### ***Transactions with Related Parties***

The Company had no significant transactions with related parties during 2010 or 2009.

## Fourth Quarter 2010

The following table compares the results for the fourth quarters of 2010 and 2009:

*[\$ in thousands, except TJ, customer, per GJ and per share figures]*

	<b>Q4 2010</b>	<b>Q4 2009</b>	<b>Percent Change</b>
Deliveries (TJ)			
Sales	<b>2 127</b>	2 334	(8.9)
Transportation service	<b>1 040</b>	1 514	(31.3)
Total deliveries	<b>3 167</b>	3 848	(17.7)
Customers at period end	<b>39,405</b>	39,113	0.8
Weighted average cost of gas purchased (\$ per GJ)	<b>\$4.85</b>	\$6.35	(23.6)
Revenues	<b>\$30,081</b>	\$31,172	(3.5)
Operating margin, consisting of revenues less cost of gas	<b>\$16,024</b>	\$13,916	15.1
Income before income taxes	<b>\$5,098</b>	\$4,446	14.7
Net income attributable to shareholders	<b>\$3,984</b>	\$3,436	16.0
Net cash provided by operating activities	<b>\$5,480</b>	\$2,074	158
Basic earnings per common share	<b>\$1.10</b>	\$0.95	15.7
Dividends paid per common share	<b>\$0.30</b>	\$0.25	20.0

Revenues in the fourth quarter of 2010 decreased to \$30.1 million as compared with \$31.2 million in the same period in 2009. The decrease in revenues is mainly due to a \$1.4 million decrease in off system gas sales in the fourth quarter of 2010 compared to the fourth quarter of 2009, offset by new revenues from the McNair operations in 2010.

Operating margin in the fourth quarter of 2010 increased to \$16.0 million from \$13.9 million in the corresponding period in 2009. This increase can be attributed to the higher common equity component in 2010 compared to 2009, new revenues from the 2010 McNair acquisition and the higher delivery rates in 2010 compared to 2009 mainly to recover the loss of the Methanex termination payment credit amortization which ended in October 2009.

Net income for the quarter ended December 31, 2010 was \$4.0 million, compared with \$3.4 million for the quarter ended December 31, 2009. Included in the results for the fourth quarter of 2010 are reorganization charges, net of income taxes, totaling \$0.1 million or \$0.03 per share relating to the Company's restructuring of the McNair

acquisition group of companies, compared to the inclusion of the Company's share of KSL Project after-tax development expenses of \$0.04 million or \$0.01 per share in the corresponding period in 2009.

After providing for preferred share dividends, earnings per common share in the fourth quarter of 2010 were \$1.10, compared with \$0.95 for the quarter ended December 31, 2009.

Capital expenditures in the fourth quarter of 2010 were \$2.9 million, compared to \$4.2 million in the comparable period in 2009.

### ***Subsequent Event***

On February 7, 2011, the Company announced it had entered into an agreement to sell its 50 percent interest in PTP to Apache Canada and EOG Canada, the Company's partners in the KSL Project, for payments of up to \$50 million. The transaction closed on March 2, 2011.

The sale transaction has two elements, including an initial payment of \$30 million paid on closing and a second payment of \$20 million to be paid contingent on the purchasers making a decision to proceed with construction of the Kitimat LNG facility. The Company can give no assurances that construction of the Kitimat LNG facility will be completed or that the \$20 million payment will be made.

In connection with the sale, the Company has reached agreement on the terms for a 20-year transportation service agreement with Apache Canada and EOG Canada that will significantly increase the utilization of the Company's current pipeline in the event that LNG Partners does not claim this capacity first. The Company will operate the KSL Project pipeline under an operating and maintenance agreement negotiated with Apache Canada and EOG Canada. The operating and maintenance agreement will have an initial term of seven years beginning in 2015, with renewal provisions, and will be subject to approval by the Commission. These agreements are expected to generate incremental revenue for the Company, with substantial benefits flowing back to the Company's customers in the form of reduced gas delivery rates, with rate reductions similar to those that would have prevailed had the Company continued to own a 50 percent stake in PTP.

## ***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.

## **Regulatory Assets and Liabilities**

Certain regulatory assets represent future revenues associated with certain costs, incurred in the current period or in prior periods that are expected to be recovered from customers in future periods through the rate-setting process. Regulatory liabilities represent future reductions or limitations of increases in revenues associated with amounts that are expected to be refunded to customers as a result of the rate-setting process. In the absence of rate regulated accounting, generally accepted accounting principles would not likely permit recognition of regulatory assets and certain liabilities and therefore the earnings impact would be recorded in the period incurred or recovered. These regulatory assets and liabilities have been recorded based on previous, existing or expected regulatory orders or decisions. Certain estimates are necessary since amounts recorded are often estimates until these amounts are finalized pursuant to regulatory decisions or proceedings.

## **Depreciation of Plant, Property and Equipment**

The Company depreciates plant, property and equipment on a straight-line basis over the estimated useful life of the assets. The estimated useful lives are largely based on formal depreciation studies and are approved by the Commission. Changes in estimates can have a significant impact on depreciation expense.

## **Unbilled Revenues**

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. These estimates are made assuming normal consumption patterns, which may differ from actual consumption patterns. The estimates of unbilled operating revenue comprise 10.6 percent of the Company's revenues for 2010. Through future meter readings, the usage estimates are replaced with actual delivered volumes, which become reflected in the Company's financial results at that time.

## **Asset Retirement Obligations ("AROs")**

The Company is required to recognize the fair value of asset retirement obligations associated with the retirement of long-lived assets in the period which they can be reasonably determined. The Company's natural gas transmission and distribution long-lived assets are comprised principally of mains, service lines, compressors, and measuring and regulating equipment. No amount has been recorded for AROs relating to the Company's assets as it is not possible to make a reasonable estimate of the fair value

of the liability due to the indeterminate timing and scope of the asset retirements. Management expects that all retirement costs associated with the regulated assets will be recovered through tolls in future periods.

## **Employee Future Benefit Plans**

The Company provides a defined benefit pension plan and other post retirement benefits to the majority of its employees. The determination of these expenses and obligations is dependent on management's assumptions including the discount rate for the accrued benefit obligation and the expected long-term rate of return on plan assets.

The assumed discount rate to determine the Company's accrued pension and non-pension benefit obligations at December 31, 2010 was 5.3 percent and is based on the market interest rates as of September 30, 2010 for high-quality corporate bonds. The comparative discount rate as at December 31, 2009 was 6.5 percent.

The assumed long-term rate of return on the defined benefit pension plan assets for the purposes of estimating pension expense for both 2010 and 2009 was 7.0 percent. The pension plan assets are comprised primarily of equity and fixed income investments. Fluctuations in actual market returns and changes in interest rates may result in increases or decreases to future pension expenses.

## ***Changes in Accounting Policies***

### **Changes Applicable in 2010**

#### **Business combinations, consolidated financial statements and non-controlling interests**

Effective January 1, 2010, the Company early adopted the pronouncements of CICA Handbook Section 1582, Business Combinations, Section 1601, Consolidated Financial Statements, and Section 1602, Non-Controlling Interests.

Section 1582 was introduced to replace Section 1581, Business Combinations, and provides the Canadian equivalent to International Financial Reporting Standard IFRS 3 (revised), Business Combinations. Section 1582 specifies a number of changes, including: an expanded definition of a business, a requirement to measure all business acquisitions at fair value, a requirement to measure non-controlling interests at fair value, and a requirement to recognize acquisition related costs as expenditures in the period incurred.

Section 1601 and Section 1602 were introduced together to replace Section 1600, Consolidated Financial Statements, and provide the Canadian equivalent to the corresponding provisions of International Accounting Standard IAS 27 (revised), Consolidated and Separate Financial Statements. Section 1601 establishes standards for the preparation of consolidated financial statements and Section 1602 specifies that non-

controlling interests be treated as a separate component of equity, instead of a liability or other item outside of equity.

The early adoption of these standards by the Company resulted in additional disclosure related to a business acquisition that closed on April 19, 2010 and the expensing of the related acquisition costs incurred of \$0.5 million, rather than their inclusion as part of the cost of the business acquisition.

## **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 International Financial Reporting Standards for years beginning on or after January 1, 2011. The transition to IFRS will require the restatement for comparative purposes of amounts reported for the year prior to the transition date.

### **Recent Developments**

In September 2010, the International Accounting Standards Board (“IASB”) concluded that it could not quickly resolve the matters arising from its rate-regulated activities (“RRA”) Exposure Draft and the resulting subsequent discussions. In 2011, the IASB will be considering the development of an agenda proposal on this issue for consideration on its future projects agenda. 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.

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**

As previously disclosed, the Company originally planned to begin reporting under IFRS effective January 1, 2011, and the Company’s IFRS conversion plan was proceeding as planned to this conversion date. Given the recent decision to defer adoption of IFRS for one year, the Company’s IFRS plan has been amended as following:

#### ***IFRS 1, First-Time Adoption of IFRS***

Previously, the adjustments required under IFRS 1 were evaluated in anticipation of a January 1, 2010 transition. Due to the one-year deferral, these first-time adjustments will now be evaluated and determined to be effective for the opening IFRS balance sheet as at January 1, 2011.

- *Employee Benefits*  
The Company will elect to recognize all cumulative actuarial gains and losses and all unamortized transitional obligations of defined benefit plans through opening

retained earnings at January 1, 2011. The amount of this adjustment will be determined in the first quarter of 2011.

- *Property, Plant and Equipment and Intangible Assets*  
In April 2010, the IASB approved an IFRS 1 exemption which allows the Company 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. The amount of this adjustment will be determined in the first quarter of 2011.

#### ***Rate-regulated activities***

The Company, in accordance with Canadian GAAP, follows specific accounting policies unique to a rate-regulated entity. These accounting policies for rate-regulated activities are pervasive and significant to the Company's business model and performance measurement.

As noted above, there is no separate IFRS standard for RRA and the current interpretation of existing IFRS guidance generally does not allow accounting for RRA in the manner historically permitted under Canadian GAAP. The Company will continue to monitor both developments in IFRS and decisions made by other rate-regulated entities.

The Company has amended its IFRS conversion plan to include an assessment of changes required if accounting for RRA is no longer available under IFRS, including:

- Determination of the adjustment required upon derecognition of regulatory assets and regulatory liabilities effective January 1, 2011;
- Determination of the impact on debt covenants if accounting for RRA is no longer available under IFRS; and
- Development of a communication plan to internal and external stakeholders.

However, for rate-setting purposes, the Company will continue to make use of deferral accounts. Therefore, the Company plans to maintain two sets of accounts and will be assessing the processes and resources required to maintain two sets of accounting records.

#### ***Property, plant and equipment***

The Company is currently developing accounting policies that will be IFRS compliant. These policies will differ from the Company's current accounting policies and are expected to be finalized during the first half of 2011.

#### ***Employee future benefit plans***

The Company is continuing with its assessment of policy choices available under the current IFRS standard for employee future benefits and is monitoring the ongoing developments related to this standard.

### ***Presentation and disclosure***

The Company completed the initial preparation and review of pro forma annual IFRS financial statements, identifying changes to presentation and additional disclosures required under IFRS. The pro forma financial statements had included regulatory assets and regulatory liabilities. The Company is in the process of updating the pro forma statements to eliminate these balances and the effects of the underlying transactions.

### ***Derivative financial instruments***

The Company currently records the fair value of a fixed-price natural gas supply contract at each reporting date and includes this amount in the fair value of its derivative financial instruments. Under IFRS, the Company's fixed-price natural gas supply contract is a contract to buy or sell a non-financial item in accordance with the Company's expected purchase, sale or usage and qualifies for a scope exemption from being recognized as a financial instrument at fair value. Accordingly, for the opening IFRS balance sheet as at January 1, 2011, the application of this exemption will result in a \$0.7 million decrease in derivative financial instrument liability.

In addition to planning for the deferred 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 IASB exposure drafts and to assess potential impacts of new IFRS that may be applicable as at the January 1, 2011 transition date.

The Company is satisfied that its transition plans are on schedule and will be providing further updates on the status of key activities in the Company's 2011 interim Management's Discussion and Analysis.

### **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 is not expected to have a material impact on the Company's 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 is not expected to have a material impact on the Company's 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 with 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 Company is currently assessing the impact of adopting EIC-175 on its financial statements.

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

**As at December 31, 2010**

<b>Financial instrument</b>	<b>Notional quantity</b> (gigajoules)	<b>Percent of annual gas purchases</b> (%)	<b>Delivery period</b>	<b>Price range</b> (per gigajoule)	<b>Estimated net fair value receivable (payable)</b> ((\$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)
	<b>4 800 100</b>	<b>50.2</b>			<b>(6,139)</b>

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.

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, 2009, the Company had outstanding fixed-price, natural gas swap and collar contracts relating to natural gas supply as follows:

**As at December 31, 2009**

<b>Financial instrument</b>	<b>Notional quantity</b> (gigajoules)	<b>Percent of annual gas purchases</b> (%)	<b>Delivery period</b>	<b>Price range</b> (per gigajoule)	<b>Estimated net fair value receivable (payable)</b> ((\$000's))
Fixed-price contracts	900 000	9.2	Jan 2010 – Mar 2010	\$4.03	1,021
Natural gas swap contracts	3 954 850	40.6	Jan 2010 – Oct 2011	\$4.96 to \$10.87	(4,568)
Collar contracts	308 650	3.2	Jan 2010 – Oct 2010	\$5.26 to \$8.38 (floors) \$6.76 to \$11.46 (caps)	(429)
	<b>5 163 500</b>	<b>53.0</b>			<b>(3,976)</b>

The fair value reflects the estimated amounts that the Company would receive or pay at December 31, 2009 to terminate the fixed price, natural gas swap and collar contracts based on the estimated net cash flows under the terms of each contract.

Natural gas prices for 2011, based on forward gas prices as at March 2, 2011 and forecast gas purchases by the Company in 2011, are forecast to be approximately 15.6 percent (\$0.82 per GJ) lower than the actual corresponding prices in 2010.

## ***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.

Management, under the supervision of the Chief Executive Officer and Vice President, Finance, acting as the Chief Financial Officer, have evaluated the effectiveness of the Company's DC&P and ICFR and based on that evaluation have concluded that DC&P and ICFR were effective as at December 31, 2010.

There have been no changes in the Company's ICFR during the year ended December 31, 2010 which have materially affected, or are reasonably likely to materially affect, ICFR.

The Chief Executive Officer and Vice President, Finance, acting as the Chief Financial Officer, have limited the scope of their certification in accordance with National Instrument 52-109 for the design and effectiveness of DC&P and ICFR to exclude controls, policies and procedures resulting from the acquisition of McNair on April 19, 2010. The business acquired is described under "Business of the Company – Renewable Energy Business". The Company's financial results for the year ended December 31, 2010 include revenues of \$1.3 million and a net loss of \$0.55 million, and its consolidated balance sheet includes \$21.2 million in assets and \$12.4 million in liabilities as at December 31, 2010 related to McNair.

With respect to the acquisition of McNair, where the scope of the Chief Executive Officer and Vice President, Finance, acting as the Chief Financial Officer, has been limited in accordance with National Instrument 52-109, the Company's management, under the supervision of the Chief Executive Officer and Vice President, Finance, acting as the Chief Financial Officer, has evaluated the overall risk, reviewed the results of operations with operating management and confirmed that consistent controls have operated since the Company's acquisition of McNair and continued to operate at year end. Management is confident in the reliability of financial reporting and the preparation of financial statements included in the Company's consolidated results. In 2011, the Company will certify that the internal controls over financial reporting and the disclosure controls and procedures for McNair are designed and effective under National Instrument 52-109.

## ***Outstanding Share Data***

At March 2, 2011 there were 200,000 preferred shares and 3,615,144 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.

## ***Risk Factors***

### **Usage Risk and Impact of Changes in Economic Conditions**

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

Over the past several years the average amount of natural gas consumed by residential customers has declined. This decline is attributable to a number of factors, including the replacement of older heating equipment by newer, more efficient equipment, more energy efficient housing, and energy conservation measures in response to higher gas prices and poor economic conditions in the Western system region.

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

### **Industrial Customer Concentration and Potential for Termination of Large Industrial Contracts**

In 2010, 12 percent of energy deliveries were made to the Company's three largest industrial customers, compared to 23 percent in 2009. West Fraser ceased operations at its Kitimat mill in January 2010 and provided a contract termination notice to the

Company in May 2010 which resulted in a \$5.1 million termination payment received on December 1, 2010. Deliveries to West Fraser accounted for approximately 2.5 percent of annual deliveries in 2010 compared to 15.1% in 2009. Lower demand and lower prices for forest products in North America resulted in the lower deliveries to the forest sector again in 2010. The forest sector has been facing significant issues with low lumber prices, the mountain pine beetle infestation and the strength of the Canadian dollar in 2010. Management can give no assurances that these issues will be resolved.

The initial term of the Company's agreement with Rio Tinto Alcan ended November 1, 2004, but the agreement automatically continues in effect from contract year to contract year unless either party gives twelve months' notice of termination. No termination notice has been given. During 2010, deliveries to Rio Tinto Alcan accounted for 9.1 percent of the Company's total gas deliveries and 2.8 percent of revenues.

The Company's ability to negotiate new contracts and to renegotiate existing contracts could be impacted by factors it cannot control, including reduced demand due to higher gas prices, the financial strength of major customers and the availability and price competitiveness of alternative energy sources. The risk of non-performance by one or more of the large industrial customers may be analyzed and managed, but it cannot be entirely eliminated.

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

### **Commodity Price and Supply Risk**

The commodity cost of natural gas can be highly volatile. The Company's average cost of natural gas in 2010 was approximately 14.3 percent lower than in 2009 and 30.6 percent lower than in 2008. When prices are low, the prospects of fuel-switching and increased energy conservation pose a lesser risk. Fluctuations in the price of natural gas may increase the Company's working capital financing requirements and related costs for accounts receivable, and may give rise to higher bad debt costs.

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

## **Regulatory Risk**

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

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

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

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

The industrial customer deliveries deferral account records the extent to which margin recovery from actual deliveries to Alcan and BC Hydro varies from forecast margin recovery used for rate making purposes based on forecast deliveries.

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

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

## **Liquidity, Cash Flow, and Capital Availability Risks**

The Company's credit facilities include a \$25 million operating line, two risk management facilities secured with \$20 million debentures issued by the Company and a \$35 million committed 5-year term revolving debt facility. In order to ensure that the operating line is utilized for its intended working capital purposes, the Company

covenants to reduce its borrowings under the line to zero for a 30 day consecutive period each fiscal year. In addition, the credit facilities are subject to financial covenants that may act to restrict the amounts that can be borrowed under the operating line and the 5-year term revolving debt facility.

The Company's operating line and risk management facilities are subject to renewal after 18 months with the operating line and one risk management facility maturing on May 28, 2012 and the other risk management facility maturing on July 21, 2012.

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

### **Facility and Insurance Risk**

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

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

### **Environmental and Safety Risks**

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

The number of existing and proposed greenhouse gas ("GHG") legislation, cap and trade programs and emissions regulations in North America and the world is expanding rapidly. In Canada, the federal government has delayed its implementation of a proposed national GHG cap-and-trade system until 2012 in order to harmonize with U.S. plans. As a partner in the Western Climate Initiative ("WCI"), B.C. has enacted legislation and developed regulations aligned with the principles agreed to by the WCI partners. B.C. has implemented reporting regulations that harmonize with the WCI draft requirements and support the planned for cap-and-trade program. The Mandatory Reporting of Greenhouse

Gas Emissions Regulation requires facilities and/or entities with emissions in most source categories to submit data on greenhouse gas emissions to the Minister of Environment, which will provide a foundation for the development and implementation of a cap and trade system and other climate policies to reduce greenhouse gases. Under the proposed regulation, facilities emitting more than 10,000 tonnes CO<sub>2</sub> equivalents per year will be required to report their annual GHG emissions beginning with the 2010 calendar year, with the first report due April 1, 2011.

Based on the applicable emissions thresholds set out in the draft federal and existing provincial regulations, the Company expects its compliance obligations to be small. However, as the federal regulations remain in development, it is not possible at this time to assess the full extent of their impact on the Company. In addition, the effects of climate change on the Company's service territories over the long term may manifest themselves in changes to customers' consumption patterns, as well as to changes in the level and nature of geotechnical and hydrological threats to the Company's pipeline systems. The Company recognizes the entire spectrum of influences that climate change may exert on its operations and continues to monitor, and influence as appropriate, related policies, regulations and developments.

### **Acquisition and Integration Strategies**

As part of its business strategy, the Company may pursue strategic acquisitions. There can be no assurance that the Company will find additional attractive acquisition candidates or succeed at effectively maintaining the integration of any businesses acquired in the future.

Acquisitions involve a number of risks, including: (a) the possibility that the Company, as a successor owner, may be legally and financially responsible for liabilities of prior owners; (b) the possibility that the Company may pay more than the acquired company or assets are worth; (c) the possibility of incurring additional expenses associated with completing an acquisition and amortizing any acquired intangible assets; (d) the difficulty of integrating the operations and personnel of an acquired business; (e) the challenge of implementing standard controls, procedures and policies throughout an acquired business; (f) the inability to integrate, train, retain and motivate key personnel of an acquired business; and (g) the potential disruption of the Company's ongoing business and the distraction of management from its day-to-day operations. These risks and difficulties, if they materialize, could disrupt the Company's ongoing business, distract management, result in the loss of key personnel, increase expenses and otherwise have an adverse effect on the Company's business, results of operations and financial performance.

In addition, as the Company seeks to grow and diversify its operations, the risk profile of its business may change. There may be greater economic exposure and more "at risk" capital with the expansion of the Company's business activities. While the Company will pursue growth initiatives by incurring risk that is felt to be justified by expected returns and managed effectively, there can be no assurances that such risks can be avoided.

## **Renewable Energy Business Risks**

The revenue earned by McNair Creek is proportional to the amount of electrical energy generated from the facility. The electricity generation is directly related to the levels of precipitation in the catchment area of McNair Creek which can vary from year to year. This facility is also subject to risks related to premature wear or failure, defects in design, material or workmanship and longer than anticipated down times for maintenance and repair. These risks are partially mitigated by the proven nature of the technology employed, and the regular maintenance and the design of the facility.

All of the electricity generated by the McNair Creek facility is sold to BC Hydro under a long-term energy purchase agreement. This energy purchase agreement will expire in 2024 and there can be no assurance that the Company will be able renegotiate or enter into another energy purchase agreement on terms that are commercially reasonable.

## **Derivatives Risk**

The Company uses derivative and other financial instruments in connection with the management of gas supply prices and interest rates. Forward, future, swap, fixed price and option contracts are used to manage the impact of market fluctuations on assets, liabilities or other contractual commitments. The Company could, however, incur financial losses in the future as a result of market or price volatility. Furthermore, because the valuation of these financial instruments can involve estimates, changes in the assumptions underlying these estimates can occur, changing the Company's valuation and potentially resulting in financial losses. This risk could affect the Company's liquidity, and regulatory approval would be required for the recovery of related costs through future rate adjustments.

## **Employee Future Benefits Plan Risk**

The Company has a defined benefit pension plan for the majority of its employees and retirees. Contributions to the plan are established by actuarial valuations prepared every three years and filed with the appropriate regulatory authorities. The most recently filed valuation was prepared as at December 31, 2009. The Company's actuaries were engaged to prepare this valuation. Should investment returns be less than the actuarial assumption or declining discount rates drive up the solvency liabilities in future valuations, this may lead to increased pension costs in future years. The next valuation is required to be prepared as at December 31, 2012 and will determine the contributions required from 2013 onwards.

## **Human Resources Risks**

Most of the employees of the Company are members of a union. Labour disruptions associated with the collective bargaining process could impact the Company's ongoing operations. In addition, the Company is dependent on maintaining its ability to attract and retain employees with the requisite skill and capabilities to operate in the complex and competitive energy industry.

## **First Nations Matters**

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

## **Share Price Volatility**

A number of factors could influence the volatility in the trading of the Common Shares, including changes in the economy or in the financial markets, and in particular the current global financial issues, industry-related developments, the impact of changes in the Company's operations and regulatory decisions affecting the Company, including decisions relating to return on equity and deemed equity. In addition, variations in earnings estimates by securities analysts and the market prices of the securities of companies in the same industry as the Company may also lead to fluctuations in the trading price of the Common Shares.

## **Transition to International Financial Reporting Standards**

As previously discussed under "Changes in Accounting Policies – Future Accounting Pronouncements", the Company makes use of specific policies under Canadian GAAP to account for its rate-regulated activities. This includes the use of regulatory assets and regulatory liabilities which allow the economic impact of rate-regulated activities to be recognized in the financial statements in a manner consistent with the timing by which amounts are reflected in customer rates.

Effective January 1, 2012, the Company is required to report under IFRS, including the presentation of IFRS-compliant comparative figures for fiscal 2011. Under existing IFRS guidance and practice, the Company's current accounting policies for rate-regulated activities are not allowed. Financial results under IFRS will be prepared without the use of regulatory deferral accounts and this may result in increased volatility in the Company's reported financial results.

The Company will develop and present a communications strategy to its shareholders and other stakeholders explaining the impacts of IFRS adoption and the rate-setting process on its financial results and financial position.