Western Plains Petroleum Ltd.

MANAGEMENT'S DISCUSSION & ANALYSIS
Three months ended March 31, 2012

OVERVIEW OF THE COMPANY

Western Plains Petroleum Ltd. (the "Company" or "Western Plains" or "WPP") is a **heavy oil producer based in Lloydminster, Alberta.** The Company was incorporated under the Business Corporations Act (Alberta) on November 19, 2004 and has traded on the TSX Venture Exchange ("TSXV") since August 2006. Following various name changes and trading symbols the Company began trading under the symbol "WPP" on the TSXV in 2009.

The Company focuses on the following strategies:

1. **production of conventional heavy oil,** building on the core competency of its people; and
2. acquisitions, exploration and development in the Lloydminster area (Lloydminster is a border city 250 km east of Edmonton, Alberta and 275 km west of Saskatoon, Saskatchewan).

The Company announced in February 2012 that the Board of Directors had appointed a special committee of independent Board members with a mandate to undertake a process to evaluate the various strategic alternatives available to Western Plains with the goal of maximizing shareholder value. These alternatives may include, but are not limited to, the spinout of certain properties of Western Plains or other business combinations. In April 2012 the Company announced it had engaged an exclusive financial advisor and agent to assist in identifying and evaluating possible liquidity events. No decision on any particular alternative has been reached at this time.

GENERAL

This management's discussion and analysis ("MD&A") of Western Plains for the three months ended March 31, 2012 contains financial highlights but does not contain the complete financial statements of the Company. It should be read in conjunction with the Company's unaudited interim financial statements for the three months ended March 31, 2012 and the audited annual financial statements for the year ended December 31, 2011. Additional information is available on SEDAR at www.sedar.com. The financial information presented herein has been prepared on the basis of International Financial Reporting Standards ("IFRS"). All references to dollar amounts are in Canadian dollars.

This MD&A includes events up to May 29, 2012.

NON-IFRS MEASURES

The Company's management uses and reports certain measures not prescribed by International Financial Reporting Standards (referred to as "non-IFRS measures") in the evaluation of operating and financial performance. Operating netback, which is calculated as average unit sales prices less unit royalties and operating expenses, and corporate netback, which further deducts unit administrative and interest expense, represent net cash margin calculations for every barrel of oil equivalent sold. Net debt, which is current assets less current and other financial liabilities, is used to assess efficiency and financial strength. Operating netback, corporate netback and net debt do not have any standardized meanings prescribed by International Financial Reporting Standards ("IFRS") and therefore may not be comparable with the calculation of a similar measure for other companies. The Company uses these terms as an indicator of financial performance because such terms are often utilized by investors to evaluate junior producers in the oil and natural gas sector.

HIGHLIGHTS

The Company has developed a concentrated asset base in close proximity to its operational and corporate offices in Lloydminster, Alberta. Key properties are Maidstone, Saskatchewan, Landrose, Saskatchewan and Lloydminster, Alberta.

2012 Acquisitions and Dispositions

The Company has no acquisitions in 2012. In May 2012 the Company entered into an agreement to sell an undeveloped oil property to a related party for $280,000. The proceeds from this sale are to be applied to the working capital deficiency to meet the covenant in the loan agreement with the bank.

2011 Acquisitions and Dispositions

In March 2011, the Company acquired, from an arm's length party, a 100% working interest and operatorship in oil and natural gas assets located near Maidstone, Saskatchewan. The purchase price was $754,000, subject to normal industry adjustments to the effective date of December 1, 2010. Consideration consisted of cash, assumption of certain trade payables of the vendor and the assumption of the related decommissioning obligations. Effective December 31, 2011, a 36% working interest in this property was sold for cash proceeds of $450,000. Western Plains continues as the operator of the property.

In February 2011 Western Plains entered into an arms-length farm out agreement for two LSDs on 2 different sections in the Standard Hill and Buzzard areas of Saskatchewan for $40,000. The Company drilled a 100% WI well at Standard Hill in 2011 and is currently in discussions with the farmor regarding the Buzzard commitment.

In November 2011, a related party and the joint interest partner on one well drilled in 2011 in the Edam, Saskatchewan area, purchased the Company's 50% working interest for $400,000, the proceeds of which were used to reduce debt.

Production and Revenue

Revenue for the first quarter of 2012 was $794,119 compared to $647,728 for first quarter of 2011 with the increase driven primarily by higher prices for heavy oil. Sales volumes of heavy oil in 2011 averaged 151 bbls per day compared to 128 bbls per day for Q1 2012. Q4 11 averaged 178 bbls per day with revenues of $1,195,894. The decline in volume from Q4 11 to Q1 12 was a result of wells off production awaiting repairs or a workover. A significant portion of the capital expenditures in Q1 2012 of $533,898 related to workovers and replacement equipment, necessary to restore production. March 2012 production was approximately 150 bbls per day.

One (0.5 net) well was drilled in March 2012 and was placed on production late that month. This well averaged 122 (61 net) bbls per day in the month of April 2012.

The 2011 average realized price per bbl. for Western Plains' heavy oil was $65.70 compared to $68.89 for Q1 2012. An increase in the heavy oil differential in March 2012 reduced the

Company's average realized price to approximately $60.00 per bbl., adversely impacting revenues for that month, notwithstanding the increased production.

OUTLOOK

The Company announced in February 2012 that the Board of Directors had appointed a special committee of independent Board members with a mandate to undertake a process to evaluate the various strategic alternatives available to Western Plains with the goal of maximizing shareholder value. These alternatives may include, but are not limited to, the spinout of certain properties of Western Plains or other business combinations. In April 2012, the Company announced it had engaged an exclusive financial advisor and agent to assist in identifying and evaluating possible liquidity events. No decision on any particular alternative has been reached at this time.

Western Plains has identified other potential drilling locations for 2012 and beyond in its core areas of operations. Capital costs are budgeted to be approximately $425,000 gross for each well, including drilling, completion and equipping.

The wells reactivated in Q1 2012 together with the one (0.5 net) newly drilled and completed well in late March 2012 increased average production in April to approximately190 bbls per day. The price differential between light oil and heavy oil has narrowed in Q2 2012 which is expected to result in higher revenues in Q2 2012.

LIQUIDITY AND CAPITAL RESOURCES

Western Plains' primary sources of liquidity to meet operating expenses and fund its development capital program are derived from the Company's internal funds flow from operations and its revolving operating bank credit facility. Western Plains utilizes this facility to fund daily operating activities and acquisitions as needed.

At March 31, 2012, the Company's credit facility agreement with a Canadian chartered bank consisted of two facilities:

- a revolving operating facility limit of $2,200,000 (increased from $1,000,000 at December 31, 2011) with interest at bank prime plus 1.5%, and
- a development facility limit of $300,000 with interest at bank prime plus 2.0%.

The Company drew on the revolving operating facility intermittently throughout 2011 with a draw at March 31, 2012 of $1,375,000.

At March 31, 2012 the Company was in breach of the working capital covenant prescribed in the loan agreement with the bank by approximately $200,000. The working capital deficiency was a result of the following:

- reactivation costs (both capital and operating expenditures) incurred in Q1 2012 to restore production on down wells;
- capital costs related to drilling, completing and equipping a new well in the second half of March 2012;

- lower production levels in January and February due to the down wells;
- an unfavorable heavy oil price differential in March 2012 resulting in a realized price of \$59.56 compared to \$93.60 for January 2012 and \$81.91 for February 2012.

The working capital covenant requires that Western Plains maintain a working capital ratio of 1:1. The actual working capital ratio was 0.91:1. The Company expects to resolve the working capital deficiency by selling a non-producing property in May 2012 for \$280,000 and has implemented a freeze on further capital spending. The higher production in the months subsequent to the period end (e.g. average production of approximately190 bbls per day in April 2012) is expected to provide sufficient cash inflow to meet obligations as they become due.

The Company has not yet received a response from the bank regarding the Company's request that the bank waive the breach in light of the remedial actions taken subsequent to the period end.

The Company's bank indebtedness does not have a specific maturity date as it is a demand facility. This means that the lender has the ability to demand repayment of all outstanding indebtedness or a portion thereof at any time. If that were to occur the Company would be required to source alternate credit facilities or sell assets to repay the indebtedness. The Company reduces this risk by maintaining a minimal balance on the facility. On an ongoing basis the Company manages its capital expenditures to ensure that cash flow and or access to credit facilities is available to fund these capital expenditures. The Company has the flexibility to adjust capital expenditures and manage its payments to trade creditors based on cash flow to manage debt levels.

As at March 31, 2012 and December 31, 2011, the Company had 55,101,153 common shares outstanding. In addition the Company had 4,860,000 stock options outstanding (4,960,000 at December 31, 2011) under its stock option plan. The stock options have exercise prices ranging from \$0.11 to \$0.21 per share with a weighted average exercise price of \$0.15 per share. An additional 200,000 stock options were issued in May 2012.

FINANCIAL AND OPERATING SUMMARIES
TABLE A - OPERATIONS BY QUARTER

All production is conventional heavy oil	IFRS	IFRS	IFRS	IFRS	IFRS	IFRS	IFRS	IFRS
$000's except for Production and per share	**Q1 2012**	**Q4 2011**	**Q3 2011**	**Q2 2011**	**Q1 2011**	**Q4 2010**	**Q3 2010**	**Q2 2010**
Sales volume - total barrels	11,527	16,363	16,953	10,959	11,003	12,446	3,410	4,498
Sales volume - bbls/ day	**128**	**178**	**184**	**120**	**122**	**135**	**37**	**49**
Heavy oil revenue	794	1,196	1,001	787	648	756	222	262
Royalties	(156)	(263)	(178)	(148)	(106)	(146)	(31)	(30)
Production & transportation	(422)	(554)	(300)	(441)	(285)	(296)	(104)	(149)
Operating net back	216	379	523	198	257	314	87	83
General, administrative & transaction	(135)	(232)	(280)	(137)	(156)	(219)	(242)	(208)
Bank interest & loan fees	(9)	(3)	(10)	-	(3)	-	-	-
Corporate net back (loss)	134	144	233	61	98	95	(155)	(125)
Depletion, depreciation & accretion	(168)	(242)	(266)	(197)	(158)	(181)	(63)	(72)
Other non-cash income (expenses)	-	(59)	381	(67)	61	(265)	(38)	(144)
Income (loss) for the quarter	**(96)**	**(157)**	**348**	**(203)**	**1**	**(351)**	**(256)**	**(341)**
Basic and diluted income (loss) per share	**(.00)**	**(.00)**	**.01**	**.00**	**.00**	**(.01)**	**(0.01)**	**(0.01)**
Royalties as % of petroleum revenue	**20**	**22**	**18**	**19**	**16**	**19**	**14**	**11**
Per bbl. analysis	**Per bbl.**	**Per bbl.**	**Per bbl.**	**Per bbl.**	**Per bbl.**	**Per bbl.**	**Per bbl.**	**Per bbl.**
Heavy oil revenue	68.89	73.09	59.05	71.79	58.89	60.73	65.20	58.31
Royalties	(13.54)	(16.07)	(10.50)	(13.47)	(9.63)	(11.76)	(9.07)	(6.57)
Production and transportation	(36.65)	(33.86)	(17.70)	(40.27)	(25.90)	(23.86)	(30.39)	(33.17)
Operating net back	**18.70**	**23.16**	**30.85**	**18.05**	**23.36**	**25.11**	**25.74**	**18.57**
General, administrative & transaction	(11.68)	(14.18)	(16.52)	(12.47)	(14.18)	(17.62)	(70.98)	(46.46)
Bank interest and loan fees	(0.77)	(0.18)	(0.61)	-	(0.27)	-	-	-
Corporate netback (loss)	6.26	8.80	13.72	5.58	8.91	7.49	(45.24)	(27.79)
Depletion, depreciation & accretion per bbl.	(14.56)	(14.79)	(15.69)	(17.98)	(13.63)	(14.54)	(18.48)	(16.01)
WPP revenue per bbl.	**68.89**	**73.09**	**59.05**	**71.79**	**58.89**	**60.73**	**65.20**	**58.31**
Benchmark prices								
Edmonton light 40 API	92.81	97.87	92.27	102.63	88.51	80.71	76.02	75.46
Hardisty heavy 12 API	72.35	77.83	61.98	73.21	62.36	62.30	60.57	59.67
Heavy oil differential	20.46	20.04	30.29	29.42	26.15	18.41	15.45	15.79

FINANCIAL AND OPERATING SUMMARIES
TABLE B – BALANCE SHEET

$000's	**Q4 2011**	**Q4 2011**	**Q3 2011**	**Q2 2011**	**Q1 2011**	**Q4 2010**	**Q3 2010**	**Q2 2010**
Net cash (debt)	(2,409)	(1,947)	(1,844)	(1,748)	(593)	204	(141)	(395)
Total assets	9,766	9,534	9,691	8,814	7,504	7,305	5,020	4,439
Total liabilities	4,929	4,602	4,675	4,145	2,632	2,436	1,742	1,443
Shareholders' equity	4,837	4,932	5,016	4,669	4,872	4,869	3,278	2,996
SHARES 000's								
Basic outstanding	55,101	55,101	55,101	55,101	55,101	55,101	45,732	42,137
Weighted average	55,101	55,101	55,101	55,101	55,101	49,115	43,544	33,456

Development and Acquisition Activity

The following property transactions and development activities (all heavy oil properties near Lloydminster, Alberta) affected average production levels and explain most of the quarter over quarter production and revenue variances for the operating periods shown in the "Financial and Operating Summaries" in Table A:

- Q2 2010 – acquired 100% working interest and operatorship in the Landrose, Saskatchewan property, with common shares as consideration.
- Q3 2010 – disposed of 50% working interest in all producing and non-producing properties while retaining operatorship of all the oil and natural gas assets.
- Q3 2010 – acquired a 33 1/3% working interest and operatorship of the Blackfoot, Alberta oil and gas assets.
- Q3 2010 – completed and placed on production 2 (0.67 net) wells (drilled and cased but not previously completed) on the acquired property.
- Q3 2010 – drilled one well (0.25 net after payout in April 2011) at Landrose, Saskatchewan.
- Q4 2010 – drilled and placed on production 5 (2.5 net) wells at Landrose, Saskatchewan.
- Q4 2010 – completed and placed on production 2 (.67 net) additional wells (drilled and cased but not previously completed) on the property acquired in Q3 2010.
- Q1 2011 – entered into a farm-out agreement to acquire two LSDs on two different sections of land in the Standard Hill and Buzzard areas of Saskatchewan.
- Q1 2011 – drilled 1 successful oil well (0.33 net) on the Blackfoot, Alberta heavy oil property.
- Q1 2011 – acquired additional oil and natural gas assets at Maidstone, Saskatchewan.
- Q2 11 – reactivated 5 (5 net) wells on the acquired Maidstone property.
- Q2 11 – drilled 4 (2.67 net) successful oil wells.
- Q3 11 – drilled 2 (1.0 net) successful oil wells.
- Q4 11 – disposed of a 36% working interest (cash proceeds of $450,000) of the oil and natural gas assets at Maidstone, Saskatchewan which were acquired in Q1 11.
- Q4 11 – drilled 1 (0.15 net before payout and 0.35 after payout) successful oil well. There was no cash cost to Western Plains as it contributed equipment from a shut in well to equip this new well.
- Q1 12 – drilled 1 (0.5 net) successful oil well at Landrose, Saskatchewan with very promising initial flush production.
- Q2 12 – entered into an agreement to sell an undeveloped oil property for $280,000.

OPERATING RESULTS

Production volumes and revenues (refer to Table A)
The Company's average production for Q1 2012 was 128 bbls per day of heavy oil which was comparable to the 122 bbls per day for Q1 2011. However Q4 2011 averaged 178 bbls. The decline in volume in Q1 2012 from Q4 2011 was a result of wells off production awaiting repairs or workovers. The down wells were repaired or subject to a workover and a new well was drilled, completed and commenced production in late March 2012, resulting in production for that month of approximately 150 bbls per day. April production was approximately 190 bbls per day, benefiting from the new well producing the entire month. The 4 (2.67 net) wells drilled in Q2 11 commenced production after Q2 2011 as well as 1 (0.5 net) well drilled in Q3 2011. This accounts for the increase in Q3 and Q4 of 2011 compared to Q1 and Q2 of 2011.

Oil Pricing

All of Western Plains' crude oil consists of heavy oil produced in Saskatchewan and Alberta that is marketed based on refiners' posted prices for heavy oil, adjusted for the quality (primarily density) of the crude oil on a well by well basis. The majority of Western Plains' heavy oil ranges in density from approximately 13.6° API to 15.9° API. The refiners' posted prices are influenced by the US$ WTI reference price, transportation costs, US$/C$ exchange rates and the supply/demand situation of particular crude oil quality streams during the year.

The price differential between light oil and heavy averaged $20.43 in Q1 2012 compared to $26.15 for Q1 2011. The differential was $25.31 in March 2012, 20% higher than the Q1 12 average of $20.43. This adversely affected the Company's revenue for this month which was the highest production volume of the three months in the quarter.

Royalties (refer to Table A)

The Company incurs a mix of crown, freehold and overriding royalties. The volumes and mix of oil wells producing in a quarter impact the overall average royalty burden. Q1 12 overall royalty burden averaged 20% compared to 16% for Q1 11. Q2 11 includes the higher production volumes from the recently drilled wells. The higher production volumes and strong oil prices triggers a higher royalty burden under the crown regimes. This accounts for the increase from the 2010 overall royalty burden of 17% compared to the 2011 overall royalty burden of 19% and the 2012 royalty burden of 20%.

Production and transportation costs (refer to Table A)

As explained elsewhere the Company experienced a number of down wells early in Q1 2012 which required workovers, replacement equipment and repairs. The repair costs increased production costs leading to the average of $39.97 for the quarter. Higher propane and other winter operating costs also contributed to this higher average.

Production and transportation costs in 2011 averaged $28.56 per bbl. compared to $28.11 per bbl. for 2010. The wet spring and summer in 2011 contributed to higher operating costs. Winter operating costs are higher than other seasons as certain costs (e.g. snowplowing) are incurred only in cold weather. Heavy oil production costs tend to be higher than light oil production costs.

WPP transportation costs are low and comprise only the trucking of clean oil short distances to the sales terminal.

Some quarters include abandonment or workover costs for certain wells and those costs contribute to higher per bbl. operating costs in those quarters. The Maidstone oil and gas assets acquired in 2011 required significant reactivation costs as well as repairs and other costs giving rise to significant production costs in 2011. The property should benefit from this investment with more consistent production in 2012. A 36% working interest of this property was sold effective December 31, 2011, for cash proceeds of $450,000.

General and administrative, including transaction costs (G&A) (refer to Table A)

The Q1 12 average G&A costs of $11.68 per bbl. is consistent with prior periods. As production increases as a result of development work and further acquisitions, G&A costs per bbl. decline as these costs tend to be fixed. G&A expenses for 2011 averaged $14.60 per bbl., down considerably from the 2010 annual average of $29.16 per bbl.

The higher level of capital and operating activity in 2011 explains the increase in G&A costs from $770,926 in 2010 to $806,733 in 2011.

The Company contracts all G&A services and has no employees. This includes the President and CEO position for which consulting fees are paid to a company with an officer and director in common with Western Plains.

Bank interest and loan fees (refer to Table A)

The Company drew on its bank credit facilities for the first time in Q1 2011 giving rise to bank interest and loan fees for the first time in that quarter. Accretion on the decommissioning provisions is a component of finance expense on the statement of operations in the financial statements but is shown as other non-cash expense in the analysis in Table A.

Depletion, depreciation & accretion (refer to Table A)

Depletion expense is a function of volume produced as it is computed on a “units of production” basis using proved plus probable reserves as the depletion base. The significant increase in the expense in Q3 and Q4 2011 relates to the higher volume of production. Similarly depletion expense increased in Q4 2010 due to the production increase. Capital expenditures were significant in Q2 and Q3 2011. These capital expenditures added to the costs subject to depletion and contribute to the higher costs of depletion per bbl. in 2011 of $15.30 per bbl. compared to $10.66 per bbl. in 2010. Q1 2012 depletion, depreciation and accretion per bbl. in Q1 2012 of $14.56 was consistent with the 2011 average of $15.30 per bbl.

INCOME TAX

The Company had the following tax pools:

Nature of tax pool	Deduction %	December 31, 2011 $000's
Canadian oil and gas property expense (COGPE)	10	2,320
Canadian development expense (CDE)	30	643
Canadian exploration expense (CEE)	100	660
Foreign exploration & development expense	10	425
Undepreciated capital cost (UCC)	25	1,462
Share issue costs	20	67
Non capital loss carry forward	100	1,406

The non-capital loss carry forward expires in 2025 to 2031.

The recovery of income taxes in 2011 relates to the renouncement of certain tax expenditures to flow through share investors. The Company has not recorded any future tax asset or liability, nor has it recorded any tax recovery related to its operating losses in, due to the uncertainty of the Company's ability to fully utilize the available income tax pools against its future income.

The Company is eligible to substitute up to $1 million development expenditures for exploration expenditures because its taxable capital is under the limit of $15 million as prescribed in the Income Tax Act (Canada).

CRITICAL ACCOUNTING ESTIMATES

Management is often required to make judgments, assumptions and estimates in the application of generally accepted accounting principles that may have a significant impact on the financial results of the Company. The Company's significant accounting policies are described in notes in the audited financial statements at December 31, 2011 and are discussed in the MD&A for December 31, 2011. Additional information is available on SEDAR at www.sedar.com

NEW ACCOUNTING STANDARDS

The impact of new accounting standards are described in notes to the audited financial statements at December 31, 2011 and are discussed in the MD&A for December 31, 2011. Additional information is available on SEDAR at www.sedar.

OFF BALANCE SHEET ARRANGEMENTS

The Company has not engaged in any off-balance sheet arrangements such as obligations under guarantee contracts, a retained or contingent interest in assets transferred to an unconsolidated entity, any obligation under derivative instruments (except as disclosed) or any obligation under a material variable interest in an unconsolidated entity that provides financing, liquidity, market risk or credit risk support to the Company or engages in leasing or hedging services with the Company.

INDUSTRY CONDITIONS AND RISKS

The business of exploration, development and acquisition of oil and gas reserves involves a number of business risks inherent in the oil and gas industry which may impact The Company's results and several of which are beyond control of the Company. These business risks are operational, financial or regulatory in nature. These risks and the Company's approach to managing these issues are the same as disclosed in the Management's Discussion and Analysis for the year ended December 31, 2011.

RELATED PARTY TRANSACTIONS

The financial statements of Company include balances and transactions with directors and officers of the Company, or with companies related to directors or officers of the Company. These related party transactions, all of which were in the normal course of operations and have been valued at the exchange amount that is the amount of consideration established and agreed to by the related parties, are summarized as follows:

- Legal services were provided by a law firm in which Leigh Stewart, Corporate Secretary and Director of Western Plains is an employee at a cost of approximately $39,000 in Q1 2012.

- Various transactions occurred with corporations in which David Forrest, President, CEO and Director of the Company, is an officer and a director:
    - Approximately $248,000 was incurred for various oil field services in Q1 2012, primarily related to contacting a service rig to perform work on Western Plain's wells;
    - $14,580 is paid per month as fees throughout 2011 and 2012 for the services of Mr. Forrest as President and CEO of the Company; and

- Certain oil and natural gas properties are held as joint arrangements (working interest partner) with an entity with which David Forrest, Steven Glover, Vice President and Chief Financial Officer and Stephen Johnston, Director are or were involved in management roles:
    - Two (1.0 net) wells were drilled in 2011 as 50/50 partners pursuant to farm in agreements;
    - Non-producing property is to be sold to the partner subsequent to the period end for $280,000, pursuant to a purchase and sale agreement entered into in May 2012.
    - The Company sold its 50% working interest in one of these wells to this related party in November 2011 for cash proceeds of $400,000; and
    - Normal joint interest partner transactions were conducted throughout the year in accordance with normal industry practices in relation to the jointly owned heavy oil property.

Forward-Looking Statements

The matters discussed in this MD&A include certain forward-looking statements. Forward-looking statements include, without limitation, any statement that may predict, forecast, indicate or imply future results, performance or achievements. Forward-looking statements may be identified, without limitation, by the use of such words as "anticipates", "estimates", "expects", "intends", "plans", "predicts", "projects", "believes", or words or phrases of similar meaning. In addition, any statement that may be made concerning future performance, strategies or prospects and possible future corporate action, is also a forward-looking statement. Forward-looking statements are based on current expectations and projections about future general economic, political and relevant market factors, such as interest rates, foreign exchange rates, equity and capital markets, and the general business environment, in each case assuming no changes to applicable tax or other laws or government regulation. Expectations and projections about future events are inherently subject to, among other things, risks and uncertainties, some of which may be unforeseeable. Accordingly, assumptions concerning future economic and other factors may prove to be incorrect at a future date. Forward-looking statements are not guarantees of future performance, and actual events could differ materially from those expressed or implied in any forward-looking statements made by the Company. Any number of important factors could contribute to these digressions, including, but not limited to, general economic, political and market factors in North America and internationally, interest and foreign exchange rates, global equity and capital markets, business competition, technological change, changes in government relations, unexpected judicial or regulatory proceedings and catastrophic events. We stress that the above mentioned list of important factors is not exhaustive. We encourage you to consider these and other factors carefully before making any investment decisions and we urge you to avoid placing undue reliance on forward-looking statements. The Company disclaims any intention or obligation to update or revise these forward-looking statements as a result of new information, future events or otherwise, except as required under applicable securities laws.

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