Western Plains Petroleum Ltd.

MANAGEMENT'S DISCUSSION & ANALYSIS
Three and Nine Month Periods ended September 30, 2010 and 2009

OVERVIEW OF THE CORPORATION

Western Plains Petroleum Ltd. (the "Corporation" or "Western Plains" or "WPP") is a heavy oil producer based in Lloydminster, Alberta. The Corporation 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 names changes and trading symbols the Corporation began trading under the symbol "WPP" on the TSXV on August 25, 2009.

The Corporation focuses on the following strategies:

1. production of conventional heavy oil, building on the core competency of its people;
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); and
3. careful control of development and production costs.

At the end of Q1 09, Western Plains carried net debt of $2.6 million which represented a debt to annualized cash flow of 5:1. While production at that time was in excess of 200 bbls per day, the debt situation was unacceptable. As a result, management initiated a series of transactions over the last 18 months to eliminate the bank debt and free up capital for more profitable and sustainable opportunities. To achieve this objective, assets were sold and other properties were acquired with development potential to replace the lost production. Currently WPP is producing approximately 225 bbls per day and has no debt. As our production profile continues to increase, we anticipate higher netbacks per bbl as costs per bbl for general and administrative (G&A) and production will decrease.

GENERAL

This management discussion and analysis ("MD&A") of Western Plains for the three and nine months ended September 30, 2010 contains financial highlights but does not contain the complete financial statements of the Corporation. It should be read in conjunction with the Corporation's audited financial statements for the year ended December 31, 2009 and unaudited financial statements for the three and nine months ended September 30, 2010. Additional information is available on SEDAR at www.sedar.com. The financial information presented herein has been prepared on the basis of Canadian generally accepted accounting principles ("GAAP"). All references to dollar amounts are in Canadian dollars.

This MD&A includes events up to November 22, 2010.

NON-GAAP MEASURES

The Corporation's management uses and reports certain measures not prescribed by generally accepted accounting principles (referred to as "non-GAAP 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 GAAP and therefore may not be comparable with the calculation of a similar measure for other companies. The Corporation 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 OF 2010

As described in the above “Overview of the Corporation” Western Plains executed an 18 month strategy to eliminate its $2.6 million debt, outstanding at the end of Q1 09. Assets were sold to pay down the debt but replaced with other properties financed without debt. Development activity on the new properties restored the Corporation to the Q1 09 production levels of 225 bbls per day. The 2010 transactions and the strengthening of management and governance, which were part of this longer term objective, are described below. These transactions provide a more diversified, high potential property base, strong management and governance team, and the capital resources to execute an aggressive development program to continue the strong production growth of the last few months.

June 2010 Acquisition

In June 2010, the Corporation closed the acquisition of 100% working interests in petroleum and natural gas rights located in the Lloydminster area of Saskatchewan, adding approximately $1.7 million to property, plant and equipment. Consideration consisted of 10,000,000 common shares and the assumption of the related asset retirement obligations.

In August 2010, Western Plains completed a divestment of 50% of all of its petroleum and natural gas assets, thereby reducing its interest in the Landrose asset from 100% to 50% (see “August 2010 Disposition and Acquisition” below).

August 2010 Disposition and Acquisition

On August 25, 2010 Western Plains closed the acquisition of a net 33 1/3% working interest in certain heavy oil assets located in the Lloydminster, Alberta area, comprised of 26 LSD’s (1,040 acres), including nine (9) shut-in (non-producing) heavy oil wells (previously producing) and five (5) standing cased wells (previously drilled but not completed). The acquisition added $1.7 million to property, plant and equipment. Consideration was a combination of cash, the issuance of common shares of the Corporation, the assumption of certain trade payables of the Vendor and the assumption of the related asset retirement obligations.

The Lloydminster assets were acquired in two-stages with the Corporation agreeing to acquire a 66 2/3% working interest (but only paying for a 33 1/3 % working interest), as it contemporaneously closed the sale of the other one third (33 1/3%) working interest to a third party purchaser, which paid the original vendor directly for such interest. As a result of this transaction, each of, Western Plains and the two other participating parties hold a 33 1/3% interest in these Lloydminster assets.

To fund the acquisition of these Lloydminster assets, on August 5, 2010, the Corporation divested a 50% undivided interest in all of its oil and gas assets located in the Lloydminster and Maidstone areas of Saskatchewan and in the Lloydminster area of Alberta, to the same third party purchaser. Property, plant and equipment was reduced by approximately $1,805,000 which was a combination of cash proceeds and the settlement of the related asset retirement obligation

These transactions significantly strengthened the balance sheet and positioned Western Plains for significant growth on a more diversified property base.

The Corporation has no bank debt and no bank debt was incurred in connection with any of the transactions.

Production and Revenue

Production, revenue and cash flow for this heavy oil producer increased rapidly subsequent to the period end. Current production is approximately 225 bbls per day. This is a significant increase over the average production for Q3 10 of 37 bbls per day, which compares to 50 bbls per day for Q3 09. The average production for the nine months ended September 30, 2010 was 51 bbls per day compared to 121 bbls per day for the nine months ended September 30, 2009. These declines are a result of property sales:

- August 2010 – sale of 50% working interest (WI) in the Maidstone and Lloydminster area properties amounting to approximately 25 bbls per day of heavy oil, and
- May 2009 – sale of 100% WI in the Golden Lake and Rush Lake areas of Saskatchewan amounting to approximately 180 bbls per day of heavy oil.

Nominally or non-producing heavy oil wells acquired in the Lloydminster area of Alberta in Q3 2009, were reactivated and account for most of the production in the nine months ended September 30, 2010.

Revenue in 2010 benefited from higher oil prices than 2009 as shown in the "Financial and Operating Summaries" on page 5. The Corporation averaged approximately $65.00 per bbl in Q3 10 which compares to just under $60.00 per bbl in Q3 09. A shutdown in the major pipeline to the United States in September 2010 resulted in a much lower price for that month which lowered the average for the quarter. For the nine months ended September 30, 2010, WPP averaged approximately $63.00 per bbl compared to approximately $44.00 for the nine months ended September 30, 2009. The latter is a result of the very low oil prices in the first half of 2009 and as reflected in the benchmark prices shown in "Financial and Operational Summaries" on Page 5.

Strengthening of Management and Governance

In October 2010, the Corporation announced that Steven Glover, FCA was appointed as Vice-President, Finance and Chief Financial Officer of the Corporation. Mr. Glover is a valuable addition to the management of the Corporation, adding considerable industry experience, including CFO roles with other listed entities.

In June 2010, the Corporation announced that William Koenig was appointed Director of the Corporation. Mr. Koenig brings many years of experience in corporate finance and governance, with a focus on the oil and natural gas industry.

OUTLOOK

Several drilling locations have been identified including on the Landrose property acquired in June 2010. The Corporation's land position continues to expand through acquisitions at Crown land sales and from other industry participants. The Corporation is able to finance growth from its strong working capital position, rapidly increasing cash flows, the well financed and motivated working interest partner, untapped $1.1 million credit facilities with a Canadian chartered bank, and additional equity raised subsequent to the period end (refer to "Liquidity and Capital Resources").

Western Plains, as operator, drilled three successful oil wells (1.25 net) in Q2 10 and Q3 10 on the Landrose, Saskatchewan (approximately 16 kilometres east of Lloydminster) property. These three wells are currently producing approximately 240 bbls per day (100 bbls per day net) of heavy oil from the McLaren formation. Drilling, completion and equipping costs for these three wells totalled approximately $1,200,000 ($400,000 net to Western Plains). This represents a cost of approximately $5,000 per flowing bbl.

Current production is approximately 225 bbls per day net to WPP. The Corporation expects to exit 2010 with net production of approximately 280 bbls per day, driven by continued development, including:

- Two (1 net) additional in-fill drilling locations in the Landrose, SK area.
- Continuous production from two recently completed wells (0.67 net) in the Lloydminster, AB area.

LIQUIDITY AND CAPITAL RESOURCES

The Corporation continues to strengthen its financial position with rapidly increasing production volumes, strong oil prices, control over costs and additional equity from time to time. In November 2010 private placements are in the midst of being marketed with an expected closing date before the end of the month:

- $0.18 per unit - Each unit consists of one common share and one-half of one common share warrant, with each whole warrant exercisable into one common share at an exercise price of $0.25 per share for a period of one year from the date of issuance.
- $0.22 "flow-through" common share – There is a requirement that eligible capital expenditures be incurred by December 31, 2011 under the look back rules of the Income Tax Act of Canada.

Subscriptions totaling over $1 million have been received to date.

As at September 30, 2010, the Corporation had a net working capital deficiency of less than $100,000 ($200,000 working capital deficiency at December 31, 2009). Subsequent cash flows from operations eliminated the working capital deficiency, as cash flows increased significantly with the increases in production.

In October 2010 the Corporation finalized a credit facility agreement with a Canadian chartered bank, consisting of a revolving operating facility of $800,000 with an interest rate of bank prime plus 1.5%, and a development facility of $300,000 with an interest rate of bank prime plus 2.0%. Neither facility has been drawn.

In the first nine months of 2010 Western Plains issued 2,144,167 common shares in two private placements (January 2010 - 1,877,500 common shares at $0.08 per share and August 2010 – 266,667 common shares at $0.15 per share), for gross proceeds of $190,200 and no finders' fees. In June and August 2010 13,328,363 common shares were issued to acquire oil and gas interests. As at September 30, 2010, the Corporation had 45,732,304 (30,259,774 at December 31, 2009) common shares outstanding, 3,352,941 warrants outstanding (exercise price of $0.15 and expire December 2010) and 2,452,000 stock options outstanding under its stock option plan.

The Corporation has a strong balance sheet with which to finance continued growth.

FINANCIAL AND OPERATING SUMMARIES

TABLE A - OPERATIONS BY QUARTER (Last 8 Quarters)

All production is conventional heavy oil

$000's except for Production and per share	**Q3 2010**	**Q2 2010**	**Q1 2010**	**Q4 2009**	**Q3 2009**	**Q2 2009**	**Q1 2009**	**Q4 2008**
Production - total barrels	3,410	4,498	6,091	6,294	4,624	7,824	20,529	20,107
Production - bbls/ day	**37**	**49**	**68**	**68**	**50**	**86**	**228**	**219**
Heavy oil revenue	222	262	394	389	277	411	770	859
Royalties	(31)	(30)	(73)	(49)	(50)	(94)	(172)	(196)
Production & transportation	(104)	(149)	(193)	(161)	(148)	(111)	(258)	(319)
Operating net back	87	83	128	179	79	206	340	344
General and administrative	(136)	(149)	(101)	(51)	(135)	(102)	(155)	(293)
Interest & financing	-	-	-	-	-	(58)	(54)	(52)
Corporate net back (loss)	(49)	(66)	27	128	(56)	46	131	(1)
Depletion & accretion	(59)	(145)	(112)	(116)	(111)	(101)	(701)	(671)
Other (expenses) revenue	-	(144)	-	-	85**	423*	-	(25)
Income (loss) for the period	**(108)**	**(355)**	**(85)**	**12**	**(82)**	**368**	**(570)**	**(697)**
Basic and diluted income (loss) per share	**(0.002)**	**(0.011)**	**(0.003)**	**0.000**	**(0.003)**	**0.017**	**(0.027)**	**(0.043)**
*gain on disposition of oil properties								
**gain on settlement of debt								
Royalties as % of petroleum revenue	**14**	**11**	**19**	**13**	**18**	**23**	**22**	**23**

Per bbl analysis	**Per bbl**	**Per bbl**	**Per bbl**	**Per bbl**	**Per bbl**	**Per bbl**	**Per bbl**	**Per bbl**
Heavy oil revenue	65.20	58.31	64.67	61.82	59.88	52.53	37.53	42.74
Royalties	(9.07)	(6.57)	(11.98)	(7.75)	(10.79)	(12.06)	(8.40)	(9.76)
Production and transportation	(30.39)	(33.17)	(31.75)	(25.53)	(32.02)	(14.17)	(12.56)	(15.85)
Operating net back	**25.74**	**18.57**	**20.94**	**28.54**	**17.07**	**26.30**	**16.57**	**17.13**
General and administrative	(39.99)	(33.21)	(16.59)	(8.11)	(29.31)	(13.10)	(7.55)	(14.59)
Interest and financing	-	-	-	-	-	(7.36)	(2.63)	(2.58)
Corporate netback (loss)	(14.25)	(14.64)	4.35	20.43	(12.24)	5.83	6.39	(0.04)
Depletion & accretion	(17.37)	(32.21)	(18.34)	(18.47)	(23.95)	(12.91)	(34.15)	(33.37)
Other (expenses) revenue	-	(32.06)	-	-	18.42	54.05	-	(1.23)
Income (loss) for the period	(31.62)	(78.92)	(13.99)	1.96	(17.77)	46.98	(27.76)	(34.64)
WPP revenue prices	**65.20**	**58.31**	**64.67**	**61.82**	**59.88**	**52.53**	**37.53**	**42.74**
Benchmark prices								
Edmonton light 40 API	76.02	75.46	80.31	76.75	71.70	66.19	50.15	63.94
Hardisty heavy 12 API	60.57	59.67	68.79	64.03	60.90	58.07	39.38	40.62
Heavy oil differential	15.45	15.79	11.52	12.72	10.80	8.12	10.77	23.32

Funds (invested in) recovered from petroleum properties	**263**	**(157)**	**(69)**	**(212)**	**(778)**	**2,703**	**(50)**	**(1,784)**

FINANCIAL AND OPERATING SUMMARIES
TABLE B -OPERATIONS FOR THE NINE MONTHS ENDED SEPTEMBER 30, 2010 AND 2009

All production is conventional heavy oil

$000's except for Production and per share	**9 months ended Sept 30, 2010**	**9 months ended Sept 30, 2009**
Production - total barrels	13,999	32,977
Production - bbls/ day	**51**	**121**
Heavy oil revenue	878	1,458
Royalties	(133)	(317)
Production & transportation	(446)	(517)
Operating net back	299	624
General and administrative	(387)	(412)
Interest & financing	-	(92)
Corporate net back (loss)	(88)	120
Depletion & accretion	(316)	(913)
Other (expenses) revenue	(144)	508*
Income (loss) for the period	**(548)**	**(285)**
Basic and diluted income (loss) per share	**(0.015)**	**(0.012)**
*gain on disposition of oil properties + gain on settlement of debt		
Royalties as % of petroleum revenue	**15**	**22**
Per bbl analysis	**Per bbl**	**Per bbl**
Heavy oil revenue	62.76	44.21
Royalties	(9.54)	(9.61)
Production and transportation	(31.68)	(15.68)
Operating net back	**21.54**	**18.92**
General and administrative	(27.63)	(12.49)
Interest and financing	-	(2.79)
Corporate netback (loss)	(6.09)	3.64
Depletion & accretion	(22.56)	(27.69)
Other (expenses) revenue	(10.30)	15.40
Income (loss) for the period	(38.59)	(8.65)

FINANCIAL AND OPERATING SUMMARIES
TABLE C – BALANCE SHEET

$000's	**Q3 2010**	**Q2 2010**	**Q1 2010**	**Q4 2009**	**Q3 2009**	**Q2 2009**	**Q1 2009**	**Q4 2008**
Net cash (debt)	(80)	(334)	(103)	(208)	(377)	174	(2,575)	(2,657)
Total assets	5,026	4,242	2,323	2,453	2,297	2,034	4,288	4,820
Total liabilities	1,473	1,120	483	674	783	637	3,258	3,220
Shareholders equity	3,553	3,122	1,840	1,779	1,514	1,397	1,030	1,600
SHARES 000's								
Basic outstanding	45,732	42,137	32,137	30,260	26,907	21,227	21,227	21,227
Weighted average	43,544	33,456	31,929	28,000	26,907	21,227	21,227	17,567

OPERATING RESULTS FOR 2010

Production volumes and revenues (refer to Financial and Operating Summaries on pages 5 & 6)

Q3 10 production was 37 bbls per day compared to Q3 09 production of 50 bbls per day. Production for the nine months ended September 30, 2010 was 51 bbls per day compared to production for the nine months ended September 30, 2009 of 121 bbls per day.

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 variances for the 8 quarters shown in the "Financial and Operating Summaries" on the prior two pages:

- Q2 2009 - disposed of all producing wells in the Golden Lake and Rush Lake areas of Saskatchewan reducing production by approximately 180 bbls per day.
- Q3 2009 – acquired six (6 net) non producing wells.
- Q4 2009 –activated and put on production non-producing wells acquired in prior quarter.
- Q2 2010 – acquired the Landrose, Saskatchewan property, with common shares as compensation
- Q2 2010 – consummated Joint Operating Agreement (JOA) naming WPP as field operator, for a property targeted for acquisition. All wells were shut in.
- Q2 2010 – reactivated several of the shut in wells under the JOA, and earned operating fees which have been recorded as a reduction of production expenses.
- Q2 2010 – performed successful workovers on two (2 net) wells which were shut in for two months prior to and during the workover process.
- Q3 2010 – disposed of 50% working interest in all producing and non producing properties.
- Q3 2010 – acquired a 33 1/3% working interest in the property for which Western Plains is field operator.
- Q3 2010 –completed and put on production 2 (0.67 net) of 5 wells (drilled and cased but not previously completed) on the acquired property.
- Q3 2010 –drilled one well (0.25 net) in the Landrose area with Western Plains as operator. A farm in partner paid 100% of the costs subject to a 10% convertible gross overriding royalty (GORR) of which 5% is payable to the Corporation until payout. At payout, expected by December 2010 , Western Plains will opt to take a 25% working interest in lieu of retaining the GORR.
- Q4 2010 – drilled and put on production 2 (1 net) wells in the Landrose area.
- Q4 2010 – completed and put on production 2 (.67) additional wells (drilled and cased but not previously completed) on the property acquired in August 2010.

This development program has increased production with current production of approximately 225 bbls per day net to Western Plains.

The Corporation will continue to increase production on this more diverse property base. The strong balance sheet, the unused credit facilities and the motivated and well financed partner will allow WPP to finance this continued production growth and the resulting increases in cash flow.

The realized average corporate prices per bbl for each of the quarters in the "Financial and Operating Summaries" are consistent with the Hardisty heavy oil benchmark also set out in Table A. The Corporation does incur a differential from the benchmark related to adjustments imposed by the purchaser. The average price realized in September 2010 was unfortunately just under $50.00 per bbl as the market was negatively affected by the shut down of a major pipeline into the US.

Royalties (refer to Financial and Operating Summaries on pages 5 & 6)

The "Financial and Operating Summaries" show royalty expense as a per cent of oil sales to be generally consistent over the eight quarters.

The production decline and lower prices in Q3 10 and Q2 10 compared to Q1 10 reduced the overall royalty burden under the declining scale method of determining Alberta crown royalties. A royalty refund was received and recorded in Q2 10. This explains the shift of royalty expense as a % of revenue of 11% in Q2 10 compared to 14% in Q3 10 and 19% in Q1 10. The decline since Q2 09 relates to the sale of most of the Saskatchewan properties in May 2009. The Saskatchewan wells incurred a higher royalty burden than the Alberta wells.

Production and transportation costs (refer to Financial and Operating Summaries on pages 5 & 6)

Major repairs or a workover in a quarter significantly increase costs per bbl given the small production volumes of the Corporation. This was significant in Q2 as the service rig costs for the two workovers mentioned above totaled approximately $47,000 ($10.45 per bbl).

Winter operating costs are higher than other seasons as certain costs 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.

A significant portion of production costs are fixed and therefore production expense per bbl varies significantly with volume. The increased production in Q4 10 should reduce production costs per bbl for Q4 10 and beyond.

General and administrative (G&A) (refer to Financial and Operating Summaries on pages 5 & 6)

As production increases as a result of development work and further acquisitions, G&A costs per bbl will reduce significantly as these costs tend to be fixed. As the sales volume in the 2010 quarters were in the range of 3,400 to 6,100 bbls, relatively small changes in G&A costs in a quarter have a significant impact on cost per bbl. Legal, accounting, advisory, regulatory and travel expenses were incurred in Q2 10 and Q3 10 related to the property transactions and not all were recorded as transaction costs in property, plant and equipment. There were also costs incurred for the mailings, trustee services and other services related to the annual general and special shareholder meeting and votes in June 2010. These increased costs account for the difference between Q1 10 G&A costs of $101,000 compared to Q2 10 and Q3 10 costs of $149,000 and $136,000 respectively. These increased costs combined with the lower production volumes drove G&A costs per bbl much higher in Q2 10 ($33.21 G&A costs per bbl) and Q3 10 ($39.99 G&A costs per bbl) compared to Q1 10 ($16.59 per bbl).

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

Q4 09 G&A expenses are lower than prior quarters due in part to the capitalizing of general and administrative costs and certain geological costs for the entire year in that quarter. The overhead was capitalized based on standard rates used in the industry.

Interest and financing (refer to Financial and Operating Summaries on pages 5 & 6)

There was no interest expense after Q2 09 as all debt was retired by July 2009. The prior interest expense related to the credit facility with the bank and the note payable. Certain costs were incurred in Q3 2010 to establish the credit facilities including legal fees and fees charged by the bank. No interest was incurred as the Corporation had not yet drawn on the facilities as at September 30, 2010.

Depletion and accretion (D&A) (refer to Financial and Operating Summaries on pages 5 & 6)

Depletion expense is a function of volume produced as it is computed on a "units of production" basis.

The acquisition in Q3 10 added estimated proved reserves of approximately 120,000 bbls and costs of $1.7 million were added to property, plant and equipment, for an acquisition cost of approximately $14.00 per proved bbl. This significantly lowered the average D&A per bbl to $17.37 per bbl in Q3 10, compared to $23.95 per bbl in Q3 09 and $32.21 in Q2 10. The D&A costs per bbl for the nine months ended September 30, 2010 of $22.56 per bbl were comparable to the $27.69 per bbl for the nine months ended September 30, 2009. The favorable property acquisition in August 2010 also explains this decline in 2010 over 2009.

The property acquisition in Q2 10 added $1.7 million of costs to Property, Plant and Equipment and these costs were subjected to depletion. This property addition added only 12,000 bbls to proved reserves which is the volume base on which depletion is computed. This led to the sharp increase in D&A costs in absolute terms and on a per bbl basis between Q1 10 ($18.34 per bbl) and Q2 10 ($32.21 per bbl). Probable reserves for the acquired property were significant. Under International Financial Reporting Standards (IFRS) energy companies may choose the proved plus probable production basis for the computation of depletion. As probable reserves are determined based on a probability of recovery of 50% or more, this broader depletion base under IFRS will generate a more realistic estimate of real depletion. See "New Accounting Standards" herein.

The decrease in volume following the property sale in May 2009 lowered the total expense for depletion and accretion. The sale proceeds, net of the gain, were credited against the accumulated capital costs reducing costs subject to depletion in later quarters. The impact on depletion was greater than 20% and thus a gain was recorded on this disposition as required under Canadian accounting standards for the full cost method.

INCOME TAX

The Corporation had the following tax pools:

Nature of tax pool	Annual Deduction Available-%	September 30, 2010 $000's	December 31, 2009 $000's
Canadian oil and gas property expense (COGPE)	10	2,275	1,156
Canadian development expense (CDE)	30	-	-
Canadian exploration expense (CEE)	100	550	606
Specified foreign exploration & development expense	10	485	525
Undepreciated capital cost (UCC)	25	481	16
Share issue costs	20	32	43
Non capital loss carry forward	100	767	493

The non capital loss carry forward expires in 2027 to 2030. The property sale in 2009 reduced the UCC pool to essentially zero at December 31, 2009.

The Corporation has not recorded any future tax asset or liability, nor has it recorded any tax provision or recovery for 2009 or 2010, due to the uncertainty of the Corporation's ability to fully utilize the available income tax pools against its future income.

"Flow through" common shares were issued in December 2008 and December 2009, required that additional eligible expenditures of $505,000 be incurred by December 31, 2010. This commitment has been met by the date of this MD&A and this amount will be fully renounced by December 31, 2010.

The Corporation 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 Corporation. The Corporation's significant accounting policies are described in notes in the audited financial statements at December 31, 2009 and are discussed in the MD&A for December 31, 2009.

NEW ACCOUNTING STANDARDS

International Financial Reporting Standards

International Financial Reporting Standards ("IFRS") are to be followed by Canadian public companies effective January 1, 2011. Comparative financial statements for 2010 will also be required to follow IFRS. The full cost accounting methods now used by the Corporation is not consistent with IFRS which will require reporting more consistent with successful efforts. The Corporation will finish the following key elements of its plan for the changeover:

- Finalize IFRS accounting policies (now substantially complete) and required additions and amendments to financial disclosure;
- Complete the implementation of the new IFRS compatible oil and gas accounting system which commenced in Q3 10; and
- Review and modify internal controls as necessary.

On July 23, 2009 the IASB adopted certain amendments and exemptions to IFRS 1 in order to make it more useful to Canadian entities adopting IFRS for the first time. One such exemption relating to full cost oil and gas accounting is expected to reduce the administrative burden in transition from the current Canadian Accounting Guideline 16 (related to the full cost method of accounting for oil and gas activities) to IFRS. The amendment permits the Corporation to apply IFRS prospectively to its full cost pool, rather than the retrospective restatement of capitalized exploration and development expenses, with the proviso that an impairment test, under IFRS standards, be conducted at the transition date.

The Corporation has made preliminary decisions regarding IFRS accounting policy alternatives. Western Plains will continue to update its IFRS changeover plan to reflect new and amended accounting standards issued by the International Accounting Standards Board. The nature and quantification of the IFRS impact on the 2010 financial statements of Western Plains Petroleum Ltd. have not yet been fully determined but the general nature and preliminary estimates of certain of the IFRS impacts are provided below.

Preliminary Accounting Policy Choices

Western Plains' significant areas of impact include property, plant and equipment ("PP&E"), assets retirement obligation ("ARO"), impairment testing, and income taxes. These areas of impact have the greatest potential impact to the Corporation's financial statements. The following discussion provides an overview of these areas, as well as the exemptions available under IFRS 1, *First-time Adoption of International Reporting Standards*. In general, IFRS 1 requires first time adopters to retrospectively apply IFRS, although it does provide optional and mandatory exemptions to these requirements. Western Plains is eligible for certain of these exemptions and has chosen to adopt certain exemptions as described below.

Property, Plant and Equipment (PP&E)

Under Canadian GAAP, Western Plains follows the CICA's guidelines on full cost accounting in which all costs directly associated with the acquisition of, the exploration for, and the development of natural gas and crude oil reserves are capitalized into one cost pool as Western Plains operates only in Western Canada. Costs accumulated in this full cost pool are depleted using the unit-of-production method based on proved reserves determined using estimated future prices and costs. Upon transition to IFRS, Western Plains will be required to adopt new accounting policies for each of pre-exploration costs, exploration and evaluation costs and development costs.

Western Plains will adopt the IFRS 1 exemption, which allows the Corporation to deem its January 1, 2010 IFRS PP&E costs to be equal to its Canadian GAAP historical upstream net book value. On January 1, 2010, the IFRS exploration and evaluation costs will be equal to the Canadian GAAP unproved properties balance ($nil for Western Plains) and the IFRS development costs will be equal to the full cost pool balance. Western Plains expects to allocate this full cost pool to the area level cost pools based on the economic valuation (present values based on a 10% discount rate) as determined by the independent reserve evaluator at December 31, 2009.

Pre-exploration costs are those expenditures incurred prior to obtaining legal right to explore and must be expensed as incurred under IFRS. Currently, Western Plains capitalizes and depletes pre-exploration costs within the full cost pool.

> IFRS Impact on the Financial Statements of Western Plains Petroleum Ltd.
> Historically pre-exploration costs were not material to Western Plains and are not material for 2010.

Exploration and evaluation costs (e.g. costs incurred to acquire petroleum and natural gas rights or the costs of drilling exploration wells) are those expenditures for an area or project for which technical feasibility and commercial viability have not yet been determined. Under IFRS, Western Plains will initially capitalize these costs as Exploration and Evaluation assets on the balance sheet. When the area or project is determined to be technically feasible and commercially viable, the costs will be transferred to property, plant and equipment (PP&E). Unrecoverable exploration and evaluation costs associated with an area or project will be expensed.

> IFRS Impact on the Financial Statements of Western Plains Petroleum Ltd.
> Western Plains has initiated development on all of its lands and to date has drilled only development wells on properties for which proved producing reserves had already been assigned by the independent reserve evaluators. The Corporation does not expect to assign any of its petroleum and natural gas properties held on January 1, 2010, or any of is properties currently held, to exploration and evaluation assets.

Development costs include those expenditures for an area or projects where technical feasibility and commercial viability (i.e. producing and other proved reserves have been assigned by the independent reserve evaluator) have been determined. Under IFRS, Western Plains will continue to capitalize these costs within PP&E on the balance sheet. However, the costs will be depleted on a unit-of-production basis over an area level (unit of account) instead of the full cost pool currently utilized under Canadian GAAP.

> IFRS Impact on the Financial Statements of Western Plains Petroleum Ltd.
> Western Plains has made a preliminary decision to establish two development areas being Saskatchewan heavy oil properties and Alberta heavy oil properties. The Saskatchewan and Alberta assets are very similar in terms of geological, engineering, operational, marketing and pricing factors and all are in close geographic proximity to the Corporation's corporate and operational centre in Lloydminster, Alberta. However the different provincial royalty, environment and other regulatory regimes could result in materially different reserve and economic valuations of reserves in the future. Depletion on the unit-of-production method and impairment will be applied on these two areas separately rather than as a single cost centre as is now the case under Canadian GAAP. This change to area level computation of depletion expense is not expected to have a material impact on the depletion expense to be reported under IFRS for 2010.

IFRS allows the Corporation to choose proved plus probable reserves over which capital costs are to be recorded as depletion expense under the units of production method of computing depletion expense, whereas Canadian GAAP prescribes only proved reserves as the reserve base over which capital costs are to be recorded as depletion expense. Upon conversion to IFRS, the Corporation will adopt proved plus probable reserves as the reserve base for the computation of depletion expense on the units of production method.

> IFRS Impact on the Financial Statements of Western Plains Petroleum Ltd.
> This change will materially reduce depletion expense. To illustrate the potential impact, the Corporation had total proved reserves at December 31, 2009 of 121,000 bbls compared to proved plus probable reserves of 490,000 bbls as determined by an independent reserve evaluator. Although other IFRS changes in accounting policies (e.g. lower discount rates will increase asset retirement costs capitalized as property, plant and equipment) will also impact the computation of depletion expense, this four fold increase in the depletable reserves would reduce depletion expense by approximately the same factor.

Under IFRS, divestures of petroleum and natural gas properties will generally result in a gain or loss recognized in net earnings. Under Canadian GAAP, proceeds of divestitures are normally deducted from the full cost pool without recognition of a gain or loss unless the deduction would result in a change to the depletion rate of 20 percent or greater, in which case a gain or loss is recorded.

IFRS Impact on the Financial Statements of Western Plains Petroleum Ltd.
The disposition by Western Plains in Q3 10 did not result in the recording of a gain or loss under Canadian GAAP. However under IFRS the Corporation expects to record a loss on disposal in the financial statements. This immediate recognition of a loss reduces the costs subject to future depletion and consequently future depletion expense will be lower.

Impairment

Under Canadian GAAP, Western Plains is required to recognize an upstream impairment loss if the carrying amount exceeds the undiscounted cash flows from proved reserves for the full cost pool. If an impairment loss is to be recognized, it is then measured at the amount the carrying value exceeds the sum of the fair value (discounted, future, estimated cash flows) of the proved and probable reserves and the costs of unproved properties.

Under IFRS, Western Plains is required to recognize and measure an impairment loss if the carrying value exceeds the recoverable amount for a cash-generating unit (operating assets generating independent cash flows). Under IFRS, the recoverable amount is the higher of fair value less cost to sell and value in use. Impairment losses, other than goodwill, are reversed under IFRS when there is an increase in the recoverable amount.

IFRS Impact on the Financial Statements of Western Plains Petroleum Ltd.
Western Plains will group its PP&E assets into two cash-generating units based on the independence of cash inflows from other assets or other groups of assets. The Corporation has identified Saskatchewan heavy oil assets and Alberta heavy oil assets as its two development areas and each will be considered as a cash generating unit. As provincial government policy can be a significant determinant of cash flows this provincial distinction will determine cash generating units although in every other respect the properties are similar. These two cash generating units were each tested for impairment at January 1, 2010. No impairment was observed which was the same result when the impairment test was applied on the single cost centre basis under Canadian GAAP.

Asset Retirement Obligation (ARO)

Under Canadian GAAP, ARO is measured as the estimated fair value of the retirement and decommission expenditures expected to be incurred and discounted using credit adjusted risk free discount rates. Existing liabilities are not re-measured at each period end using current discount rates. Under IFRS, ARO is measured as the estimate of the expenditures to be incurred and allows the use of current risk free discount rates at each re-measurement date. Western Plains intends to utilize risk free rates rather than credit adjusted risk free rates. The impact of the change in discount rates is recorded as a part of the accretion expense for the period. As a result of Western Plain's intended use of the IFRS 1 assets exemption, the Corporation is required to revalue its January 1, 2010 ARO balance and, recognize the adjustment if any, in retained earnings.

IFRS Impact on the Financial Statements of Western Plains Petroleum Ltd.
Risk free discount rates are lower than the Corporation's credit adjusted risk free rates and therefore the asset retirement obligation under IFRS will be greater than under Canadian GAAP. Since the initial recording of that provision is recorded as an addition to PP&E, that carrying value and depletion expense will be greater under IFRS than under Canadian GAAP.
The asset retirement obligation for Western Plains at December 31, 2009 is estimated to be approximately $338,000 under IFRS compared to $192,000 under Canadian GAAP. The difference of approximately $146,000 will be recorded as an adjustment to retained earnings at January 1, 2010, upon conversion to IFRS

Accretion expense is not material to Western Plains as the total expense in 2010 is estimated to be approximately $15,000 under Canadian GAAP. IFRS accretion expense will not be materially different.

Income Taxes

In transitioning to IFRS, the Corporation's future tax liability will be impacted by the tax effects resulting from the IFRS changes discussed above. Western Plains continues to assess the impact that the IFRS income tax principles may have on the Corporation.

Other IFRS Considerations

Business combinations and join ventures entered into prior to January 1, 2010 will not be retrospectively restated using IFRS principles. One of the significant differences is that transaction costs are expensed rather than recorded as a component of the purchase equation.

> IFRS Impact on the Financial Statements of Western Plains Petroleum Ltd.
> Transaction costs of approximately $126,000 were incurred on property acquisitions in 2010 and were recorded as property, plant and equipment in 2010 and then depleted as part of the full cost base under Canadian GAAP. These costs would be expensed immediately under IFRS. Similarly transaction costs totaling approximately $44,000 were deducted from the proceeds of the Q3 10 disposition and under IFRS the Corporation also expects to record those costs as expense.

Business Combinations

CICA Handbook Section 1582, "Business Combinations" establishes revised principles and requirements for the acquisition method for business combinations and related disclosures. This standard will be adopted prospectively for business combinations for which the acquisition date is after January 1, 2011.

Consolidated Financial Statements

CICA Handbook Section 1601 "Consolidated Financial Statements", together with Section 1602 below, establishes revised principles and requirements for the preparation of consolidated financial statements. This standard will be adopted effective January 1, 2011.

Non-controlling Interests

CICA Handbook Section 1602 "Non-controlling Interests" establishes revised principles and requirements for the accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. The standard requires a non-controlling interest in a subsidiary to be classified as a separate component of equity. In addition, net earnings and components of other comprehensive income are attributed to both the parent and non-controlling interests. This standard will be adopted effective January 1, 2011.

OFF BALANCE SHEET ARRANGEMENTS

The Corporation 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 Corporation or engages in leasing or hedging services with the Corporation.

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 Corporation's results and several of which are beyond control of the Corporation. These business risks are operational, financial or regulatory in nature. These risks and the Corporation's approach to managing these issues are the same as disclosed in the Management Discussion and Analysis for the year ended December 31, 2009. The Corporation does not currently use derivative instruments as a means to manage risk.

RELATED PARTY TRANSACTIONS

The Corporation entered into the following 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:

- Legal services provided by a law firm in which an officer and director is a partner:
    - $163,506 was incurred in the nine months ended September 30, 2010 ($104,479 in the year ended December 31, 2009);
- Various oil field services and products provided by or sold to corporations in which David Forrest, an officer and director of the Corporation, is an officer and a director:
    - $149,048 was incurred for oil field services and products in the nine months ended September 30, 2010 ($278,358 in the year ended December 31, 2009);
    - $36,808 of oil was sold by Western Plains in the nine months ended September 30, 2010 ($nil in the year ended December 31, 2010)
- Oil and natural gas interests ($nil during the year ended December 31, 2009) was acquired in two transactions in the nine months ended September 30, 2010 from a corporation in which David Forrest, an officer and a director of the Corporation, is an officer and director. One transaction was for undeveloped land for cash consideration of $30,000 and the second was for oil and natural gas interests for consideration consisting of 5 million common shares valued at $0.15 per share for a total of $750,000. The latter transaction received shareholder approval. and approval by the TSX Venture Exchange;
- Executive services provided by a corporation in which David Forrest, an officer and a director of the Corporation, is an officer and director:
    - $90,000 was incurred and paid in the nine months ended September 30, 2010 ($120,000 in the year ended December 31, 2009);

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In recent months the Board initiated various controls to monitor the potential for conflicts of interest and the incidence of related party transactions. Initiatives including the appointment of Steven Glover, FCA as Vice President, Finance and Chief Financial Officer, a formal budget approval process and a process to monitor and approve unbudgeted expenditures.

The 2010 financial statements include the following related party transactions in the 2009 comparative amounts, with no balances remaining outstanding at December 31, 2009 or the end of the current period:

- Interest of $80,436 paid to a corporation controlled by David Forrest, an officer and director of the Corporation;
- $53,609 paid to entities controlled by former officers for accounting services.

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 Corporation. 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 Corporation 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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