



Western Plains Petroleum Ltd.

MANAGEMENT'S DISCUSSION & ANALYSIS

Three and Six month periods ended June 30, 2010 and 2009

OVERVIEW OF THE CORPORATION

Western Plains Petroleum Ltd. (the "Corporation" or "Western Plains" or "WPP") 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.

GENERAL

This management discussion and analysis ("MD&A") of Western Plains for the three and six months ended June 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 six months ended June 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 August 24, 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 royalties and operating expenses, and corporate netback, which further deducts 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 (e.g. note payable), 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

In June 2010, the Corporation announced the acquisition of 100% working interests in petroleum and natural gas rights located in the Lloydminster area of Saskatchewan for a purchase price of \$1.5 million with consideration being 10 million common shares.

The new property provides substantial upside drilling opportunities with the first well drilled in July, 2010 through a farm out agreement. The farm out agreement provides that the farmee pay 100% of the capital costs to drill, complete and equip the well. The agreement further provides for a 10% gross overriding royalty (GORR). After the sale of 50% working interests in all oil and gas properties in August 2010, WPP earns half of the GORR (5%). At payout WPP has the option to maintain the 5% GORR or assume a 25% working interest in the well spacing unit.

The above well is currently producing 80 bbls per day (4 net royalty interest to WPP).

The average production for Q2 10 was 49 bbls per day compared to 86 bbls per day for Q2 09. The average production for the six months ended June 30, 2010 was 59 bbls per day compared to 159 bbls per day for the six months ended June 30, 2009. These declines are a result of the sale in May 2009 of a producing (180 bbls per day) property. Nominally or non-producing heavy oil wells acquired in the Lloydminster area of Alberta in the third quarter of 2009, were reactivated to increase production after the sale.

Revenue in 2010 benefited from higher oil prices than the first half of as shown in the "Financial and Operating Summaries". The Corporation averaged approximately \$58.00 per bbl in Q2 10 compared to the average of approximately \$53.00 per bbl in Q2 09. Similarly the first half of 2010 averaged \$62.00 per bbl compared to \$42.00 for the first half of 2009.

OUTLOOK

The Corporation continues to strengthen its financial position with stable production volumes, strong oil prices, control over costs and additional equity from time to time.

Subsequent to the period end, the Corporation sold a 50.0% working interests in all WPP petroleum and natural gas interests located in the Lloydminster area for consideration of \$1.7 million cash. This transaction significantly strengthens the balance sheet and establishes a reputable partner.

Several drilling locations have been identified on the Corporation's land including the property acquired in June 2010. A successful oil well was drilled in July 2010. Drilling, completion and equipping costs per well are budgeted at approximately \$400,000 per well. The Corporation is well positioned to finance additional development from the proceeds of the sale of working interests in July 2010, the well financed and motivated partner and the unused credit facilities (refer to "Liquidity and Capital Resources" of \$1.1 million. Four drilling locations (2 net) have been surveyed and are in the process of being licensed. Drilling will commence in September 2010 with the new wells expected to be on production by mid October 2010.

Current production, following the sale of the 50 % working interests in August 2010, is averaging 45 -50 bbls per day net to WPP.

LIQUIDITY AND CAPITAL RESOURCES

As at June 30, 2010, the Corporation had net debt of \$ 0.3 million (\$0.2 million of net debt at December 31, 2009). In January 2010 Western Plains issued 1,877,500 common shares at a price of \$0.08 per share in a private placement, for gross proceeds of \$150,200 and no finders' fees. In June 10,000,000 million shares were issued to acquire oil and gas interests. No new equity capital has been added subsequent to the period end.

In August 2010 the Corporation entered into 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%. The Corporation has not yet drawn on either credit facility.

As at June 30, 2010, the Corporation had 42,137,274 (30,260,000 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

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	Q2 2010	Q1 2010	Q4 2009	Q3 2009	Q2 2009	Q1 2009	Q4 2008	Q3 2008
Production - total barrels	4,498	6,091	6,294	4,624	7,824	20,529	20,107	12,083
Production - bbls/ day	49	68	68	50	86	228	219	131
Heavy oil revenue	262	394	389	277	411	770	859	1,110
Operating fees earned	26	-	-	-	-	-	-	-
Royalties	(30)	(73)	(49)	(50)	(94)	(172)	(196)	(290)
Production & transportation	(176)	(193)	(161)	(148)	(111)	(258)	(319)	(159)
Operating net back	84	128	179	79	206	340	344	661
General and administrative	(149)	(101)	(51)	(136)	(102)	(155)	(293)	(245)
Interest & financing	-	-	-	-	(58)	(54)	(52)	(52)
Corporate net back	(66)	27	129	(57)	46	131	(1)	364
Depletion & accretion	(145)	(112)	(116)	(111)	(101)	(701)	(671)	(304)
Other (expenses) revenue	(21)	-	-	85**	423*	-	(25)	(11)
Income (loss) for the period	(231)	(85)	12	(83)	368	(570)	(697)	49
Basic and diluted income (loss) per share	(0.007)	(0.003)	0.000	(0.003)	0.017	(0.027)	(0.043)	0.003
*gain on disposition of oil properties								
**gain on settlement of debt								
Royalties as % of petroleum revenue	11	19	13	18	23	22	23	26
Per bbl analysis	Per bbl	Per bbl	Per bbl	Per bbl	Per bbl	Per bbl	Per bbl	Per bbl
Heavy oil revenue	58.31	64.67	61.82	59.88	52.53	37.53	42.74	91.85
Operating fees earned	5.85	-	-	-	-	-	-	-
Royalties	(6.57)	(11.98)	(7.75)	(10.79)	(12.06)	(8.40)	(9.76)	(24.03)
Production and transportation	(39.03)	(31.75)	(25.53)	(32.02)	(14.17)	(12.56)	(15.85)	(13.13)
Operating net back	18.56	20.94	28.55	17.07	26.29	16.57	17.13	54.68
General and administrative	(33.21)	(16.59)	(8.11)	(29.31)	(13.10)	(7.55)	(14.59)	(20.28)
Interest and financing	-	-	-	-	(7.36)	(2.63)	(2.58)	(4.31)
Corporate netback	(14.65)	4.35	20.43	(12.25)	5.83	6.39	(0.04)	30.09
Depletion & accretion	(32.21)	(18.34)	(18.47)	(23.95)	(12.91)	(34.15)	(33.37)	(25.12)
Other (expenses) revenue	(4.58)	-	-	18.42	54.05	-	(1.23)	(0.93)
Income (loss) for the period	(51.44)	(13.99)	1.96	(17.77)	46.97	(27.76)	(34.64)	4.05
WPP revenue prices	58.31	64.67	61.82	59.88	52.53	37.53	42.74	91.85
Benchmark prices								
Edmonton light 40 API	75.46	80.31	76.75	71.70	66.19	50.15	63.94	122.50
Hardisty heavy 12 API	59.67	68.79	64.03	60.90	58.07	39.38	40.62	98.02
Heavy oil differential	15.80	11.52	12.72	10.80	8.13	10.77	23.32	24.48
Funds (invested in) recovered from petroleum properties	(157)	(69)	(212)	(778)	2,703	(50)	(1,784)	(43)

FINANCIAL AND OPERATING SUMMARIES
TABLE B - OPERATIONS FOR THE SIX MONTHS (H1) ENDED JUNE 30, 2010 AND 2009

All production is conventional heavy oil		
\$000's except for Production and per share	H1 2010	H1 2009
Production - total barrels	10,589	28,353
Production - bbls/ day	59	157
Heavy oil revenue	656	1,181
Operating fees earned	26	-
Royalties	(103)	(266)
Production & transportation	(369)	(369)
Operating net back	211	546
General and administrative	(250)	(257)
Interest & financing	-	(112)
Corporate net back	(39)	177
Depletion & accretion	(257)	(802)
Other (expenses) revenue	(21)	423*
Income (loss) for the period	(317)	(202)
Basic and diluted income (loss) per share	(0.010)	
*gain on disposition of oil properties		
Royalties as % of petroleum revenue	16	23
Per bbl analysis	Per bbl	Per bbl
Heavy oil revenue	61.97	41.65
Operating fees earned	2.49	-
Royalties	(9.68)	(9.38)
Production and transportation	(34.84)	(13.01)
Operating net back	19.93	19.26
General and administrative	(23.65)	(9.06)
Interest and financing	-	(3.95)
Corporate netback	(3.72)	6.25
Depletion & accretion	(24.23)	(28.29)
Other (expenses) revenue	(1.95)	14.92
Income (loss) for the period	(29.90)	(7.12)

FINANCIAL AND OPERATING SUMMARIES
TABLE C – BALANCE SHEET

\$000's	Q2 2010	Q1 2010	Q4 2009	Q3 2009	Q2 2009	Q1 2009	Q4 2008	Q3 2008
Net cash (debt)	(334)	(103)	(208)	(377)	174	(2,575)	(2,657)	(1,898)
Total assets	4,242	2,323	2,453	2,297	2,034	4,288	4,820	4,419
Total liabilities	1,120	483	674	783	637	3,258	3,220	2,998
Shareholders equity	3,122	1,840	1,779	1,514	1,397	1,030	1,600	1,421
SHARES 000's								
Basic outstanding	42,137	32,137	30,260	26,907	21,227	21,227	21,227	15,949
Weighted average	33,456	31,929	28,000	26,907	21,227	21,227	17,567	15,949

OPERATING RESULTS FOR 2010

- **Production volumes and revenues (refer to Financial and Operating Summaries on pages 4 & 5)**

Q2 10 production was 49 bbls per day compared to Q2 09 production of 86 bbls per day. H1 10 production was 59 bbls per day compared to H1 09 production of 157 bbls per day. The May 2009 disposal of all producing wells in the Golden Lake and Rush Lake areas of Saskatchewan reduced production by approximately 180 bbls per day. Wells acquired in Q3 09 were reactivated in 2009 with ten (10 net) producing in 2010.

Two wells required workovers in Q2 10 and were shut in for two months prior to and during the workover process. The workovers have been successful and the wells restored to production levels consistent with the prior quarters.

Production by quarter is shown in the “Financial and Operating Summaries” and the variations are explained by these property transactions and the wells off production in Q2 10.

The Corporation plans to increase production on a more diverse property base including the property acquired in Q2 10. The strong balance sheet following the disposition in July 2010, the unused credit facilities and the motivated and well financed partner will allow WPP to drill four wells (2 net) in September 2010. A well drilled by the farm-in partner in July is currently producing 80 bbls per day. The Corporation earns a 5% over-riding royalty until payout and then has the option to convert to a 25% working interest.

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. Unfortunately the heavy oil differential has increased. Essentially that differential widened as the heavy oil price did not follow the recent increases in light oil prices.

- **Royalties (refer to Financial and Operating Summaries on pages 4 & 5)**

The “Financial and Operating Summaries” show royalty expense as a per cent of oil sales to be consistent over the quarters prior to Q3 09. 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.

The production decline and lower prices in Q2 10 compared to Q1 10 reduced the overall royalty burden under the declining scale method of determining Alberta crown royalties. A credit 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 19% in Q1 10

- **Production and transportation costs (refer to Financial and Operating Summaries on pages 4 & 5)**

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.

A significant portion of production costs are fixed and therefore production expense per bbl varies significantly with volume. 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. The plans to drill additional wells to increase production should reduce production costs per bbl for Q4 10 and beyond.

- **General and administrative (refer to Financial and Operating Summaries on pages 4 & 5)**

As production continues to increase as a result of development work and further acquisitions, costs per bbl will reduce significantly as general and administrative costs tend to be fixed. Refer to the plans to increase production on a more diverse property base explained above. As the sales volume in Q1 and Q2 10 were in the range of 4,500 to 6,100 bbls, relatively small changes in general and administrative costs in a quarter have a significant impact on cost per bbl. Legal, accounting, advisory, regulatory and travel expenses were incurred in Q2 10 related to the property transactions. 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 general and administrative costs of \$112,000 compared to Q2 10 costs of \$149,000. These increased costs combined with the lower production drove G&A costs per bbl much higher in Q2 10 (\$33.21) compared to Q1 10 (\$16.59 per bbl). The one time and special costs related to the special shareholder meeting and the acquisition/disposition account for \$9.00 per bbl given the low volume in the quarter.

The Corporation contracts all general and administrative 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 general and administrative 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 4 & 5)**

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.

- **Depletion and accretion (refer to Financial and Operating Summaries on pages 4 & 5)**

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

The property acquisition in Q2 10 added \$1.675 million to Property, Plant and Equipment and these costs were subjected to depletion. This property addition added only 12,000 bbls to proven reserves which is the volume base on which depletion is computed. This led to the sharp increase in depletion costs in absolute terms and on a per bbl basis between Q1 10 (\$18.34 per bbl) and Q2 10 (\$32.21 per bbl) and comparing Q2 10 to Q2 09 (\$12.91 per bbl).

Probable reserves for the acquired property were significant and include five future locations. Under IFRS energy companies may choose this larger 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.

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-%	June 30, 2010 \$000's	December 31, 2009 \$000's
Canadian oil and gas property expense (COGPE)	10	2,369	1,156
Canadian development expense (CDE)	30	14	-
Canadian exploration expense (CEE)	100	606	606
Specified foreign exploration and development expenses	10	499	525
Undepreciated capital cost (UCC)	25	366	16
Share issue costs	20	47	43
Non capital loss carry forward	100	714	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 which require that additional eligible expenditures of \$505,000 be incurred by December 31, 2010. The Corporation renounced expenditures totaling \$285,000 in February 2010 effective December 31, 2009 and expects to renounce \$220,000 in 2011 to be effective December 31, 2010. Eligible expenditures of approximately \$14,000 have been incurred in 2010. If the potential acquisition is closed with the expected effective date of April 12, 2010, WPP will be responsible for the acquired working interest portion of the capital expenditures incurred in the current quarter. Those expenditures net to WPP, include approximately \$50,000 that would be eligible expenditures for flow through purposes. Otherwise the Corporation has significant development plans on the acquired property for the balance of 2010 that will meet this requirement.

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 assess the following key elements as it plans for the changeover:

- determine appropriate changes to accounting policies and required additions and amendments to financial disclosure;
- identify and implement changes in associated processes and information systems; 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 Company to apply IFRS prospectively to its full cost pool, rather than the retrospective assessment 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 which were described in the Management Discussion and Analysis for December 31, 2009. Western Plain's IFRS accounting policies are expected to be finalized in the next quarter. Quantification of IFRS impacts will be determined in 2010 and communication of impacts to external stakeholders will commence in the latter half of 2010. Western Plains will continue to update its IFRS changeover plan to reflect new and amended accounting standards issued by the International Accounting Standards Board.

Expected Accounting Policy Impacts

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 Company'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.

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 pre-exploration costs, exploration and evaluation costs and development costs.

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. In 2008 and 2009, these costs were not material to Western Plains.

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.

Development costs include those expenditures for area or projects where technical feasibility and commercial viability (e.g. producing and other proven 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. Western Plains has not finalized the areas or the inputs to be utilized in the unit-of-production depletion calculation.

Under IFRS, divestitures 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.

Western Plains expects to adopt the IFRS 1 exemption, which allows the Company 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 and the IFRS development costs will be equal to the full cost pool balance. Western Plains will allocate this full cost pool over reserves to establish the area level depletion units.

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. Existing liabilities are not re-measured using current discount rates. Under IFRS, ARO is measured as the estimate of the expenditures to be incurred and requires the use of current discount rates at each re-measurement date. Generally, the change in discount rates results in a balance being added to or deducted from PP&E.

As a result of Western Plain's intended use of the IFRS 1 assets exemption, the Company is required to revalue its January 1, 2010 ARO balance and recognize the adjustment, if any, in retained earnings.

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 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. 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. Western Plains will group its PP&E assets into cash-generating units based on the independence of cash inflows from other assets or other groups of assets.

Income Taxes

In transitioning to IFRS, the Company'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 Company.

Other IFRS 1 Considerations

Business combinations and joint ventures entered into prior to January 1, 2010 will not be retrospectively restated using IFRS principles.

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 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:
 - \$79,404 was incurred in H1 10 (\$104,479 in the year ended December 31, 2009);
- Various oil field services (service rig) and products provided by a corporation in which David Forrest, an officer and director of the Corporation, is an officer and a director:
 - \$91,573 was incurred in the current periods (\$278,358 in the year ended December 31, 2009);
- Oil and natural gas interests (\$nil during the year ended December 31, 2009) was acquired in two transactions in H1 10 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 in the current quarter;
- Executive services provided by a corporation in which David Forrest, an officer and a director of the Corporation, is an officer and director:
 - \$60,000 was incurred and paid in H1 10 (\$120,000 in the year ended December 31, 2009);

The comparative amounts for 2009 include the following related party transactions, 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.

Western Plains Petroleum Ltd.

MANAGEMENT'S DISCUSSION & ANALYSIS

Six months ended June 30, 2010

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