Western Plains Petroleum Ltd.

Financial Statements

December 31, 2011

Management's Report

The financial statements and management's discussion and analysis of Western Plains Petroleum Ltd. (the "Company") are the responsibility of management. The accompanying financial statements have been prepared by management in accordance with the accounting policies in the notes to the financial statements. In the opinion of management, the financial statements have been prepared within acceptable limits of materiality and are in accordance with International Financial Reporting Standards appropriate in the circumstances. The financial information in management's discussion and analysis has been reviewed to ensure consistency with that in the financial statements.

Management maintains appropriate systems of internal control. Policies and procedures are designed and maintained to provide reasonable assurance that assets are safeguarded, transactions are properly authorized, and accounting records are properly maintained to provide reliable information for the preparation of financial statements.

MNP LLP, an independent firm of Chartered Accountants was appointed by the Company's shareholders to conduct an audit of the financial statements. Their examination included such tests and procedures as they considered necessary to provide reasonable assurance that the financial statements are presented fairly in accordance with International Financial Reporting Standards.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal controls. It exercises its responsibilities primarily through the Audit Committee which meets quarterly with management and annually with the independent auditors to review the activities of each.

The Audit Committee has reviewed the financial statements and recommended their acceptance to the Board of Directors. The Board has approved the financial statements for issuance to the shareholders.

David Forrest
President, Chief Executive Officer and Director

Steven Glover
Vice President, Finance and Chief Financial Officer

April 27, 2012

To the Shareholders of Western Plains Petroleum Ltd.:

We have audited the accompanying consolidated financial statements of Western Plains Petroleum Ltd. (the "Company"), which comprise the statements of financial position as at December 31, 2011, December 31, 2010 and January 1, 2010, and the statements of comprehensive loss, changes in shareholders' equity, and cash flows for the years ended December 31, 2011 and December 31, 2010, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for Financial Statements
Management is responsible for the preparation and fair presentation of these financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility
Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance whether the financial statements are free of material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes assessing the appropriateness of accounting principles used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe the audit evidence obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion
In our opinion, the financial statements present fairly, in all material respects, the financial position of Western Plains Petroleum Ltd. as at December 31, 2011, December 31, 2010 and January 1, 2010, and their financial performance and cash flows for the years ended December 31, 2011 and December 31, 2010 in accordance with International Financial Reporting Standards.

Emphasis of Matter
Without qualifying our opinion, we draw attention to Note 1 of the financial statements which indicates that the Company as at December 31, 2011 had accumulated deficit of $3,146,582 and net debt of $1,947,284. These conditions indicate the existence of a material uncertainty which may cast doubt about the Company's ability to continue as a going concern.

MNP LLP

Calgary, Alberta
April 27, 2012

Chartered Accountants

Suite 300, 622 – 5th Ave. S.W., Calgary, Alberta T2P 0M6 (403) 263-3385 Fax: (403) 269-8450

MNP

Western Plains Petroleum Ltd.
Statement of Financial Position
As at December 31, 2011 with comparative figures for 2010
Expressed in Canadian dollars

	Notes	December 31, 2011	December 31, 2010 *(Note 17)*	January 1, 2010 *(Note 17)*
Assets				
Current assets				
Cash and cash equivalents		**-**	390,473	95,962
Trade and other receivables		**1,469,272**	1,394,777	159,454
Subscriptions receivable		**-**	176,400	-
Deposits and prepaid expenses		**45,285**	26,907	18,054
Total current assets		**1,514,557**	1,988,557	273,470
Non-current assets				
Property and equipment	4	**8,019,074**	5,070,587	2,179,216
Exploration & evaluation assets	5	**-**	245,774	-
Total non-current assets		**8,019,074**	5,316,361	2,179,216
Total assets		**9,533,631**	7,304,918	2,452,686
Liabilities				
Current liabilities				
Accounts payable and accrued liabilities		**3,336,841**	1,723,756	481,465
Liability for flow through share renouncement	8(a)	**-**	61,000	139,000
Bank debt	6	**125,000**	-	-
Total current liabilities		**3,461,841**	1,784,756	620,465
Non-current liabilities				
Decommissioning provisions	7	**1,139,400**	651,000	337,800
Total liabilities		**4,601,241**	2,435,756	958,265
Equity				
Share capital	8(a)	**7,334,127**	7,334,127	3,502,207
Warrants	8(c)	**-**	54,000	30,000
Contributed surplus		**744,845**	615,845	207,745
Deficit		**(3,146,582)**	(3,134,810)	(2,245,531)
Total equity		**4,932,390**	4,869,162	1,494,421
Total liabilities and equity		**9,533,631**	7,304,918	2,452,686

Going Concern – Note 1
Commitments – Note 12
Related Parties Transactions – Note 15
Subsequent events – Notes 13

See accompanying notes to the financial statements

Approved by the Board of Directors: “Signed David Forrest” “Signed Leigh Stewart”

Western Plains Petroleum Ltd.
Statement of Comprehensive Loss

For the year ended December 31, 2011 with comparative figures for 2010
Expressed in Canadian dollars

	Notes	2011	2010 (Note 17)
Revenue			
Petroleum revenue		**3,631,564**	1,634,373
Expenses			
Royalties		**695,881**	279,827
Production and transportation		**1,578,724**	742,365
General and administrative	4(d)	**731,246**	606,045
Transaction		**75,487**	164,881
Share based compensation	8(b)	**75,000**	408,100
Depletion and depreciation	4(c)	**846,000**	282,000
		4,002,338	2,483,218
Operating loss		**(370,774)**	(848,845)
Gain (loss) on sale of property and equipment	4(a)	**350,000**	(39,604)
Finance expense	9	**(51,998)**	(78,830)
Loss before income taxes		**(72,772)**	(967,279)
Income tax recovery - deferred	11	**61,000**	78,000
Total comprehensive loss attributable to equity holders		**(11,772)**	(889,279)
Basic and diluted loss per share		**(0.00)**	(0.02)
Weighted average common shares outstanding		**55,101,153**	39,606,242

See accompanying notes to the financial statements.

Western Plains Petroleum Ltd.
Statement of Changes in Equity

For the year ended December 31, 2011 with comparative figures for 2010
Expressed in Canadian dollars

	Notes	# of Common Shares (Note 8 (a))	Common Shares (Note 8 (a))	Warrants (Note 8 (c))	Contributed Surplus	Deficit	Total Equity
Balance, January 1, 2010		30,259,774	3,502,207	30,000	207,745	(2,245,531)	1,494,421
Issue of common shares – private placement		2,144,167	190,200	-	-	-	190,200
Issue of common shares – acquisitions		13,328,363	1,999,254	-	-	-	1,999,254
Share issue costs		-	(90,575)	-	-	-	(90,575)
Issue of common shares – flow through		4,280,909	941,800	-	-	-	941,800
Issue of units – common shares and warrants		1,735,000	258,300	54,000	-	-	312,300
Issue of common shares – exercise of warrants		3,352,940	532,941	(30,000)	-	-	502,941
Share-based compensation		-	-	-	408,100	-	408,100
Total comprehensive loss		-	-	-	-	(889,279)	(889,279)
Balance, December 31, 2010	17	55,101,153	7,334,127	54,000	615,845	(3,134,810)	4,869,162
Share-based compensation	8(b)		-	-	75,000	-	75,000
Expiry of warrants			-	(54,000)	54,000	-	-
Total comprehensive loss		-	-	-	-	(11,772)	(11,772)
Balance, December 31, 2011		**55,101,153**	**7,334,127**	**-**	**744,845**	**(3,146,582)**	**4,932,390**

See accompanying notes to the financial statements.

Western Plains Petroleum Ltd.
Statement of Cash Flows

For the year ended December 31, 2011 with comparative figures for 2010
Expressed in Canadian dollars

	Notes	2011	2010 (Note 17)
Cash provided by (used in):			
Operating activities			
Total comprehensive loss		**(11,772)**	(889,279)
Adjustments for:			
Depletion		**846,000**	282,000
(Gain) loss on sale of property and equipment		**(350,000)**	39,604
Income tax recovery - deferred	11	**(61,000)**	(78,000)
Share based compensation		**75,000**	408,100
Loss on decommissioning		**37,192**	-
Finance expense	9	**51,998**	78,830
Decommissioning costs		**(55,792)**	-
Changes in non-cash working capital	10	**1,084,060**	(185,897)
Cash provided by (used in) operating activities		**1,615,686**	(344,642)
Investing activities			
Additions to property and equipment		**(3,577,514)**	(2,635,207)
Additions to exploration and evaluation assets		**-**	(245,774)
Proceeds from sale of property and equipment	4(a)	**850,000**	1,655,851
Changes in non-cash working capital	10	**471,407**	175,258
Cash used in investing activities		**(2,256,107)**	(1,049,872)
Financing activities			
Proceeds from issue of common shares		**-**	1,947,241
Share issue costs		**-**	(90,575)
Increase in bank loan		**125,000**	-
Interest and finance costs		**(16,198)**	-
Changes in non-cash working capital	10	**141,146**	(167,641)
Cash provided by financing activities		**249,948**	1,689,025
Change in cash		**(390,473)**	294,511
Cash & cash equivalents, beginning of year		**390,473**	95,962
Cash & cash equivalents, end of year		**-**	390,473

See accompanying notes to the financial statements.

1. General business description and going concern

Western Plains Petroleum Ltd. (the “Company” or “Western Plains”) was incorporated under the Business Corporations Act (Alberta) on November 19, 2004. The Company trades under the symbol “WPP” on the TSX Venture Exchange (“TSXV”).

The Company’s address is 202, 5004 – 18th Street, Lloydminster, Alberta T9V 1V4, Canada. The Company engages in the exploration for and the development, production and acquisition of petroleum and natural gas reserves in Western Canada.

These financial statements have been prepared on a going concern basis which contemplates the realization of assets and the payment of liabilities in the ordinary course of business. Should the Company be unable to continue as a going concern, it may be unable to realize the carrying value of its assets and to meet its liabilities as they become due.

The Company’s ability to continue as a going concern is dependent upon its ability to attain profitable operations and generate sufficient cash from operating and financing activities to meet the Company’s needs. As at December 31, 2011 the Company had a deficit of $3.1 million (December 31, 2010 - $3.1 million, January 1, 2010 - $2.2 million) and had net debt of $1.9 million (December 31, 2010 – working capital - $0.2 million, January 1, 2010 – net debt $0.3 million). These financial statements do not reflect the adjustments or reclassification of assets and liabilities which would be necessary if the Company were unable to continue as a going concern and therefore be required to realize its assets and liabilities in other than the normal course of business and potentially at amounts significantly different from those recorded in these financial statements.

2. Basis of preparation

(a) Statement of compliance

These financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS"), as issued by the International Accounting Standards Board ("IASB") up to April 27, 2012, being the date of approval of these financial statements by the Board of Directors.

The Company adopted IFRS in accordance with IFRS 1 First-time Adoption of International Financial Reporting Standards ("IFRS 1") with a transition date to IFRS of January 1, 2010. Consequently, the comparative figures for 2010 and the Company's statement of financial position as at January 1, 2010 have been restated from accounting principles generally accepted in Canada ("Canadian GAAP") to comply with IFRS.

The reconciliations to IFRS from the previous Canadian GAAP financial statements are summarized in Note 17. In addition, IFRS 1 allows certain exemptions from retrospective application of IFRS in the opening statement of financial position. Where these have been used, they are explained in Note 17.

(b) Reporting entity

The financial statements of the Company as at and for the years ended December 31, 2011 and 2010 comprise the Company only as it has no subsidiaries or other interests to be consolidated.

(c) Basis of measurement

The financial statements have been prepared on the historical cost basis except for derivative financial instruments and held for trading financial assets which are measured at fair value with changes in fair value recorded in earnings.

The methods used to measure fair values are discussed in Note 3.

(d) Functional and presentation currency

These financial statements are presented in Canadian dollars, which is the Company's functional currency.

(e) Use of estimates and judgments

The preparation of financial statements requires management to make estimates and use judgment regarding the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities as at the date of the statement of financial position and the reported amounts of revenues and expenses during the year. By their nature, estimates are subject to measurement uncertainty and changes in such estimates in future periods could require a material change in the financial statements. Accordingly, actual results may differ from the estimated amounts as future confirming events occur. Adjustments are recorded in the current period as they become known.

Significant estimates and judgments made by management in the preparation of these financial statements are as follows:

Amounts recorded for depletion and depreciation and amounts used for impairment calculations are based on estimates of petroleum and natural gas reserves. By their nature, the estimates of reserves, including the estimates of future prices, costs, discount rates and the related future cash flows, are subject to measurement uncertainty. Accordingly, the impact to the financial statements in future periods could be material.

Amounts recorded for decommissioning provisions and the related accretion expense requires the use of estimates with respect to the amount and timing of decommissioning expenditures. Other provisions are recognized in the period when it becomes probable that there will be a future cash outflow.

The estimated fair values of derivative financial instruments resulting in financial assets and liabilities, by their very nature, are subject to measurement uncertainty. The collectability of accounts receivable requires judgment which by its very nature creates measurement uncertainty.

Share-based compensation expense requires the estimation of the ultimate payout using the Black-Scholes model which is based on significant assumptions such as volatility, forfeiture, dividend yield and expected term.

Tax interpretations, regulations and legislation in the various jurisdictions in which the Company operates are subject to change. As such, income taxes are subject to measurement uncertainty.

3. Significant accounting policies

The accounting policies set out below have been applied consistently to the years presented in these financial statements, and have been applied consistently by the Company.

(a) Jointly controlled assets

The Company’s petroleum and natural gas activities consist of jointly controlled assets. The financial statements include the Company’s share of these jointly controlled assets and a proportionate share of the relevant revenue and related operating and capital costs.

(b) Property and equipment

Property and equipment is carried at cost less accumulated depletion and depreciation and accumulated impairment losses. The cost of development and production assets includes: transfers from exploration and evaluation assets, which generally include the costs to drill the well and the costs of the associated land upon determination of technical feasibility and commercial viability; the cost to complete and tie-in the wells; facility cost; the cost of recognizing provisions for future decommissioning costs; geological and geophysical costs; and directly attributable overheads. Evaluation and exploration assets are grouped into cash-generating units for impairment testing.

When significant parts of an item of property and equipment, including oil and natural gas assets, have different useful lives, they are recorded and depleted or depreciated as separate components.

Gains and losses on disposal of an item of property and equipment, including oil and natural gas assets, are determined by comparing the proceeds from disposal with the carrying amount of property and equipment and are recognized separately from operating revenues and expenses in earnings.

Exchanges of development and production assets (swaps or farm-ins) are measured at fair value unless the exchange transaction lacks commercial substance or the fair value of neither of the swapped assets can be reliably measured. The cost of the acquired asset is measured at the fair value of the asset given up, unless the fair value of the asset received is more clearly evident. Any gain or loss on derecognition of the asset given up is recognized in the statement of comprehensive income.

Subsequent costs

Costs incurred subsequent to the determination of technical feasibility and commercial viability and the costs of replacing parts of property and equipment are recognized as oil and natural gas assets only when they increase the future economic benefits embodied in the specific asset to which they relate. All other expenditures are expensed as incurred. Such capitalized oil and natural gas assets generally represent costs incurred in developing proved and probable reserves and bringing in or enhancing production from such reserves, and are accumulated on a field or geotechnical area basis. The carrying amount of any replaced or sold component is derecognized. The costs of the day-to-day servicing of property and equipment are expensed as incurred.

Depletion

The net carrying value of the development and production assets is depleted using the unit of production method based on estimated proved and probable reserves, taking into account estimated future development costs necessary to bring those reserves into production. These reserves are estimated by independent reserve evaluators at least annually.

Depreciation

Office assets are depreciated over 5 years on a straight line basis. Leasehold improvements are depreciated over the remaining life of the office lease.

Impairment

The carrying amounts of property and equipment are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, the estimated recoverable amount is calculated. For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets (the "cash-generating unit" or CGU). The recoverable amount of an asset or a CGU is the greater of its value in use or fair value less costs to sell.

Fair value less cost to sell is determined as the amount that would be obtained from the sale of a CGU in an arm's length transaction between knowledgeable and willing parties. The fair value less cost to sell of oil and gas assets is generally determined as the net present value of the estimated future cash flows expected to arise from the continued use of the CGU, including any expansion prospects, and its eventual disposal, using assumptions that an independent market participant may take into account. These cash flows are discounted by an appropriated discount rate which would be applied by such a market participant to arrive at a net present value of the CGU.

In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money. Value in use is generally computed by reference to the present value of the future cash flows expected to be derived from production of proved and probable reserves.

An impairment loss is recognized in earnings if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses previously recognized are assessed at each reporting date for any indications that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimates of the carrying amount only to the extent that the assets carrying amount does not exceed the carrying amount that would have been determined, net of accumulated depletion and depreciation, if no impairment loss had been recognized.

(c) Exploration and evaluation expenditures

Pre-license seismic and other costs are expensed as incurred. Exploration and evaluation costs, including the costs of acquiring licenses and exploratory drilling are capitalized as either tangible or exploration and evaluation assets according to the nature of the assets acquired. The costs are accumulated in cost centres by well, field or exploration area pending determination of technical feasibility and commercial viability. The technical feasibility and commercial viability of extracting a mineral resource is considered to be determinable when proved or probable reserves are determined to exist. A review of each exploration license or field is carried out, at least annually, to ascertain whether proved or probable reserves have been attributed by the independent reserve evaluator. Upon determination of proved or probable reserves, exploration and evaluation assets attributable to those reserves are first tested for impairment and then reclassified from exploration and evaluation assets to oil and natural gas assets with property and equipment.

Exploration and evaluation assets are assessed for impairment if (i) sufficient data exists to determine technical feasibility and commercial viability, and (ii) facts and circumstances suggest that the carrying amount exceeds the recoverable amount. For purposes of impairment testing, exploration and evaluation assets are allocated to cash-generating units.

For exchanges (swaps or farm-ins) or parts of exchanges that involve only capitalized exploration and evaluation costs, the exchange is accounted for at cost.

(d) Decommissioning provisions

An obligation to incur restoration, rehabilitation and environmental costs arises when environmental disturbance is caused by the exploration, development or ongoing production of petroleum and natural gas properties.

A decommissioning provision is recognized as a liability for obligations associated with the abandonment of petroleum and natural gas wells, removal of equipment from leased acreage and returning such land to its original condition as set by standards of environmental regulations.

The Company records the fair value of each decommissioning obligation in the period a well or related asset is drilled, constructed or acquired. Decommissioning obligations are measured at the present value of management’s best estimate of the expenditure required to settle the present obligation at the date of the statement of financial position. Provisions are determined by discounting the expected future cash flows at a pre-tax risk-free rate. The expected future cash flows reflect current market assessments and the risks specific to the liability.

The obligation is reviewed regularly by the Company's management based on current regulations, costs, technologies and industry standards. The discounted obligation is initially capitalized as part of the carrying amount of the related property and equipment or exploration and evaluation assets, and a corresponding liability is recognized. The increase in oil and natural gas assets is depleted on the same basis as the related petroleum and natural gas component, while the liability is accreted as finance expense in earnings, until it is settled or sold. Subsequent to the initial measurement, the

obligation is adjusted at the end of each period to reflect the passage of time, changes in the estimated future cash flows underlying the obligation and changes in the pre-tax risk-free rate. Estimated future decommissioning cash flows are estimated based on estimated current decommission costs adjusted to the future expected decommissioning date by applying an estimate of inflation.

The increase in the provision due to the passage of time is recognized as finance costs whereas increases/decreases due to changes in the estimated future cash flows or changes in the risk free rate are capitalized. Actual costs incurred upon settlement of the decommissioning provisions are charged against the provision to the extent the provision was established.

(e) Revenue

Revenue from the sale of petroleum and natural gas is recognized based on volumes delivered to petroleum purchasers at contractual delivery points and prices paid by the petroleum purchasers.

The costs associated with the delivery, including operating and maintenance costs, transportation and production based royalty expenses are recognized in the same period in which the related revenue is earned and recorded.

Royalty income is recognized as it accrues in accordance with the terms of the overriding royalty agreements.

(f) Financial instruments

Non-derivative financial instruments

Non-derivative financial instruments comprise cash, accounts receivable, bank debt, accounts payable and accrued liabilities. Non-derivative financial instruments are recognized initially at fair value net of any direct attributable transaction costs. Subsequent to initial recognition non-derivative financial instruments are measured as described below.

Cash and Cash Equivalents

Cash and cash equivalents include bank balances and highly liquid temporary money market instruments with original maturities of three months or less.

Financial assets at fair value through profit or loss

An instrument is classified at fair value through profit or loss if it is held for trading or is designated as such upon initial recognition. Financial instruments are designated at fair value through earnings if the Company manages such investments and makes purchase and sale decisions based on their fair value in accordance with the Company's risk management or investment strategy. Upon initial recognition related transaction costs are expensed as incurred. Financial instruments at fair value through earnings are measured at fair value, and changes therein are recognized in earnings.

Compound instruments

Compound instruments are separated into their liability and equity components using the effective interest rate method. The liability component accretes up to the principal balance at maturity. The equity component will be reclassified to share capital on conversions. Any balance in equity that remains after the settlement of the liability is transferred to contributed surplus. The equity portion is recognized net of deferred income taxes.

Other

Other non-derivative financial instruments, such as accounts receivable, bank debt, accounts payable and accrued liabilities, are measured at amortized cost using the effective interest method, less any impairment losses.

Derivative financial instruments

The Company may enter into financial derivative contracts in order to manage the exposure to market risks from fluctuations in commodity prices. These instruments would not be used for trading or speculative purposes. All financial derivative contracts would be classified as fair value through earnings and recorded on the statement of financial position at fair value. Transaction costs are expensed as incurred.

Embedded derivatives are separated from the host contract and accounted for separately if the economic characteristics and risks of the host contract and the embedded derivative are not closely related, a separate instrument with the same terms as the embedded derivative would meet the definition of a derivative, and the combined instrument is not measured at fair value through earnings. Changes in the fair value of separable embedded derivatives are recognized in earnings.

Share Capital

Common shares are classified as equity. Costs directly attributable to the issue of shares are recognized as a deduction from equity.

(g) Income taxes

Income tax expense is comprised of current and deferred tax. Income tax expense is recognized in the statement of comprehensive loss except to the extent that it relates to items recognized directly in equity, in which case it is recognized in equity.

Current tax is the expected tax payable on the taxable income for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognized on the temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax is not recognized on the initial recognition of assets or liabilities in a transaction that is not a business combination. In addition, deferred tax is not recognized for taxable temporary differences arising on the initial

recognition of goodwill. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date. Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset, and they relate to income taxes levied by the same tax authority on the same taxable entity, or on different tax entities, but they intend to settle current tax liabilities and assets on a net basis or their tax assets and liabilities will be realized simultaneously.

A deferred tax asset is recognized to the extent that it is probable that future taxable profits will be available against which the temporary difference can be utilized. Deferred tax assets are reviewed at each reporting date and are reduced to the extent that is no longer probable that the related tax benefit will be realized.

(h) Accounting standards issued not yet applied

Presentation of Financial Statements

In June 2011, the IASB issued amendment to IAS 1 requiring items within other comprehensive income that may be reclassified to the profit or loss section of the statement of operations to be grouped together. The amendments are to be applied retrospectively and will be effective for annual periods commencing on or after July 1, 2012, with earlier implementation permitted. The amendment will have no impact on the Company after implementation.

Financial Instruments

The IASB intends to replace IAS 39, “Financial Instruments: Recognition and Measurement” (“IAS 39”) with IFRS 9, “Financial Instruments” (“IFRS 9”). IFRS 9 will be published in three phases, of which the first phase has been published.

For financial assets, IFRS 9 uses a single approach to determine whether a financial asset is measured at amortized cost or fair value, and replaces the multiple rules in IAS 39. The approach in IFRS 9 is based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. The new standard also requires a single impairment method to be used. For financial liabilities, the approach to the fair value option may require different accounting for changes to the fair value of a financial liability as a result of changes to an entity’s own credit risk.

IFRS 9 is currently effective for annual periods beginning on or after January 1, 2013. However, the IASB has published an exposure draft which proposes to extend the mandatory effective date to January 1, 2015. There will be no significant impact to the Company upon implementation of the published standard.

Joint Arrangements

IFRS 11, “Joint Arrangements”, issued on May 12, 2011, will replace IAS 31, “Interest in Joint Ventures”. The Standard is effective for annual periods beginning on or after January 1, 2013. The new standard redefines joint operations and joint ventures and requires joint operations to be proportionately consolidated and joint ventures to be equity accounted. Under IAS31, joint ventures could be proportionately accounted. The Company is currently evaluation the impact of IFRS 11 but believes all of its joint arrangements meet the definition of joint operations and will continue to be proportionately consolidated.

Fair Value Measurements

The IASB issued IFRS 13, “Fair Value Measurement” which provides a consistent and less complex definition of fair value, establishes a single source of guidance for determining fair value and introduces consistent requirements for disclosures related to fair value measurement. Prospective application of this standard is effective for fiscal periods beginning on or after January 1, 2013, with early adoption permitted. The Company is currently assessing the impact of this standard.

4. Property and equipment

	Oil & Natural Gas Assets	Office Assets	Total
Cost			
Balance, January 1, 2010	2,179,215	-	2,179,215
Additions	4,678,606	-	4,678,606
Decommissioning provisions	553,470	-	553,470
Dispositions	(2,058,704)	-	(2,058,704)
Balance, December 31, 2010	5,352,587	-	5,352,587
Additions	3,530,467	46,846	3,577,313
Transfer from exploration & evaluation assets	245,774	-	245,774
Decommissioning provisions	635,400	-	635,400
Dispositions	(664,000)	-	(664,000)
Balance, December 31, 2011	9,100,228	46,846	9,147,074
Accumulated depletion			
Balance, January 1, 2010	-	-	-
Depletion and depreciation	(282,000)	-	(282,000)
Balance, December 31, 2010	(282,000)	-	(282,000)
Depletion and depreciation	(838,000)	(8,000)	(846,000)
Balance December 31, 2011	(1,120,000)	(8,000)	(1,128,000)
Net book value			
Balance, January 1, 2010	2,179,215	-	2,179,215
Balance, December 31, 2010	5,070,587	-	5,070,587
Balance, December 31, 2011	7,980,228	38,846	8,019,074

(a) Dispositions

In 2011 the Company entered into two separate purchase and sale agreements. Disposition 1 was for the sale of a 36% working interest in a producing property for cash consideration of $450,000. Disposition 2 was for the sale of the Company's 50% working interest in a well which was sold to the joint venture partner for cash consideration of $400,000. This was a related party transaction (Note 15). The dispositions comprised the following:

	Disposition 1	Disposition 2
Cash consideration	450,000	400,000
Decommissioning provision	144,000	20,000
	594,000	420,000
Carrying value of property and equipment	(478,000)	(186,000)
Gain on sale	116,000	234,000

In 2010 the Company entered into one purchase and sale agreement. The transaction was for the disposition of a 50% working interest in all the producing properties of the Company at that time (effective July 1, 2010) for cash consideration of $1,700,000. The disposition comprised the following:

	Disposition
Cash consideration	1,700,000
Decommissioning provision	319,100
	2,019,100
Net carrying value of property & equipment sold	(2,058,704)
Loss on sale	(39,604)

(b) Acquisitions

In 2011 the Company acquired oil and natural gas assets pursuant to a purchase and sale agreements as follows:

	Acquisition
Net assets:	
Property and equipment	1,230,000
Decommissioning obligation	(476,000)
	754,000
Consideration:	
Cash	232,000
Vendor debt assumed	522,000
	754,000

In 2010, the Company acquired oil and natural gas assets pursuant to a purchase and sale agreement as follows:

Net assets:	Acquisition 1	Acquisition 2
Property and equipment	1,757,600	1,626,902
Decommissioning obligation	(257,600)	(147,000)
	1,500,000	1,479,902
Consideration:		
Cash	-	685,895
Common shares issued	1,500,000	499,254
Vendor debt assumed	-	294,753
	1,500,000	1,479,902

(c) Depletion and impairment

The depletion cost base includes future development costs of $3,085,000 ($1,800,000 at December 31, 2010) and has excluded salvage value of equipment of $967,500 ($700,000 at December 31, 2010).

At December 31, 2011, the Company tested its cash-generating units for impairment. The recoverable amount of the cash-generating unit was estimated based on the higher of the value in use and the fair value less costs to sell. The estimate of fair value less costs to sell was determined using a discount rate of 10 percent and forecasted cash flows, with escalating prices and future development costs, as obtained from an independent reserves evaluator for the Company's proved plus probable reserves. The forecast prices used to estimate the fair value less cost to sell are those used by the independent reserves evaluators

No petroleum and natural gas property cash-generating units were considered impaired as at or during the years ended December 31, 2011 and 2010.

The impairment test was based on the following future prices at December 31, 2011 of the Company's independent reserve evaluator:

Year	Petroleum Heavy oil - Bow River at Hardisty ($CDN/bbl.)
2012	76.40
2013	75.70
2014	74.00
2015	76.00
2016	78.10
2017	80.20
2018	82.35
2019	84.55
2020	86.80
2021	89.10

Increases after 2021 approximate 2% per year. Adjustments were made to these benchmark prices, for purposes of the impairment test, to reflect varied delivery points and quality differentials in the Company's products.

(d) Capitalized general and administrative and interest costs

The Company has not capitalized any general and administrative expenses or interest during the years ended December 31, 2011 or 2010.

5. Exploration and evaluation assets

	Continuity
Cost	
Balance, January 1, 2010	-
Additions	245,774
Balance, December 31, 2010	245,774
Transfers to property and equipment	(245,774)
Balance, December 31, 2011	-

Exploration and evaluation assets at December 31, 2010 consist of the Company's projects which were pending production or the determination of proved reserves. Production commenced on these properties in 2011 and therefore the amounts were transferred to property and equipment after testing that there was no impairment.

(a) Depletion and impairment charge

Exploration and evaluation assets are not depleted or amortized. Exploration and evaluation assets are aggregated into groups of cash-generating units for the purpose of assessing for impairment. Any impairment of exploration and evaluation assets, and any eventual reversal thereof, is recognized as additional depletion expense. No impairment was recognized during the years ended December 31, 2011 or 2010.

(b) Recoverability of exploration and evaluation assets

The Company assesses the recoverability of exploration and evaluation assets, before and at the moment of reclassification to property and equipment, using cash-generating units. The cash-generating unit includes both the exploration and evaluation cash-generating unit and the property and equipment cash-generating units related to oil and natural gas assets for that area that the exploration and evaluation assets are being transferred into.

(d) Capitalized general and administrative and interest costs

The Company has not capitalized any general and administrative expenses or interest during the years ended December 31, 2011 or 2010.

6. Bank debt

In October 2010 the Company entered into an agreement with a Canadian chartered bank for lines of credit, which are payable on demand and secured by a $25,000,000 debenture and general security agreement on all assets of the Company.

In September 2011 the revolving line of credit increased to $1,000,000 from $800,000 following the regularly scheduled annual review. An interim review of the facility limits commenced in November 2011. In February 2012 the bank increased the facility limit to $2,200,000.

This revolving credit facility bears interest at prime plus 1.5%. As at December 31, 2011, the Company had drawn $125,000 ($nil at December 31, 2010) and was in compliance with all covenants except the requirement to maintain a working capital ratio as defined by the bank of at least 1:1. The actual ratio at December 31, 2011 was 0.72:1 (1.15:1 at December 31, 2010). The bank waived the breach in light of the subsequent increase in the facility limit which would have resulted in a working capital ratio of 1.1:1 had it been in place at December 31, 2011.

The Company also has available a development line of credit for an amount up to $300,000 and is subject to various standard covenants. This demand credit facility bears interest at prime plus 2.0%. The Company has not drawn on the available facility as at or during the years ended December 31, 2011 or 2010.

7. Decommissioning provisions

The future decommissioning obligations were determined by management and were based on the Company's net ownership interest, the estimated future costs to reclaim and abandon the wells, and the estimated timing of when the costs will be incurred.

The following accounts for the continuity of the decommissioning provisions:

	Continuity
Balance, January 1, 2010	337,800
Liabilities incurred or acquired	512,600
Liabilities settled or disposed	(319,100)
Change of estimate	40,870
Accretion	78,830
Balance, December 31, 2010	651,000
Liabilities incurred or acquired	840,800
Liabilities settled or disposed	(182,200)
Change of estimate	(205,400)
Accretion	35,200
Balance, December 31, 2011	1,139,400

All of these obligations are estimated to be incurred in 2019 to 2031 and will be funded from general Company resources at that time of retirement. The undiscounted, inflation adjusted total future liability to settle the obligation as at is estimated to be $1.8 million (December 31, 2010 - $1.1 million, January 1, 2010 $0.6 million) which has been discounted using a risk free rate of 2.41% at December 31, 2011 (4.0% at December 31, 2010). The range of discount rates used in 2011 was 2.41% to 4.0% (3.27% to 4.08% - 2010).

An inflation rate of 1.5% was used at December 31, 2011 to estimate the decommissioning costs at the estimated future abandonment and reclamation dates. An inflation rate of 2% was used throughout the preceding periods in 2011 and in prior years. The 1.5% inflation rate is considered more appropriate for the current circumstances and consistent with industry peers. The impact of this change was a reduction in the decommissioning liability of $137,000 with a corresponding decrease in property and equipment.

8. Share Capital

(a) Authorized - Unlimited number of Common shares

Each shareholder is entitled to one vote and shall be entitled to receive non-cumulative dividends if, and when, declared by the Board of Directors.

In 2010 flow through shares were issued for proceeds of $941,800 which was classified entirely as equity as there was no premium over the fair value of the common shares issued. Had there been a premium at the date of issue that premium would have been recorded as a liability based on the excess of the issue price over the fair value of the share. The commitment to incur eligible expenditures was met in 2010 and 2011 with the latter under the lookback provisions of the Income Tax Act (Canada).

In 2008 flow through shares were issued for proceeds of $500,000 for which the commitment was met on a prospective basis. The excess over fair value amounted to $139,000 which was recorded as a liability at the date of transition to IFRS of January 1, 2010. This liability was met in 2010 for the amount of $78,000 and in 2011 for the amount of $61,000.

(b) Stock option plan

The Company established a Stock Option Plan (“Plan”) for directors, officers, employees and service providers. The maximum number of common shares which may be reserved under the Plan may not exceed 10% of the outstanding common shares at that time. Options granted under the plan generally have a term of five years and vest on the date of grant. The exercise price of each option equals or exceeds the market price of the Company’s common shares on the date of grant.

The following accounts for the continuity of the stock options:

	# of options	Weighted Average Price
Balance, January 1, 2010	1,452,000	0.14
Granted	3,100,000	0.18
Expired	(400,000)	0.20
Balance, December 31, 2010	4,152,000	0.16
Granted	**1,000,000**	0.11
Expired	**(192,000)**	0.30
Balance, December 31, 2011	**4,960,000**	**0.15**

Expiry	Weighted Average Remaining Life (Years)	Exercise Price	Outstanding and Exercisable
March 2013	1.20	$0.11	260,000
July 2013	1.56	$0.14	150,000
December 2013	1.96	$0.10	600,000
June 2015	3.48	$0.15	1,400,000
December 2015	3.96	$0.21	1,550,000
October 2016	4.82	$0.11	1,000,000
			4,960,000

All options issued in 2011 and 2010 vested immediately. The fair value of the options granted in 2011 was $75,000 ($408,100 in 2010). The fair value of options was determined using the following assumptions:

	2011	2010
Risk free interest rate (%)	1.31	1.28%
Expected volatility (%)	88%	88%
Expected life (in years)	5 years	5 years
Expected dividends	-	-
Forfeiture rate	0%	0%

(c) Warrants

The warrants issued in 2010 carried an exercise price of $0.25 per common share and expired in December 2011. The fair value of the warrants was estimated to be $54,000 in 2010 using the Black-Scholes option pricing model assuming a risk free interest rate of 1.25%, volatility of 88%, a one year life and with no expected dividends.

The following accounts for the continuity of warrants:

	# of warrants	Exercise Price
Balance, January 1, 2010	3,352,940	0.15
Issued	867,500	0.25
Exercised	(3,352,940)	0.15
Expired	-	-
Balance, December 31, 2010	867,500	0.25
Expired	(867,500)	0.25
Balance, December 31, 2011	-	-

9. Finance expense

Year ended December 31	2011	2010
Fees and other costs on bank debt	(6,591)	-
Interest on bank debt	(10,207)	-
Accretion of decommissioning provisions	(35,200)	(78,830)
Finance expense	(51,998)	(78,830)

10. Supplemental cash flow information

Changes in non-cash working capital are comprised of:

Year ended December 31	2011	2010
Cash provided by (used in):		
Trade and other receivables	(74,496)	(1,235,322)
Subscriptions receivable	176,400	(176,400)
Deposits and prepaid expenses	(18,378)	(8,853)
Accounts payable and accrued liabilities	1,613,086	1,242,295
Changes in non-cash working capital	1,696,613	(178,280)
Cash provided by (used in):		
Operating activities	1,084,060	(185,897)
Investing activities	471,407	175,258
Financing activities	141,146	(167,641)
Changes in non-cash working capital	1,696,613	(178,280)

Property and equipment acquired through the issuance of common shares amounting to $1,999,254 was a non-cash transaction in 2010 and excluded from the statement of cash flows in 2010.

11. Income tax

The recovery of income taxes in 2011 and 2010 relate to the income tax effect of renouncing the Company's income tax expenditures to investors as a condition of issuing flow through shares. The income tax recovery in 2011 and 2010 varies from the amounts that would be computed by applying the effective Canadian federal and provincial income tax rates to the loss before income taxes as follows:

	2011	2010
Loss before income taxes	(72,772)	(967,279)
Expected income tax rate	27.5%	28%
Expected income tax recovery	(20,000)	(271,000)
Differences resulting from:		
Share based compensation	20,000	114,000
Income rate affect for deferred taxes	-	17,000
Other	20,000	(43,000)
Changes in deferred tax asset not recognized	(310,000)	42,000
Income tax effect of renouncement of income tax expenditures	229,000	63,000
income tax recovery - deferred	(61,000)	(78,000)

The major components of the unrecognized deferred income asses (liabilities) comprise the temporary differences related to:

	December 31, 2011	December 31, 2010	January 1, 2010
Property and equipment	(627,000)	(149,000)	91,000
Decommissioning provisions	285,000	163,000	84,000
Non-capital losses carried forward	352,000	300,000	112,000
Share issue costs	17,000	23,000	8,000
	27,000	337,000	295,000
Deferred tax asset not recognized	(27,000)	(337,000)	(295,000)
Deferred tax asset (liability)	-	-	-

The non-capital losses for income tax purposes carried forward from the current and prior years expire as follows:

Year	Loss Carry Forward
2023	302,000
2024	110,000
2027	1,000
2028	80,000
2030	537,000
2031	376,000
Total	1,406,000

12. Commitments

In June 2011 the Company entered into a lease for office space with an expiry of August 31, 2013. The minimum lease payments amount to $15,600 for 2012 and $10,400 for 2013.

13. Subsequent events

In February 2012 the Company increased its credit facility limit to $2.2 million from $1.0 million (Note 6).

The Company also 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.

14. Remuneration

The Company operates primarily by contracting personnel either directly as individuals or through controlled corporations (Note 15). During part of 2011 the Company employed one person and has no employees in 2012. No benefits are provided other than those mandated for the single employee. Stock options are provided to the contract personnel and directors. Non-executive directors are paid a fixed honorarium of $3,250 per year plus additional fees if they serve on a special committee.

Year ended December 31	2011	2010
Total wages, fees and short term benefits *	405,407	411,200
Total share based payments *	75,000	408,100
	480,407	819,300

Key management and directors fees and short term benefits	287,458	247,188
Key management and directors share based payments	45,000	308,000
	332,458	555,188

- Includes key management and directors

15. Related party transactions

The Company 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 an employee:
  - $157,395 was incurred in 2011 (2010 - $232,876) of which $17,600 (2010 - $40,272) was in accounts payable and accrued liabilities at December 31, 2011;
  - Costs were recorded as general and administrative expense, share issue costs or as transaction costs depending on the activity for which legal services were provided;
- Various oil field services and products provided by corporations in which an officer and director of the Company is an officer and a director:
  - $304,054 was incurred in 2011 (2010 - $190,633) of which $65,013 (2010 - $nil) was in accounts payable and accrued liabilities at December 31, 2011;
  - Costs were recorded as either production expense or capital expenditures depending on the nature of the expenditure;
- Oil sold to a corporation in which an officer and director of the Company is an officer and a director:
  - $nil was earned in 2011 (2010 - $36,808) of which $nil (2010 - $nil) was in accounts receivable at December 31, 2011;
  - Proceeds were recorded as petroleum revenue;
- Executive services provided by a corporation in which an officer and a director of the Company is an officer and director:
  - $178,000 was incurred in 2011 (2010 - $140,000) for executive services, of which $175,000 was fees and $3,000 was to reimburse travel expenses. $15,309 (2010 - $nil) was in accounts payable and accrued liabilities at December 31, 2011;
  - Costs were recorded as general and administrative expense;
- Certain oil and natural gas properties are held as joint arrangements (working interest partner) with an entity with common management and officers:
  - Two (1.0 net) wells were drilled in 2011 as 50/50 partners pursuant to farm in agreements. Cash calls totalling $400,000 ($nil in 2010) were paid to Western Plains by the working interest partner towards these two wells for which capital costs of $286,527 ($nil in 2010) were incurred and billed to the working interest partner in 2011;
  - 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 (Note 4 (a));
  - Net revenue of $187,138 ($nil in 2010) was received in 2011 on behalf of the working interest partner;
  - $289,235 was in accounts payable and accrued liabilities at December 31, 2011 ($nil at December 31, 2010) related to the above transactions;
- In 2010 $696,187 of oil and natural gas properties were acquired from a corporation in which an officer and director of the Company is an officer and a director. No oil properties were acquired from a related party in 2011.

16. Financial instruments

(a) Risk management

(i) Overview

The Company's activities expose it to a variety of financial risks that arise as a result of its exploration, development, production, and financing activities such as:

- credit risk;
- liquidity risk; and
- market risk.

This note presents information about the Company's exposure to each of the above risks, the Company's objectives and policies and processes for measuring and managing risk. Further quantitative disclosures are included throughout these financial statements.

The Company employs risk management strategies and polices to ensure that any exposure to risk is consistent with the Company's business objectives and risk tolerance levels. While the Board of Directors has the overall responsibility for the establishment and oversight of the Company's risk management framework, management has the responsibility to administer and monitor these risks.

(ii) Credit risk

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligations. Substantially all of the Company's accounts receivable are due from petroleum and natural gas marketers and are subject to normal credit risk.

The maximum exposure to credit risk comprises:

	December 31, 2011	December 31, 2010	January 1, 2010
Cash	-	390,473	95,962
Trade and other receivables	1,469,272	1,394,777	159,454
Subscriptions receivable	-	176,400	-
Maximum exposure to credit risk	1,469,272	1,961,650	255,416

Trade and other receivables

All of the Company's operations are conducted in Canada. The Company's exposure to credit risk is influenced mainly by the individual characteristics of each customer or joint interest partner. Significant changes in industry conditions and risks that negatively impact customers' ability to generate cash flow will increase the risk of not collecting receivables. Management believes the risk is mitigated by the size and reputation of the companies purchasing it oil production.

Due to the small size of the Company, it markets most of its oil production to one marketer. Management monitors the credit rating of the major oil producer to minimize credit risk. Receivables from petroleum and natural gas marketers are normally collected on the 25th day of the month following production. The entire receivable listed below for oil revenue was collected subsequent to December 31, 2011.

The Company did not have an allowance for doubtful accounts as at December 31, 2011 or 2010 and did not provide for any doubtful accounts nor was it required to write-off any receivables during the year ended December 31, 2011. When determining whether past due accounts are collectible, the Company factors in the past credit history of the counterparties.

The Company considers all amounts greater than 90 days as past due of which there was $337,942 ($nil at December 31, 2010) past due at December 31, 2011 from joint venture partners and others. For the amounts due from joint venture partners, the Company will apply net revenues otherwise attributable to those partners against the amounts owed until fully recovered.

Also included in trade and other receivables is an amount of $115,500 related to a property acquisition (Note 4 (b)). Property taxes on the acquired property related to prior years were not paid by the vendor. The Company recorded this liability and an offsetting receivable. The vendor of the property has been served with a statement of claim and discussions have occurred regarding settlement. Management is confident the amount is collectable.

The Company's trade and other receivables comprised the following:

	December 31, 2011	December 31, 2010	January 1, 2010
Oil revenue	926,872	720,352	112,162
Joint venture partners	420,669	581,548	1,593
Refundable GST	-	92,877	-
Other	121,731	-	45,699
Trade and other receivables	1,469,272	1,394,777	159,454

Cash and cash equivalents

The Company manages the credit exposure related to cash by selecting financial institutions with high credit ratings. Given these credit ratings, management does not expect any counterparty to fail to meet its obligations.

(iii) Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they are due. The Company manages its bank debt, cash inflows from operations and capital expenditures to ensure it will have sufficient liquidity to meet its liabilities when due. The Company's ongoing liquidity is impacted by various external events and conditions, including commodity price fluctuations and the global economic environment.

The Company's financial liabilities consist of accounts payable and accrued liabilities and bank debt. Accounts payable consists of invoices payable to trade suppliers for general, administrative, royalty, production and capital expenditures and are usually payable in 30 to 90 days.

By nature, the petroleum and natural gas industry is very capital intensive. As a result, the Company prepares annual capital expenditure budgets and utilizes authorizations for expenditures to manage capital expenditures. Refer to Note 16(b) for further disclosure on the management of capital.

The following table indicates the contractual maturities for financial liabilities as at December 31, 2011:

	1 year	Beyond 1 year	Total
Accounts payable & accrued liabilities	3,336,841	-	3,336,841
Bank debt	125,000	-	125,000
Total	3,461,841	-	3,461,841

The Company expects the bank debt to be renewed by the bank following the next review scheduled for June 2012 (Note 6).

(iv) Market risk

Changes in market prices, such as commodity prices, interest rates and foreign exchange rates create market risk and impact cash flows, earnings and the fair value of financial instruments (Note 16 (c)). The Company manages and mitigates market risk within acceptable limits, while maximizing returns.

Commodity price risk

The nature of the Company's operations results in exposure to fluctuations in commodity prices. Commodity prices for petroleum and natural gas are impacted by global economic and political events that dictate the levels of supply and demand. Management continuously monitors commodity prices and may consider instruments to manage exposure to these risks when it deems appropriate. The Company did not enter into any derivative financial contracts during the years ended December 31, 2011 or 2010 nor does it currently have any derivative financial contracts.

The Company's production is usually sold using "spot" or near term contracts, with prices fixed at the time of transfer of custody or on the basis of a monthly average market price. The Company may hedge some petroleum and natural gas sales through the use of various financial derivative forward sales contracts or physical sales contracts when deemed appropriate.

A 10% difference in oil prices for the year ended December 31, 2011 would have increased or decreased petroleum revenue by $363,000 depending on the direction of the difference. Royalties would also have increased or decreased accordingly for a net impact on the operating loss of approximately $283,000.

Foreign currency risk

Prices for petroleum are determined in global markets and generally denominated in United States dollars. The Company had no forward exchange rate contracts in place nor any working capital items denominated in foreign currencies as at or during the years ended December 31, 2011 or 2010. An increase in the value of the Canadian dollar relative to the U.S. dollar decreases the revenues received from the sale of petroleum and natural gas commodities. Correspondingly, a decrease in the value of the Canadian dollar relative to the U.S. dollar increases the revenues received from the sale of petroleum and natural gas commodities. The impact of such exchange rate fluctuations cannot be accurately quantified.

Interest rate risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Company has interest bearing bank debt. Consequently, the Company is exposed to interest rate risk. Changes in interest rates also affect the general economy. The Company had no interest rate swaps or financial contracts in place as at or during the years ended December 31, 2011 or 2010. A 1% change in interest rate would have no material impact on earnings.

(b) Capital management

The Company's capital is defined to be shareholders' equity, bank credit facilities and working capital. The Company's objective in managing capital is to ensure it has adequate capital to finance operations and access to sources of capital sufficient to finance capital expenditures or capital acquisitions as opportunities present themselves. The Company manages its capital structure and makes changes to it in light of changes in economic conditions, anticipated or planned capital expenditures, opportunities for acquisitions and the risk characteristics of the underlying investments.

The Company monitors net debt determined as follows:

As at December 31	2011	2010
Cash	-	390,473
Trade, subscriptions and other receivables	1,469,272	1,571,177
Deposits and prepaid expenses	45,285	26,907
Accounts payable and accrued liabilities	(3,336,841)	(1,784,756)
Bank debt	(125,000)	-
(Net debt) working capital	(1,947,284)	203,801

The Company is not subject to any externally imposed capital requirements.

(c) Fair Value

As of December 31, 2011, 2010 and January 1, 2010 the carrying value of cash and cash equivalents, accounts receivables, bank debt and accounts payable and accrued liabilities included in the statement of financial position approximate fair value due to the short term nature of those instruments. Fair value is measured in accordance with the following:

Level 1 fair value measurements are based on unadjusted quoted market prices.

Level 2 fair value measurements are based on valuation models and techniques where the significant inputs are derived from quoted indices.

Level 3 fair value measurements are based on unobservable information.

Cash and cash equivalents are measured using level 1 inputs.

17. Transition from Canadian GAAP (C-GAAP) to IFRS

The effect of the Company's transition to IFRS, described in Note 2, is summarized in this note. In accordance with IFRS 1, "First-time adoption of IFRS", certain disclosures relating to the transition are also provided in this note.

IFRS 1 allows first time adopters of IFRS to elect a number of optional exemptions from the general principle of retrospective application of IFRS. The Company has taken the following optional exemptions:

Oil and Gas Exemption

IFRS 1 "Additional exemptions for First-time Adopters" provides an exemption for first-time adopters that accounted under their previous GAAP for exploration and development costs for oil and gas properties in the development or production phases in cost centres that include all properties in a large geographical area (defined as full cost method under Canadian GAAP). Under the exemptions, a first-time adopter may elect to measure oil and gas assets at the date of transaction to IFRS on a deemed cost basis, but does not permit continued application of the previous GAAP accounting policy. The Company followed a full cost approach under Canadian GAAP and has elected to measure oil and gas exploration and production assets at the date of transition to IFRS on a deemed cost basis. Oil and natural gas assets that were part of the full cost pool and determined to be developed or production assets under Canadian GAAP were allocated to CGUs pro rata using reserve values, subject to an impairment test, on the transition date of January 1, 2010.

Decommissioning liabilities

An entity that uses the deemed cost oil and gas exemption under IFRS 1 may also use an additional exemption with respect to decommissioning liabilities on oil and gas properties encompassed by the full cost method under Canadian GAAP. As the Company has elected to apply the deemed cost oil and gas exemption, the Company has also elected to apply this exemption and as such, the Company has re-measured the decommissioning liability as at January 1, 2010 under IAS 37 provisions, and has recognized directly into deficit any differences between that amount and the carrying amount of the liabilities at January 1, 2010 under Canadian GAAP.

The following is a reconciliation of the Company's total equity as reported under C-GAAP to IFRS at the transition date of January 1, 2010:

	Note	Share Capital	Warrants	Contributed Surplus	Deficit	Total Equity
Balance - C-GAAP		3,641,207	30,000	207,745	(2,100,084)	1,778,868
Decommissioning provision	(b)	-	-	-	(145,447)	(145,447)
Flow through shares	(g)	(139,000)	-	-	-	(139,000)
Balance – IFRS		3,502,207	30,000	207,745	(2,245,531)	1,494,421

17. Transition from Canadian GAAP to IFRS (continued):

The following is a reconciliation of the Company's total equity as reported under C-GAAP to IFRS at December 31, 2010:

	Note	Share Capital	Warrants	Contributed Surplus	Deficit	Total Equity
Balance - C-GAAP		7,332,127	54,000	615,845	(3,026,841)	4,975,131
Decommissioning provision	(b)	-	-	-	(208,969)	(208,969)
Flow through shares	(g)	2,000	-	-	-	2,000
Deferred taxes	(g)	-	-	-	(63,000)	(63,000)
Transaction costs	(e)	-	-	-	(164,881)	(164,881)
Depletion expense	(d)	-	-	-	368,485	368,485
Loss on disposition	(f)	-	-	-	(39,604)	(39,604)
Balance - IFRS		7,334,127	54,000	615,845	(3,134,810)	4,869,162

The following is a reconciliation of the Company's comprehensive loss as reported under C-GAAP to IFRS for the year ended December 31, 2010:

	Note	Comprehensive loss
Comprehensive loss - C-GAAP		(926,758)
Transaction costs expensed	(e)	(164,881)
Depletion expense	(d)	368,489
Accretion on decommissioning provision	(b)	(63,525)
Loss on disposition of property and equipment	(f)	(39,604)
Deferred taxes	(g)	(63,000)
Comprehensive loss - IFRS		(889,279)

Notes to reconciliations

(a) IFRS 1 election for full cost oil and gas entities

The Company elected an IFRS 1 exemption whereby the Canadian GAAP full cost pool was measured upon transition to IFRS as follows:

(i) The entire full cost pool was allocated to the producing/development assets and components pro rata using reserve values; and

(ii) The Company had no exploration and evaluation assets at the transition date under Canadian GAAP and thus no part of the Property and Equipment at that date were reclassified from the full cost pool to exploration and evaluation assets.

In 2010 certain capital expenditures for undeveloped land were classified as exploration and evaluation assets under IFRS amounting to $245,774 which under Canadian GAAP were recorded as property and equipment. Under neither accounting policy were these assets depleted.

17. Transition from Canadian GAAP to IFRS (continued):

(b) Decommissioning provision:

Under Canadian GAAP asset retirement obligations were discounted at a credit adjusted risk fee rate of 8 percent. Under IFRS the estimated cash flow to abandon and remediate the wells and facilities has been discounted at a risk free rate of 4% percent at the date of transition. Upon transition to IFRS this resulted in a $145,447 increase in the decommissioning obligations with a corresponding increase in the deficit. Also under IFRS the obligation is discounted at the end of each reporting period at the current risk free discount rate.

As a result of these two changes, the decommissioning obligation accretion expense on the decommissioning obligation increased by $63,525 during the year ended December 31, 2010 under IFRS compared to Canadian GAAP. In addition, under Canadian GAAP accretion of the obligation was included in depletion and accretion. Under IFRS it is included in finance expenses and for the Company, is the sole component to finance expense in 2010. Under Canadian GAAP expenditures on remediation and abandonment are not included in changes in non-cash working capital as is the case under IFRS. The Company did not incur any remediation or abandonment expenditures in 2010.

(c) Share-based payments:

Under Canadian GAAP, the Company recognized an expense related to share-based payments on a straight-line basis through the date of full vesting and did not incorporate a forfeiture multiple. Under IFRS, the Company is required to recognize the expense over the individual vesting periods for the graded vesting awards and estimate a forfeiture rate. Because all of the Company's options vested immediately upon granting, this change in accounting policy had no impact on the statement of financial position at the transition date or on the 2010 financial statements.

(d) Depletion policy:

Upon transition to IFRS, the Company adopted a policy of depleting oil and natural gas interests on a unit of production basis over proved plus probable reserves. The depletion policy under Canadian GAAP was based on units of production over proved reserves. In addition depletion was done on the Canadian cost centre under Canadian GAAP. IFRS requires depletion and depreciation to be calculated based on individual areas (fields or combinations thereof). The Company has chosen two areas (which are also the cash generating units) being Alberta heavy oil assets and Saskatchewan heavy oil assets. Equipment is also depleted on the same basis as oil and natural gas interests as the useful life of the equipment is dependent on the life of the related reserves.

There was no impact of this difference on adoption of IFRS at January 1, 2010 as a result of the IFRS 1 election as discussed above.

For the year ended December 31, 2010 computing depletion on the larger proved plus probable reserves resulted in a decrease to depletion expense of $368,485 with a corresponding change to property and equipment.

17. Transition from Canadian GAAP to IFRS (continued):

(e) Transaction costs incurred for business combinations:

Under Canadian GAAP transaction costs were capitalized as a component of the cost of the acquisition. Under IFRS transaction costs are expensed. This resulted in transaction expenses of $164,881 being expensed in the year ended December 31, 2010 under IFRS which were capitalized and depleted under Canadian GAAP. There were corresponding changes to depletion expense and property and equipment.

(f) Disposition of property and equipment

Under Canadian GAAP the proceeds on the disposition of oil and natural gas assets and equipment were recorded as a reduction of the full cost pool unless the impact on depletion expense was greater than 20%. If the latter was the case than a gain or loss was recorded. The Company disposed of certain oil and natural gas interests in 2010 for which no gain or loss was recorded under Canadian GAAP. Under IFRS a loss of $39,604 was recorded with corresponding changes to depletion expense and property and equipment.

(g) Flow through shares

Under Canadian GAAP the entire proceeds from issuing flow through shares was recorded as equity at the time of receipt. This form of equity allows the investor to claim income tax deductions for the flow through of certain resource deductions renounced to the investor by the Company. Under Canadian GAAP the cost of the forgone income tax deductions is recorded as a reduction of equity by the Company at the time it files the renouncement with the income tax authorities and the impact on deferred tax assets or liabilities is also recorded at that time as income tax recovery in earnings. Under IFRS, at the time of the issue, the proceeds are classified in part as equity based on the fair value of the share price at the date of issue of the flow through shares and in part as a liability based on the excess of the issue price over the fair value of the share price, if any, at the issue date. The resulting liability is reduced at the time the renouncement is filed with the income tax authorities and the impact on deferred tax assets or liabilities is also recorded at that time as an income tax recovery on the statement of income. At the transition date to IFRS the Company was impacted by this change with a $139,000 increase in accounts payable and accrued liabilities and a corresponding decrease to share capital in equity. The filing of renouncements in 2010 and 2011 on the flow through shares with outstanding commitments at the transition date resulted in an income tax recovery of $78,000 and $61,000 respectively and the corresponding impact on the loss for the year.

(h) Statement of cash flows

The transition from Canadian GAAP to IFRS had no significant impact on cash flows generated by the Company. Under IFRS cash flows relating to interest are classified as operating, investing or financing depending on the nature of the interest incurred. The Company has classified its cash outflows of interest as financing activity under IFRS. Under Canadian GAAP, cash outflows of interest were classified as operating activity.