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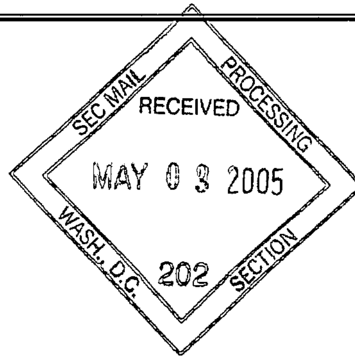

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MANAGEMENT'S DISCUSSION AND ANALYSIS

For the fiscal year ended December 31, 2004

MANAGEMENT'S DISCUSSION AND ANALYSIS

Overview

This management's discussion and analysis ("**MD&A**") is intended to assist in the understanding of the trends and significant changes in the financial condition and results of operations of Highpine Oil & Gas Limited ("**Highpine**" or the "**Company**") for the years presented. This MD&A has been prepared by management and should be read in conjunction with the audited consolidated financial statements and notes thereto for the years ended December 31, 2004 and 2003. All comparisons refer to the year ended 2004 with the year ended 2003, unless otherwise indicated. In accordance with regulatory guidelines, the Company has not presented comparative figures for prior quarterly periods as the Company became a public entity on April 5, 2005 and comparative figures were not available for prior quarterly periods.

On April 5, 2005, Highpine completed its initial public offering of 4,000,000 common shares at a price of $18.00 per share for gross proceeds of $72.0 million. Upon completion of the initial public offering, the common shares of Highpine were listed and posted for trading on the Toronto Stock Exchange under the symbol "HPX". In April 2005, the Company announced that it had entered into a merger agreement with Vaquero Energy Ltd. ("**Vaquero**") whereby the Company will acquire all of the issued and outstanding shares of Vaquero pursuant to a plan of arrangement to be approved by the Vaquero shareholders no later than June 30, 2005.

This MD&A uses the terms "cash flow from operations" and "cash flow" which are not recognized measures under Canadian generally accepted accounting principles ("**GAAP**"). Management believes that in addition to net earnings, cash flow is a useful supplemental measure as it provides an indication of the results generated by Highpine's principal business activities before the consideration of how these activities are financed or how the results are taxed. Investors are cautioned, however, that this measure should not be construed as an alternative to net earnings determined in accordance with GAAP, as an indication of Highpine's performance. Highpine's method of calculating cash flow may differ from other companies, and accordingly, it may not be comparable to measures used by other companies. Highpine calculates cash flow from operations as "funds from operations" before the change in non-cash working capital related to operating activities.

Where amounts are expressed on a barrel of oil equivalent (boe) basis, natural gas volumes have been converted to a barrel of oil equivalent (boe) at a ratio of 6,000 cubic feet of natural gas to one barrel of oil equivalent. This conversion ratio is based upon an energy equivalent conversion method primarily applicable at the burner tip and does not represent value equivalence at the wellhead. Boe figures may be misleading, particularly if used in isolation.

All references to dollar values refer to Canadian dollars unless otherwise stated.

Financial Results

In March 2004, Highpine indirectly acquired assets from Rubicon Energy Corporation (the "**Rubicon Acquisition**"), for approximately $51 million. At the time of the Rubicon Acquisition, Rubicon owned significant producing properties in the Pembina area. The results of operations from the Rubicon Acquisition are included in Highpine's operations from March 3, 2004.

Revenue and Production

Gross oil and gas revenue for 2004 totalled $41.0 million representing a 142% increase over 2003 gross revenue of $16.9 million. The increase in revenue was primarily as a result of increased production volumes resulting from the Rubicon Acquisition combined with production increases in the Pembina and Retlaw areas and increased prices for oil and NGL's. Oil and NGL revenue was impacted by a hedging loss of $2.7 million in 2004. Hedging gains on natural gas in 2003 were $533,000 offset by hedging losses on oil and NGL's of $50,000, for a net hedging gain of $483,000. As at December 31, 2004, the 700 bbls/d oil hedge for 2005 had an unrealized loss of approximately $1.0 million.

Production volumes for 2004 averaged 2,648 boe/d compared to an average rate of 1,157 boe/d in 2003, an increase of 1,492 boe/d or 129%.

The following table sets out production volumes for the years indicated.

	2004	2003	% Change
Production			
Oil and NGLs (bbls/d)	1,578	443	256%
Natural gas (mcf/d)	6,423	4,281	50%
Boe/d	2,648	1,157	129%

Oil and NGL prices in 2004 were $42.91 bbl as compared to $34.29 bbl in 2003, an increase of 25%. Natural gas prices in 2004 averaged $6.91mcf as compared to $7.28 mcf in 2003, a decrease of 5%.

The contribution of oil to revenue increased to 60% in 2004 from 33% in 2003, reflecting a weighting of new production to oil, particularly in the Pembina area.

The following table sets out the change in components of revenue for the years indicated.

	($000's)		
	2004	2003	% Change
Revenue			
Oil and NGLs	$ 24,780	$ 5,546	347%
Natural gas	16,244	11,380	43%
	$ 41,024	$ 16,926	142%
Revenue Contribution			
Oil and NGLs	60%	33%	
Natural gas	40%	67%	

In 2004, the Company also received $1.0 million of processing and pipeline fees relating to fees received for facility third party volumes, up from $0.5 million in 2003 as a result of a gas gathering line that had commenced operations in 2004. In 2005, additional processing revenue is expected to be generated with the completion of a new gas plant at Joffre.

Royalties

Royalties, after giving effect to hedges, averaged 25% of revenue for 2004 compared to 18% for 2003. Royalty rates, excluding the hedging loss, averaged 23% of revenue in 2004, and excluding the hedging gain in 2003 averaged 19%. Royalty rates as a percentage of revenue were higher in 2004 due to higher royalty rates on properties acquired pursuant to the Rubicon Acquisition and higher royalty rates on wells at Pembina.

Production Expenses

Production expenses including transportation costs totalled $7.0 million for 2004 compared to $2.8 million for 2003. Production expenses increased 7% to $7.18 boe for 2004 from $6.69 boe for 2003. These increases were as a result of higher operating costs relating to the properties acquired pursuant to the Rubicon Acquisition and increased industry related costs.

Operating Netbacks

Operating netbacks decreased 6% from $27.30 boe for 2003 to $25.74 boe for 2004, primarily as a result of increased royalties and operating costs per boe.

The following table summarizes operating netbacks for the years indicated.

	2004	2003
Oil and NGLs price/bbl	$ 42.91	$ 34.60
Natural gas price/mcf	6.91	7.28
Sales price/boe	42.32	40.10
Net royalties/boe	(10.46)	(7.36)
Production expenses/boe (net of fees)	(6.12)	(5.44)
Operating netbacks/boe	$ 25.74	$ 27.30

General and Administrative Expenses

General and administrative expenses decreased 34% from $4.40 boe in 2003 to $2.90 boe in 2004 as volume increases in 2004 resulted in lower per unit costs.

The following table summarizes general and administrative expenses for the years indicated.

	($000's)		
	2004	2003	% Change
Gross expenses	$ 3,110	$ 2,032	53%
Capitalization	(295)	(176)	68%
Net expenses	$ 2,815	$ 1,856	52%
$/boe	2.90	4.40	(34%)
% capitalized	9%	9%	

Stock-based Compensation

Stock based compensation expense of $0.4 million was recorded in 2004 compared to $0.1 million for 2003. The increase in the expense was primarily the result of an increase in the number of stock options granted in 2004.

Financing Costs

Interest and finance costs for 2004 increased to $2.3 million, up from $0.2 million in 2003 due to higher average debt levels in 2004 that arose from the Rubicon Acquisition combined with capital spending during the year. The effective average interest rate on borrowings in 2004 was approximately 4.4%. During 2003 bank debt was eliminated in September with the proceeds received from the sale of shares of Monolith Oil Corp. ("**Monolith**").

Depletion, Depreciation and Accretion

Depletion, depreciation and accretion ("**DD&A**") amounted to $14.9 million or $15.36 boe for 2004, compared with $4.9 million or $11.55 boe in 2003, representing a 33% increase on a per boe basis. The increase in DD&A was due to costs included in the depletion base in respect of the Rubicon Acquisition as well as significant land, seismic and facility expenditures made in 2004.

Other Income

During 2003, Highpine sold its shares in Monolith, a private oil and gas company, for a gain totalling approximately $17.4 million. Consideration received on the disposition of the investment consisted of $14.2 million of cash and cash equivalents and a secured debenture in the principal amount of $3.7 million bearing interest at 9% per annum, payable monthly. The debenture was repaid in January 2004. As a result of the resolution of certain contingent items on the disposition of the shares in Monolith, the net proceeds were adjusted during 2004 resulting in an increase in the gain on sale by $0.3 million.

Income Taxes

Highpine has not incurred any cash taxes, other than Large Corporation Tax, which amounted to $185,000 in 2004 compared to $70,000 for 2003. Large Corporation Tax was higher in 2004 due to higher debt levels incurred on the Rubicon Acquisition as well as from the equity offerings made in the year. Although current tax horizons depend on product prices, production levels and the nature, magnitude and timing of capital expenditures, Highpine management currently believes no cash income tax will be payable for two to three years. The effective income tax rate for 2003 was lowered significantly from the rate for 2004 by the exclusion of half of the capital gain on the sale of the Monolith shares and the receipt of a non-taxable dividend from Monolith, described in Other Income above.

In July 2004, the Company issued $4.8 million of flow-through common shares. All qualifying expenditures relating to the flow-through common shares were incurred in 2004. The tax impact of the flow-through common shares will be booked in the first quarter of 2005 when the expenditures were renounced to the investors.

Cash Flow and Net Earnings

Cash flow from operations increased 70% to $19.8 million in 2004 compared to $11.6 million in 2003 ($1.22 and $0.80 respectively per diluted share) reflecting increased production volumes and commodity prices received. Net earnings declined in 2004 versus 2003 ($0.20 and $1.31 respectively per diluted share) primarily as a result of the one time gain on the sale of shares of Monolith included in 2003 net earnings. Cash flow from operations is determined by adding non-cash expenses to income or loss for the year and does not include the change in working capital applicable to operating activities.

Liquidity and Capital Resources

At December 31, 2004, Highpine had a working capital deficiency of $49.6 million with capital expenditures being funded by funds from operations, the $10.8 million of gross proceeds realized from the private placement of 2,000,000 common shares in July 2004, the $29.7 million gross proceeds realized from the private placement of 3,300,000 special warrants in October 2004 and the Corporation's bank line which was drawn to $35 million. In February 2005, Highpine's credit facilities were increased to $80 million with $25 million being non-revolving and due for repayment no later than May 31, 2005. On April 5, 2005 Highpine completed its initial public offering of 4,000,000 common shares for gross proceeds of $72.0 million which was primarily used to pay down bank debt. At April 22, 2005, approximately $4.0 million was outstanding under the banking facilities.

Highpine's capital budget for 2005 is approximately $60 million and includes the drilling of approximately 40 gross wells (20 net). Of the total budget, approximately $15 million is allocated to development drilling, approximately $27 million is allocated to exploration drilling (including undeveloped land acquisition and seismic programs) and approximately $18 million is allocated to facilities and tie-ins.

Capital Expenditures

Gross capital expenditures were $66.1 million in 2004, excluding the Rubicon Acquisition, up 170% from gross capital expenditures of $24.6 million in 2003. The increase relates primarily to Highpine's drilling programs at Pembina and Joffre.

The following table sets out Highpine's net capital expenditures for the years indicated.

	($000's)		
	2004	2003	% Change
Land and seismic	$ 17,465	$ 11,644	50%
Drilling and completions	26,897	8,793	206%
Facilities and equipment	21,633	2,843	661%
Property acquisitions and disposition (net)	(4,973)	194	-
Corporate acquisition	51,151	-	-
Other	111	32	247%
Total	$ $112,284	$ $23,506	378%

Exploration and development expenses more than tripled from $8.8 million in 2003 to $26.9 million in 2004 with expenditures for land and seismic increasing 50% to $17.5 million in 2004.

Rubicon Acquisition

In March 2004, Highpine completed the Rubicon Acquisition. The acquisition was accounted for by the purchase method of accounting with the results of operations included from the date of acquisition. The allocation of the purchase price to the fair value of assets and liabilities acquired was as follows:

Net assets acquired and liabilities assumed:		($000's)
Property, plant and equipment	$	51,151
Goodwill		14,081
Working capital deficiency		(6,314)
Asset retirement obligations		(950)
Future income taxes		(12,485)
Bank indebtedness		(3,394)
	$	42,089
Consideration was comprised of		
Cash	$	41,810
Transaction costs		279
	$	42,089

Contracted Obligations and Commitments

The Company has contractual obligations in the normal course of operations, including the purchase of assets and services, operating agreements, sales commitments, royalty obligations and lease rental obligations. These obligations are of a recurring and consistent nature and impact cash flow in an ongoing manner. The Company also has commitments that are disclosed in note 12 of the audited consolidated financial statements. The Company has a $45.0 million revolving term credit facility and a $10.0 million demand operating facility which is expected to be renewed by May 31, 2005.

Related Party Transactions

The Company has a loan due from an officer of the Company totalling $100,000 plus accrued interest of $17,000 at December 31, 2004. The loan bears interest at 4.75% per annum, is secured by 57,143 common shares and is due on demand.

The Chairman, President and Chief Executive Officer of the Company, was also a director and shareholder of a company which together with the Company jointly acquired all of the outstanding shares of Rubicon Energy Corporation on March 3, 2004. The Chairman, President and Chief Executive Officer of the Company is also a director and shareholder of a private oil and gas company in which the Company has an investment of $1.0 million, comprised of 960,000 common shares.

Changes in Accounting Policies

Asset Retirement Obligations

A new Canadian accounting standard for asset retirement obligations is effective for fiscal years beginning on or after January 1, 2004. As a result of the implementation of this new standard, the present value of the liability for future abandonment costs has been recorded at $2.0 million at December 31, 2004. The transitional provisions associated with this new standard require that it be applied retroactively which gives rise to a restatement of certain prior periods. As a result, comparative numbers for the year ended December 31, 2003 have been restated. Property plant and equipment increased by $0.3 million, future income taxes increased by $70,000 and retained earnings increased by $0.1 million.

Stock-Based Compensation

Highpine retroactively adopted the amended standard with respect to stock based compensation, effective during 2004. As a result of its adoption of the amended standard, Highpine recognized a compensation expense of $0.1 million for the year ended December 31, 2003 and $12,337 for the year ended December 31, 2002, with a decrease in net earnings and a corresponding increase in contributed surplus.

Hedging

Effective for 2004, the new CICA Accounting Guideline 13, "Hedging Relationships" requires that hedging relationships be identified, designated, documented and measured in order for Highpine to apply hedge accounting. Highpine was in compliance with this new standard in 2004, and all eligible hedging instruments will continue to be accounted for using hedge accounting.

Transportation

Effective January 1, 2004, Highpine commenced classifying field level transportation costs as a production expense rather than as a deduction from oil and gas revenues. The comparative figures have been disclosed in a similar manner. Adopting this presentation has no impact on cash flow from operations or net earnings.

Financial Instruments

Highpine makes use of specific commodity hedging instruments to reduce the variability in cash flows from fluctuations in product prices, to help ensure a source of funding for the capital programs.

At December 31, 2004, Highpine had in place a commodity swap agreement under which it agreed to sell 700 bbl/d at $47.20 bbl for the 2005 calendar year. The contract settles monthly and has qualified for hedge accounting whereby any gains or losses are included in oil revenue in the month realized.

Critical Accounting Estimates

Highpine follows the full cost method of accounting for exploration and development expenditures wherein all costs related to the exploration for and the development of oil and gas reserves are capitalized whether successful or not. Depletion of exploration and development costs and depreciation of production equipment are provided on the unit-of-production method based upon estimated proven oil and gas reserves before royalties in each area of interest. For purposes of this calculation, reserves and production of natural gas are converted to common units based on their approximate relative energy content. The cost of acquiring and evaluating unproven properties are initially excluded from the depletion calculation. These properties are assessed periodically for impairment. When proved reserves are assigned or the property is considered to be impaired, the cost of the property or the amount of the impairment is added to the costs subject to depletion. Changes in estimated proven reserves or further development costs have a direct impact on depletion and depreciation expense.

The alternate method of accounting for oil and natural gas properties and equipment is the successful efforts method. A major difference in applying the successful efforts method is that exploratory dry holes and geological and geophysical exploration costs would be charged against net earnings in the year incurred rather than being capitalized to property, plant and equipment.

Oil and natural gas reserves

All of Highpine's proved oil and gas reserves are evaluated and reported on by an independent petroleum engineering consultant. The estimation of reserves is a subjective process. Forecasts are based on engineering data, projected future rates of production, estimated commodity price forecasts and the timing of future expenditures, all of which are subject to a number of uncertainties and various interpretations. Highpine expects that over time its reserve estimates will be revised upward or downward based on updated information such as results of future drilling, testing and production levels. Reserve estimates can have a significant impact on net earnings, as they are a key component in the calculation of depletion and depreciation. A revision to the reserve estimates could result in a higher or lower DD&A charge to net earnings. Downward revisions to reserve estimates could also result in a write-down of oil and natural gas properties, plant and equipment under the ceiling test.

Full Cost Accounting Ceiling Test

Highpine places a limit on the carrying value of property, plant and equipment, which may be depleted against revenues of future periods (the "**ceiling test**"). The carrying value is assessed to be recoverable when the sum of the undiscounted cash flows expected from the production of proved reserves, the lower of cost and market of unproved properties and the cost of major development projects exceeds the carrying value. When the carrying value is not assessed to be recoverable, an impairment loss is recognized to the extent that the carrying value of assets exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves, the lower of cost and market expected from the production of proved and probable reserves, the lower of cost and market of unproved properties and the cost of major development projects. The cash flows are estimated using expected future product prices and costs and are discounted using a risk-free interest rate. No write-down was required at December 31, 2004.

Asset Retirement Obligations

Highpine recognizes the fair value of an Asset Retirement Obligation ("**ARO**") in the period in which it is incurred when a reasonable estimate of the fair value can be made. The fair value of the estimated ARO is recorded as a liability, with a corresponding increase in the carrying amount of the related asset. The capitalized amount is depleted on the unit-of-production method based on proved reserves. The liability amount is increased each reporting period due to the passage of time and the amount of accretion is expensed to income in the period. Actual costs incurred upon the settlement of the ARO are charged against the ARO.

Determinations of the original undiscounted costs are based on estimates using current costs and technology in accordance with existing legislation and industry practice. The estimation of these costs can be affected by factors such as the number of wells drilled, well depth and area specific environmental legislation.

Goodwill

Goodwill is the residual amount that results when the purchase price of an acquired business exceeds the sum of the amounts allocated to the assets acquired, less liabilities assumed, based on their fair values. Goodwill is not amortized and is tested for impairment annually or more frequently if events or changes in circumstances indicate that the asset might be impaired. The impairment test is carried out in two steps. In the first step, the carrying amount of the reporting segment is compared to its fair value. When the fair value of a reporting segment exceeds its carrying amount, goodwill of the reporting segment is considered not be impaired and the second step of the impairment test is unnecessary. The second step is carried out when the carrying amount of the reporting segment's goodwill exceeds its fair value, in which case the implied fair value of the reporting segment's goodwill is compared with its carrying amount to measure the amount of the impairment loss, if any. The implied fair value of goodwill is determined in the same manner as the value of the goodwill is determined in a business combination using the fair value of the reporting segment as if it were the purchase price. When the carrying amount of the reporting segment's goodwill exceeds the implied fair value of the goodwill, an impairment loss is recognized in an amount equal to the excess.

Future Income Taxes

Highpine's income taxes are calculated using the liability method of accounting for income taxes. Under this method, future income tax liabilities and future income tax assets are recorded based on the differences between the carrying amount of assets and liabilities in the consolidated balance sheet and their tax basis using income tax rates substantively enacted at the balance sheet date. The effect of changes in rates on future income tax liabilities and assets is recognized in the period in which the change occurs. A valuation allowance is recorded against any future income tax assets if it is more likely than not that the asset will not be realized.

The liability method of accounting requires Highpine to schedule out all existing temporary differences and to recalculate the future income tax balance using tax rates in effect when temporary differences are expected to reverse. Forecasts of estimated net revenue streams are utilized to calculate the future tax provision and, as such, are subject to revisions, both upwards and downwards, that are not known at this time. In addition to these revisions, future capital activities can impact the timing of the reversal of any temporary differences. These differences can have an impact on the amount of future taxes determined at a point in time, and to the extent that these differences are created, they can impact the charge against earnings for future taxes.

Stock-based Compensation

Highpine's share option plan provides for granting of options to officers, directors, employees and consultants. Highpine uses the fair value method for valuing stock option grants. Compensation costs attributable to share options granted are measured at estimated fair value at the grant date and expensed over the term of the option with a corresponding increase to contributed surplus. Upon exercise of the stock options, consideration paid by the option holder, together with the amount previously recognized in contributed surplus is recorded as an increase to share capital.

Business Risks and Uncertainties

Highpine is exposed to numerous risks and uncertainties associated with the exploration for and development and acquisition of crude oil, natural gas and NGLs. Primary risks include the uncertainty associated with exploration drilling, changes in production practices, product pricing, industry competition and government regulation.

Drilling activities are subject to numerous technical risks and uncertainties. Highpine attempts to minimize exploration risk by utilizing trained professional staff and conducting extensive geological and geophysical analysis prior to drilling wells.

Highpine utilizes sound marketing practices in an attempt to partially offset the cyclical nature of commodity prices which is subject to external influences beyond Highpine's control. Fluctuations in commodity prices and foreign exchange rates may significantly impact Highpine's revenue. The oil and natural gas industry is extremely competitive and Highpine must compete with numerous larger, well-established organizations in all phases of the exploration business.

Highpine monitors and complies with current government regulations that affect its activities, although operations may be adversely affected by changes in government policy, regulations or taxation. In addition, Highpine maintains a level of liability, property and business interruption insurance which is believed to be adequate for Highpine's size and activities, but is unable to obtain insurance to cover all risks within the business or in amounts to cover all possible claims.

Special Note Regarding Forward-Looking Statements

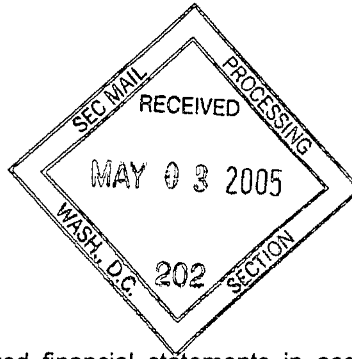
Certain statements in this MD&A are forward-looking statements subject to substantial known and unknown risks and uncertainties, most of which are beyond Highpine's control. These risks may cause actual financial and operating results, performance, levels of activity and achievements to differ materially from those expressed in, or implied by, such forward-looking statements.

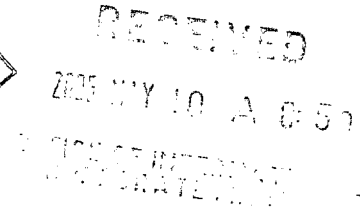
Such factors include, but are not limited to: the impact of general economic conditions in Canada and the United States; industry conditions including changes in laws and regulations, including adoption of new environmental laws and regulations and changes in how they are interpreted and enforced; competition; the lack of availability of qualified personnel or management; fluctuations in commodity prices; the results of exploration and development drilling and related activities; imprecision in reserve estimates; the production and growth potential of the Company's various assets; fluctuations in foreign exchange or interest rates; stock market volatility; risks associated with hedging activities; and obtaining required approvals from regulatory authorities.

Accordingly, there is no assurance that the expectations conveyed by the forward-looking statements will prove to be correct. All subsequent forward-looking statements, whether written or orally attributable to the Company or persons acting on hits behalf, are expressly qualified in their entirety by these cautionary statements. The Company undertakes no obligation to publicly update or revise any forward-looking statements except as required by applicable securities laws.

April 22, 2005

File No. 82-34869





MANAGEMENT'S REPORT

Management has prepared the consolidated financial statements in accordance with accounting principles generally accepted in Canada. If alternative accounting methods exist, management has chosen those it deems most appropriate in the circumstances. Financial statements are not precise since they include certain amounts based on estimates and judgments. Management has ensured that the consolidated financial statements are presented fairly in all material respects. Management has also prepared the financial information presented in Management's Discussion and Analysis and ensured that it is consistent with information in the consolidated financial statements.

Highpine Oil & Gas Limited maintains internal accounting and administrative controls designed to provide reasonable assurance that the financial information is relevant, reliable and accurate and that assets are appropriately accounted for and adequately safeguarded.

The Board of Directors is responsible for reviewing and approving the consolidated financial statements and Management's Discussion and Analysis and, primarily through its Audit Committee, ensures that management fulfills its responsibilities for financial reporting.

The Audit Committee is appointed by the Board and is composed of non-management Directors. The Audit Committee has met with management and with the external auditors to discuss internal controls and reporting issues and to satisfy itself that management's responsibilities are properly discharged. It reviews the consolidated financial statements and the external auditors' report. The Audit committee also considers, for review by the Board and approval by shareholders, the engagement or reappointment of external auditors.

KPMG LLP, the external auditors, has audited the consolidated financial statements in accordance with the auditing standards generally accepted in Canada on behalf of the shareholders. KPMG LLP have full and free access to the Audit Committee

(signed) *"A. Gordon Stollery"*
A. Gordon Stollery
President and Chief Executive Officer

(signed) *"Harry D. Cupric"*
Harry D. Cupric
Vice President, Finance and
Chief Financial Officer

Calgary, Canada
April 22, 2005

AUDITORS' REPORT TO THE SHAREHOLDERS

We have audited the consolidated balance sheets of Highpine Oil & Gas Limited as at December 31, 2004 and 2003 and the consolidated statements of earnings and retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. 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 plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2004 and 2003 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

(signed) *"KPMG LLP"*
Chartered Accountants

Calgary, Canada
April 22, 2005

HIGHPINE OIL & GAS LIMITED

Consolidated Balance Sheets

December 31, 2004 and 2003

	2004	2003
		(Restated-note 2)
Assets		
Current assets:		
Cash and cash equivalents	$ -	$ 537,682
Accounts receivable (note 3)	13,366,408	3,128,001
Debenture receivable (note 5)	-	3,736,697
Prepaid expenses and deposits	658,978	157,835
	14,025,386	7,560,215
Property, plant and equipment (note 4)	134,282,197	36,239,633
Long-term investments, at cost (note 5)	1,000,000	240,000
Goodwill (note 13)	14,081,000	-
	$163,388,583	$ 44,039,848
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$ 28,840,343	$ 2,302,697
Bank indebtedness (note 8)	34,821,996	-
	63,662,339	2,302,697
Future income taxes (note 6)	20,419,084	6,973,688
Asset retirement obligations (note 9)	1,973,735	377,894
Shareholders' equity:		
Share capital (note 7)	52,829,758	13,455,090
Contributed surplus (note 7)	511,258	114,787
Retained earnings	23,992,409	20,815,692
	77,333,425	34,385,569
Commitments (notes 11 and 12)		
Subsequent events (notes 7 and 14)		
Contingency (note 15)		
	$163,388,583	$ 44,039,848

See accompanying notes to consolidated financial statements.

On behalf of the Board:

(signed) *"Richard G. Carl"* Director

(signed) *"Andrew Krusen"* Director

HIGHPINE OIL & GAS LIMITED

Consolidated Statements of Earnings and Retained Earnings

Years ended December 31, 2004 and 2003

	2004	2003
		(Restated-note 2)
Revenues:		
Oil and gas revenues	$ 41,024,339	$ 16,926,338
Royalties, net of Alberta Royalty Tax Credits	(10,139,791)	(3,108,708)
	30,884,548	13,817,630
Processing and pipeline fees	1,026,236	533,000
	31,910,784	14,350,630
Expenses:		
Operating costs	6,960,424	2,826,287
General and administrative	2,814,796	1,856,417
Depletion, depreciation and accretion	14,887,350	4,876,061
Interest and finance costs	2,296,061	195,152
Stock based compensation (note 7)	396,471	102,450
	27,355,102	9,856,367
Earnings before the undernoted	4,555,682	4,494,263
Other items:		
Interest and dividend income (note 5)	56,191	2,213,688
Gain on sale of investment (note 5)	349,844	17,438,860
	406,035	19,652,548
Earnings before taxes	4,961,717	24,146,811
Taxes (note 6):		
Current	185,000	70,394
Future	1,600,000	4,968,669
	1,785,000	5,039,063
Net earnings	3,176,717	19,107,748
Retained earnings, beginning of year (note 2)	20,815,692	1,707,944
Retained earnings, end of year	$ 23,992,409	$ 20,815,692
Net earnings per share (note 7)		
Basic	$0.20	$1.32
Diluted	$0.20	$1.31

See accompanying notes to consolidated financial statements.

HIGHPINE OIL & GAS LIMITED

Consolidated Statements of Cash Flows

Years ended December 31, 2004 and 2003

	2004	2003
		(Restated-note 2)
Cash provided by (used in):		
Operations:		
Net earnings	$ 3,176,717	$ 19,107,748
Items not involving cash:		
Depletion, depreciation and accretion	14,887,350	4,876,061
Gain on sale of investment	(349,844)	(17,438,860)
Future income taxes	1,600,000	4,968,669
Shares issued for services performed	62,500	-
Stock based compensation	396,471	102,450
Funds from operations	19,773,194	11,616,068
Change in non-cash working capital relating to operations (note 10)	(2,940,300)	(2,200,905)
	16,832,894	9,415,163
Financing:		
Common shares issued for cash, net of share issue costs	10,692,000	81,346
Special warrants issued for cash, net of issue costs	27,980,564	-
Increase in bank indebtedness	31,427,996	-
	70,100,560	81,346
Investments:		
Property, plant and equipment additions	(66,106,372)	(24,652,018)
Debenture receivable repayment	3,736,697	-
Proceeds on sale/return of capital on investment	349,844	14,202,163
Long-term investment, at cost	(760,000)	(240,000)
Proceeds on the disposition of property, plant and equipment	4,973,299	1,146,920
Net cash paid on business combination (note 13)	(42,089,000)	-
Change in non-cash working capital relating to investing activities (note 10)	12,424,396	(1,005,837)
	(87,471,136)	(10,548,772)
Decrease in cash and cash equivalents	(537,682)	(1,052,263)
Cash and cash equivalents, beginning of year	537,682	1,589,945
Cash and cash equivalents, end of year	$ -	$ 537,682

See accompanying notes to consolidated financial statements.

Incorporation:

Highpine Oil & Gas Limited (the "Company") was incorporated under the laws of the Province of Alberta on April 2, 1998. The Company is involved in the exploration, development and production of petroleum and natural gas.

1. Significant accounting policies:

The consolidated financial statements of the Company have been prepared by management in accordance with Canadian generally accepted accounting principles. In the preparation of these financial statements, management has made estimates and assumptions that affect the recorded amounts of certain of the Company's assets, liabilities, revenues and expenses. The most significant estimates relate to the amounts recorded for the depletion and depreciation of property, plant and equipment and the determination of the asset retirement obligations as well as the cost recovery assessment for property, plant and equipment, goodwill and long-term investments. While it is the opinion of management that these consolidated financial statements have been properly prepared within reasonable limits of materiality and within the framework of the significant accounting policies summarized below, actual results could differ from the estimates made.

(a) Basis of presentation:

These consolidated financial statements include the accounts of the Company and its subsidiaries. The Company's investment in Rubicon Energy Corporation, representing a 50% ownership interest, is accounted for as a joint venture and accordingly, the financial statements reflect only the Company's proportionate interest in the assets, liabilities, revenues and expenses of Rubicon Energy Corporation.

Substantially all of the Company's exploration and development activities are conducted jointly with others. Accordingly, the financial statements reflect only the Company's proportionate interest in such activities.

Certain of the comparative figures have been reclassified to conform to the current period's presentation.

(b) Petroleum and natural gas properties:

The Company follows the full cost method of accounting for exploration and development expenditures wherein all costs related to the exploration for and the development of oil and gas reserves are capitalized. These costs include lease acquisition costs, geological and geophysical expenses, carrying charges of unproven properties, costs of drilling and completing wells and oil and gas production equipment. Proceeds received from the disposal of properties are normally credited against accumulated costs unless this would result in a significant change in the depletion rate of in excess of 20%, in which case a gain or loss is computed and reflected in the consolidated statement of earnings.

1. **Significant accounting policies (continued):**

   (b) Petroleum and natural gas properties (continued):

   Depletion of exploration and development costs and depreciation of production equipment are provided on the unit-of-production method based upon estimated proven oil and gas reserves before royalties in each cost centre as determined by independent engineers. For purposes of this calculation, reserves and production of natural gas are converted to common units based on their approximate relative energy content. The cost of acquiring and evaluating unproven properties are initially excluded from the depletion calculation. These properties are assessed periodically for impairment. When proved reserves are assigned or the property is considered to be impaired, the cost of the property or the amount of the impairment is added to the costs subject to depletion.

   The Company places a limit on the carrying value of property, plant and equipment and other assets, which may be depleted against revenues of future periods (the "ceiling rest"). The carrying value is assessed to be recoverable when the sum of the undiscounted cash flows expected from the production of proved reserves, the lower of cost and market of unproved properties and the cost of major development projects exceeds the carrying value. When the carrying value is not assessed to be recoverable, an impairment loss is recognized to the extent that the carrying value of assets exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves, the lower of cost and market of unproved properties and the cost of major development projects. The cash flows are estimated using expected future product prices and costs and are discounted using a risk-free interest rate.

   (c) Asset retirement obligations:

   The Company recognizes the fair value of an Asset Retirement Obligation ("ARO") in the period in which it is incurred when a reasonable estimate of the fair value can be made. The fair value of the estimated ARO is recorded as a liability, with a corresponding increase in the carrying amount of the related asset. The capitalized amount is depleted using the unit-of-production method based on proved reserves. The liability amount is increased each reporting period due to the passage of time and the amount of accretion is expensed to income in the period. Actual costs incurred upon the settlement of the ARO are charged against the ARO.

1. Significant accounting policies (continued):

(d) Office equipment and computers:

Office equipment and computers are stated at cost. Depreciation is provided for using the declining balance method at 20% per year.

(e) Goodwill:

Goodwill is the residual amount that results when the purchase price of an acquired business exceeds the sum of the amounts allocated to the assets acquired, less liabilities assumed, based on their fair values. Goodwill is not amortized and is tested for impairment annually or more frequently if events or changes in circumstances indicated that the asset might be impaired. The impairment test is carried out in two steps. In the first step, the carrying amount of the segment is compared to its fair value. When the fair value of the segment exceeds its carrying amount, goodwill is considered not to be impaired and the second step of the impairment test is unnecessary. The second step is carried out when the carrying amount of the Company's goodwill exceeds its fair value, in which case the implied fair value of the Company's goodwill is compared with its carrying amount to measure the amount of the impairment loss, if any. The implied fair value of goodwill is determined in the same manner as the value of the goodwill is determined in a business combination using the fair value of the Company as if it were the purchase price. When the carrying amount of the Company's goodwill exceeds the implied fair value of the goodwill, an impairment loss is recognized in an amount equal to the excess.

(f) Long-term investment:

The Company's long-term investment is accounted for by the cost method (see note 5). The net income of this company is reflected in the determination of the net earnings of the Company only to the extent of dividends received.

The carrying value of the Company's long-term investment is periodically reviewed by management to determine if the facts and circumstances suggest that the investment may be impaired. Any impairment identified through this assessment would result in a write-down of the investment and a corresponding charge to earnings.

(g) Revenue recognition:

Revenues associated with sales of crude oil, natural gas and natural gas liquids are recorded when title passes to the customer. Revenues from properties in which the Company has an interest with other producers are recognized on the basis of the Company's net working interest.

1. **Significant accounting policies (continued):**

(h) Financial instruments:

The Company may enter into derivative instrument contracts to manage its exposure related to oil and gas prices. The Company does not enter into derivative instrument contracts for trading or speculative purposes. The Company believes that all derivative instruments entered into are effective hedges, both at inception and over the term of the instrument, as the term and notional amount have not and are not expected to exceed the Company's firm commitment or forecasted production. These derivative instrument contracts are recognized in oil and gas revenues and cash flows in the period in which the revenues associated with the hedged transaction are recognized.

(i) Future income taxes:

Income taxes are calculated using the liability method of accounting for income taxes. Under this method, future income tax liabilities and future income tax assets are recorded based on the differences between the carrying amount of assets and liabilities in the consolidated balance sheet and their tax basis using income tax rates substantively enacted at the balance sheet date. The effect of change in rates on future income tax liabilities and assets is recognized in the period in which the change occurs. A valuation allowance is recorded against any future income tax assets if it is more likely than not that the asset will not be realized.

(j) Stock-based compensation:

During the year ended December 31, 2004 the Company retroactively adopted the amended standard with respect to stock-based compensation (see note 2(c)), which requires the use of the fair value method of valuing all stock options granted and other stock-based payments whether they be to employees, directors or non-employees. Under the fair value method, a compensation cost is measured at fair value method for stock options granted at the grant date and expensed over the vesting period with a corresponding increase to contributed surplus. Upon the exercise of the stock options, consideration paid together with the amount previously recognized to contributed surplus is recorded as an increase to share capital.

(k) Flow-through shares:

The tax attributes of expenditures financed by the issuance of flow-through shares are renounced to investors in accordance with income tax legislation. Share capital issued is recorded on the date of issue net of estimated benefits renounced to investors with a corresponding future tax liability for the tax benefits renounced to investors.

(l) Cash equivalents:

The Company considers all highly liquid investments with a maturity of three months or less at the time of purchase to be cash equivalents and therefore classifies them with cash.

1. Significant accounting policies (continued):

(m) Earnings per share:

Basic net earnings per common share is computed by dividing net earnings from operations by the weighted average number of common shares outstanding for the period. Diluted per share amounts reflect the potential dilution that could occur if securities or other contracts to issue common shares were exercised or converted to common shares. The treasury stock method is used to determine the dilutive effect of stock options and other dilutive instruments. Under the treasury stock method, only options for which the exercise price is less than the market value impact the dilution calculations.

(n) Use of estimates:

The amounts recorded for the depletion and depreciation of petroleum and natural gas properties and for the determination of asset retirement obligations are based on estimates. The ceiling test calculation and the goodwill impairment test are based, in part, on estimates of proved reserves, production rates, oil and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effects of changes in such estimates in future years on financial statements could be significant.

2. Change in accounting policies:

(a) Full cost accounting guideline:

Effective January 1, 2004 the Company adopted the new Canadian accounting guideline for the full cost method of accounting for oil and gas entities. The recoverability of a cost centre is tested by comparing the carrying value of the cost centre to the sum of the undiscounted cash flows expected from the cost centre's use and eventual disposition. If the carrying value is unrecoverable the cost centre is written down to its fair value using the expected present value approach. This approach incorporates risks and uncertainties in the expected future cash flows which are discounted using a risk free rate. The cash flows are estimated using expected future product prices and costs. The adoption of this guideline had no effect on the Company's financial results.

Prior to January 1, 2004, the Company applied a ceiling test to ensure capitalized costs did not exceed the aggregate of the cost of the unproved properties and undiscounted future net revenues of proved reserves at year end commodity prices less future administrative, financing and income tax expenses.

2. Change in accounting policies (continued):

(b) Asset retirement obligations:

Effective January 1, 2004, the Company retroactively adopted the new standard "Asset Retirement Obligations". This standard requires the recognition of the fair value of obligations associated with the retirement of tangible long-lived assets be recorded in the period the asset is put into use, with a corresponding increase to the carrying amount of the related asset. The obligations recognized are statutory, contractual or legal obligations. The liability is accreted over time and the accretion is included in depletion, depreciation and accretion expense. The costs capitalized to the related assets are amortized to earnings in a manner consistent with the depreciation, depletion and amortization of the underlying asset. Actual costs incurred upon the settlement of asset retirement obligations are charged against the asset retirement obligation. The impact of the adoption on prior periods was as follows:

Consolidated Balance Sheet as at December 31, 2003:

	As Reported	Change	As Restated
Asset:			
Property, plant and equipment	$35,955,362	$ 284,271	$36,239,633
Liabilities and shareholders' equity:			
Future income taxes	6,905,115	68,573	6,973,688
Asset retirement obligations	–	377,894	377,894
Provision for site restoration	274,078	(274,078)	–
Retained earnings	20,703,810	111,882	20,815,692

Consolidated Statement of Earnings and Retained Earnings

	Year ended December 31, 2003		
	As Reported	Change	As Restated
Depletion and depreciation	$ 4,896,905	$ (48,836)	$4,848,069
Accretion	–	27,992	27,992
Depletion, depreciation and accretion	4,896,905	(20,844)	4,876,061
Future income taxes	4,960,748	7,921	4,968,669
Net earnings	19,094,825	12,923	19,107,748

2. Change in accounting policies (continued):

Prior to January 1, 2004, the Company provided for future site restoration and abandonment costs over the life of the proved reserves on a unit-of-production basis. The charge was recorded in depletion and depreciation expense and the liability was recorded net of actual costs incurred. Had the Company continued to provide for future site restoration and abandonment costs over the life of the proved reserves on a unit-of-production basis, the provision for site restoration for the year ended December 31, 2004 would have been $301,000, the provision for depletion and depreciation would have been $15,327,000, future income taxes would have been $1,646,000 and net earnings would have been $2,366,000.

(c) Stock-based compensation:

Effective January 1, 2004 the Company retroactively adopted the amended standard with respect to stock-based compensation, which requires the use of the fair value method for valuing all stock options granted whether they be to employees, directors or non-employees. As a result of adopting this amended standard, the Company recognized an expense for all options granted. As such, stock-based compensation expense recorded totalled $102,450 during the year ended December 31, 2003 with a decrease in net earnings and a corresponding increase in contributed surplus. A decrease in retained earnings of $12,337 and a corresponding increase in contributed surplus was made relating to compensation expense for the year ended December 31, 2002.

3. Accounts receivable:

As at December 31, 2004 accounts receivable included a loan due from an officer of the Company totalling $100,000 plus accrued interest of $17,000 (December 31, 2003 - $100,000). The loan bears interest at 4.75% compounded annually per annum, is payable on demand and is secured by the pledge of 57,143 Class A common shares of the Company.

4. Property, plant and equipment:

2004	Cost	Accumulated depletion and depreciation	Net book value
Petroleum and natural gas properties	$ 156,534,374	$22,438,767	$ 134,095,607
Office equipment and computers	353,078	166,488	186,590
	$ 156,887,452	$22,605,255	$ 134,282,197
2003			
Petroleum and natural gas properties	$ 43,816,390	$ 7,699,398	$ 36,116,992
Office equipment and computers	242,879	120,238	122,641
	$ 44,059,269	$ 7,819,636	$ 36,239,633

At December 31, 2004, approximately $13,000,000 (2003 - $6,400,000) of unproved properties were excluded from the depletion calculation. Future development costs included in the depletion and depreciation calculation totalled $9,500,000 (2003 - $3,900,000) at December 31, 2003. During the year ended December 31, 2004 overhead applicable to acquisition, development and exploration activities in the amount of approximately $295,000 (2003 - $176,000) was capitalized to petroleum and natural gas properties.

As at December 31, 2004, property, plant and equipment includes $1,240,000 (December 31, 2003 - $285,000), net of accumulated depletion related to asset retirement obligations.

The Company performed a ceiling test at December 31, 2004 to assess the recoverable value of property, plant and equipment and other assets. The oil and gas future prices are based on the commodity price forecast of our independent reserve evaluators.

The following table summarizes the benchmark prices used in the ceiling test calculation. The Canadian dollar prices have been adjusted for commodity quality differentials specific to the Company. Based on these assumptions, the undiscounted value of future net revenues from proved reserves exceeded the carrying value of property, plant and equipment at December 31, 2004.

	WTI Oil ($U.S./bbl)	Foreign exchange rate	Edmonton Light Crude Oil ($Cdn/bbl)	AECO Gas ($Cdn/mmbtu)
2005	42.00	0.82	45.72	7.01
2006	40.00	0.82	44.08	6.76
2007	37.50	0.82	41.26	6.46
2008	35.00	0.82	38.45	6.15
2009	33.00	0.82	35.97	5.85
Prices escalate thereafter at approximately 1% to 2% per annum				

5. Long-term investments:

(a) Investment in In Depth Resources Ltd.:

At December 31, 2004 the Company's long-term investment totalling $1,000,000 was comprised of 960,000 common shares of In Depth Resources Ltd., a private oil and gas company in which the president of the Company is a director. The investment represents approximately 10% of the outstanding common shares of In Depth Resources Ltd. The Company has a right of first refusal to participate in certain prospects generated by In Depth Resources Ltd. At December 31, 2003 the Company's long-term investment was comprised of 200,000 flow-through common shares of In Depth Resources Ltd., which were acquired during the year ended December 31, 2003 at a cost of $240,000.

(b) Investment in Monolith Oil Corp.:

During the year ended December 31, 2003, the Company sold its investment in Monolith Oil Corp., a private oil and gas company for a gain totalling $17,439,000. Consideration received on the disposition of the investment in Monolith Oil Corp. consisted of $14,202,000 of cash or cash equivalents and a secured debenture totalling $3,737,000 bearing interest at 9% per annum, payable monthly. The debenture was repaid in its entirety in January 2004. The debenture was secured but subordinate to the purchaser's secured credit facility. During the year ended December 31, 2004, proceeds totalling $350,000 relating to the sale of its investment in Monolith Oil Corp. resulting from the resolution of various contingent matters was recorded.

During the year ended December 31, 2003, the Company received a dividend of approximately $2,100,000 from its investment in Monolith Oil Corp.

6. Taxes:

The provision for income taxes differs from the result that would be obtained by applying the combined Canadian Federal and Provincial income tax rate of approximately 38.6% (2003 – 40.6%) to earnings before taxes. The difference results from the following:

	2004	2003
Effective tax rate	38.6%	40.6%
Computed expected income taxes	$ 1,915,222	$ 9,808,435
Add (deduct):		
Non-deductible crown payments, net of Alberta Royalty Tax Credits	2,494,261	804,326
Resource allowance	(2,146,359)	(1,053,442)
Non-taxable portion of capital gains	(70,164)	(3,539,029)
Stock-based compensation	153,117	41,000
Capital taxes	185,000	70,394
Change in tax rate	(746,077)	(249,023)
Non-taxable dividend	-	(843,598)
	$ 1,785,000	$ 5,039,063

6. Taxes (continued):

The components of the net future income tax liability at December 31, 2004 and 2003 are as follows:

	2004	2003
Future income tax assets:		
Asset retirement obligations	$ 621,727	$ 125,000
Attributed royalty income deductible for provincial taxes	234,040	73,283
Share issue and financing costs	648,088	35,000
	1,503,855	233,283
Future income tax liabilities:		
Property, plant and equipment	(21,876,595)	(7,158,227)
Long-term investments	(46,344)	(48,744)
	(21,922,939)	(7,206,971)
Net future income tax liability	$(20,419,084)	$(6,973,688)

Corporate tax returns are subject to assessment by Canada Revenue Agency in the normal course of business. The result of any assessments will be accounted for as a charge to net earnings in the period in which they are realized.

7. Share capital:

(a) Authorized:

(i) an unlimited number of Class A common shares without par value; and

(ii) an unlimited number of Class B common shares without par value issuable in series. The Class B common shares are non-voting and are not entitled to the receipt of dividends.

7. Share capital (continued):

(b) Shares issued:

	2004		2003	
	Number	Amount	Number	Amount
Class A common shares:				
Balance, beginning of year	13,195,083	$13,454,933	11,827,106	$ 13,365,606
Issued for cash	1,200,000	6,000,000	57,143	100,131
Shares issued for services performed	12,500	62,500	-	-
Conversion of Class B shares	-	-	1,310,834	131
Flow-through shares issued	800,000	4,800,000	–	–
Share issue costs less tax effect of $37,800	-	(70,200)	–	(10,935)
Balance, end of year	15,207,583	$24,247,233	13,195,083	$13,454,933
Class B common shares:				
Balance, beginning of year	1,270,833	157	2,721,667	$ 288
Issued for cash	-	-	-	-
Conversion of Class B shares	-	-	(1,310,834)	(131)
Cancelled	-	-	(140,000)	–
Balance, end of year	1,270,833	$ 157	1,270,833	$ 157
Special Warrants:				
Balance, beginning of year	-		-	$ -
Issued for cash	3,300,000	29,700,000	-	-
Share issue costs less tax effect of $601,804	-	(1,117,632)	-	-
Balance, end of year	3,300,000	$28,582,368	-	$ -
Total		$52,829,758		$13,455,090

On February 3, 2005 the Company filed Articles of Amendment to amend the provisions of the series 1 class B shares and as such, the series 1 class B shares were automatically converted into class A common shares on February 4, 2005. On February 15, 2005 the Company declared a stock dividend in the amount of approximately $6,970,000 which resulted in 0.047 of a class A common share being issued for each issued and outstanding class A common share and each class A common share issuable upon the exercise of each issued and outstanding special warrant. This resulted in the issuance of 774,490 class A common shares at a price of $9.00 per share.

As at December 31, 2004 the Company had incurred all expenditures required to be committed relating to obligations pursuant to the terms of the flow through shares issued.

7. Share capital (continued):

On October 20, 2004 the Company issued 3,300,000 special warrants at a price of $9.00 per special warrant for gross proceeds totalling $29,700,000. Costs associated with the issuance of the special warrants totalled approximately $1,719,000 including a commission received by the agent equal to 5.5% of the gross proceeds from the sale of the special warrants for an aggregate fee of approximately $1,634,000. Each special warrant entitled the holder thereof to acquire 1.047 common shares at no additional cost on that date which is five business days following the date upon which a receipt for the final version of a prospectus is issued by the appropriate securities commissions.

On receipt of the final prospectus 3,455,105 Class A common shares were issued upon the exercise of the special warrants (see note 14).

(c) Per Share Amounts:

Weighted average number of common shares outstanding	2004	2003
Basic	15,994,912	14,465,916
Dilutive effect of options	276,485	97,574
Diluted	16,271,397	14,563,490

(d) Stock options:

The Company has a stock option plan to provide options for directors, officers and employees to purchase Class A common shares of the Company. The stock options are exercisable over six years, with a vesting period over four years.

The following summarizes the options outstanding at December 31, 2004 and 2003:

	2004		2003	
	Number of options	Weighted average exercise price	Number of options	Weighted average exercise price
Balance, beginning of year	530,000	$ 2.84	170,000	$ 2.60
Granted	1,012,155	6.53	360,000	2.94
Balance, end of year	1,542,155	$ 5.26	530,000	$ 2.84
Exercisable, end of year	175,000	$ 2.78	42,500	$ 2.60

7. Share capital (continued):

	Options outstanding			Options Exercisable	
Range of exercise price	Number outstanding December 31, 2004	Weighted average remaining contractual life (years)	Weighted average exercise price	Number exercisable December 31, 2004	Weighted average exercise price
$ 2.60	345,000	3.8	$ 2.60	128,750	$ 2.60
$ 3.25 - $3.50	235,000	4.6	3.34	46,250	3.29
$ 4.50 - $5.00	535,000	5.4	4.98	-	-
$ 8.10 - $9.00	427,155	5.9	8.82	-	-
	1,542,155	5.1	$ 5.26	175,000	$ 2.78

The fair value of stock options granted during the year ended December 31, 2004 and December 31, 2003 was estimated using the Black-Scholes option pricing model with the following assumptions:

	2004	2003
Dividend yield	0%	0%
Expected volatility	50%	25%
Risk free rate of return	4.5%	4.5%
Expected option life	4 years	4 years
Weighted average fair market value per option	$3.48	$1.00

(e) Contributed surplus:

	2004	2003
Balance, beginning of year	$ 114,787	$ 12,337
Stock based compensation expense	396,471	102,450
Balance, end of year	$ 511,258	$ 114,787

8. Bank indebtedness:

At December 31, 2004 the Company had available a revolving demand facility to a maximum of $35,000,000 (December 31, 2003 - $12,000,000) and non-revolving demand facility to a maximum of $11,400,000 (December 31, 2003 - $nil) with a Chartered Canadian bank. The revolving facility bears interest at the bank's prime rate plus 0.25% per annum and the non-revolving demand facility bears interest at the bank's prime rate plus 3.75% per annum. Any balance outstanding on the non-revolving demand facility is to be repaid by March 31, 2005. As at December 31, 2004, $23,422,000 (December 31, 2003 - $nil) was outstanding under the revolving demand facility payable at an interest rate of 4.04% per annum and $11,400,000 (December 31, 2003 - $nil) was outstanding under the non-revolving demand facility payable at an interest rate of 5.57% per annum.

The facility is secured by a general security agreement with a floating charge covering land registered in Alberta, British Columbia and Saskatchewan.

9. Asset retirement obligations:

At December 31, 2004, the estimated total undiscounted amount required to settle asset retirement obligations was $3,100,000 which will be incurred between 2005 and 2025. This amount has been discounted using an annual credit adjusted risk-free interest rate of 8.0 percent per annum and an inflation rate of 2.0 per cent per annum.

Charges to asset retirement obligations were as follows:

	2004	2003
Asset retirement obligations, beginning of year	$ 377,894	$ 129,530
Liabilities acquired	950,000	–
Liabilities incurred	1,144,110	220,372
Liabilities disposed of	(600,000)	–
Accretion	101,731	27,992
Asset retirement obligations, end of year	$ 1,973,735	$ 377,894

10. Changes in non-cash working capital:

(a) Changes in non-cash working capital balances:

	2004	2003
Changes in non-cash working capital:		
Accounts receivable	$ (7,852,799)	$ 953,482
Prepaid expenses and deposits	(330,017)	5,413
Accounts payable and accrued liabilities	17,666,912	(4,165,637)
	9,484,096	(3,206,742)
Changes in non-cash working capital relating to investing	(12,424,396)	1,005,837
Changes in non-cash working capital relating to operations	$ (2,940,300)	$(2,200,905)

(b) Cash payments:

The following cash payments were received (paid):

	2004	2003
Dividends received	$ -	$ 2,076,084
Interest received (paid)	(1,651,300)	137,176
Taxes paid	(60,000)	(28,000)

11. Financial Instruments:

(a) Commodity price risk management:

The Company entered into commodity swap agreements during the year ended December 31, 2004. The details of these agreements are as follows:

Commodity	Notional Volumes	Contract Term	Fixed Price
Crude Oil	500 barrels per day	July 1, 2004 to December 31, 2004	CDN $44.00 per barrel
Crude Oil	700 barrels per day	January 1, 2005 to December 31, 2005	CDN $47.20 per barrel

The 700 barrel per day crude oil swap agreement had an unrealized loss as at December 31, 2004 of approximately $1.0 million.

11. Financial Instruments (continued):

(b) Credit risk:

The Company's accounts receivable are with customers and joint venture partners in the petroleum and natural gas industry and are subject to normal industry credit risks. Purchasers of the Company's natural gas, crude oil and natural gas liquids are subject to an internal credit review to minimize the risk of non-payment. During the year ended December 31, 2004, approximately 85% (December 31, 2003 – 90%) of the Company's oil and gas revenues were sold to three customers.

(c) Fair values:

The carrying values of the Company's financial assets and liabilities, with the exception of the Company's long-term investments (see note 5), approximated their fair values as at December 31, 2004 and 2003. The fair value of the Company's long-term investments was considered undeterminable due to the inability to apply a valuation method or obtain market prices. As noted in note 5, during the year ended December 31, 2003 the Company sold its investment in Monolith for a gain of approximately $17,439,000.

12. Commitment:

The Company is committed to a lease for office space annually as follows:

2005	$ 329,000
2006	330,000
2007	340,000
2008	345,000
2009	175,000

13. Acquisition of Rubicon Energy assets:

In March 2004, the Company acquired 50% of the issued and outstanding shares of Rubicon Energy Corporation ("Rubicon"), an oil and gas company. The acquisition was accounted for by the purchase method of accounting with the results of operations included from the date of acquisition. The allocation to the fair value of the assets and liabilities was as follows:

13. Acquisition of Rubicon Energy assets (continued):

Net assets acquired and liabilities assumed:

Property, plant and equipment	$ 51,151,000
Goodwill	14,081,000
Working capital deficiency	(6,314,000)
Bank indebtedness	(3,394,000)
Asset retirement obligations	(950,000)
Future income taxes	(12,485,000)
	$ 42,089,000

Consideration was comprised of:

Purchase of Rubicon common shares for cash	$ 41,810,000
Transaction costs	279,000
	$ 42,089,000

14. Subsequent events:

(a) Credit facility:

In February 2005 a new banking arrangement was entered into by the Company with Canadian financial institutions. The facilities consisted of a $45 million revolving term credit facility, a $10 million demand operating credit facility and a $25 million non-revolving, non-extendible term credit facility. The $45 million revolving term facility revolves until May 31, 2005 unless it is extended for a 364-day period. The $25 million non-revolving, non-extendible term credit facility shall be repaid no later than May 31, 2005. The revolving term credit facility bears interest at the lenders' prime rate plus 0.25% per annum. The non-revolving, non-extendible term credit facility and the demand operating credit facility bears interest at the lenders' prime rate plus 1.75% per annum. The facilities are secured by a general security agreement and a first floating charge over all of the Company's assets.

14. Subsequent events (continued):

(b) Initial public offering:

Pursuant to an underwriting agreement dated March 24, 2005 between the Company and certain underwriters, the Company sold to the underwriters 4,000,000 common shares at a price of $18.00 per share for gross proceeds totalling $72,000,000. Costs associated with the issuance of the common shares are estimated to be approximately $4,342,200 including the underwriters' fee of $3,742,200 and other expenses.

On April 5, 2005, common shares distributed pursuant to an initial public offering and the common shares issuable upon exercise of the outstanding special warrants were listed on the Toronto Stock Exchange.

(c) Plan of Arrangement:

On April 6, 2005, the Company announced that it entered into a merger agreement with Vaquero Energy Ltd. ("Vaquero") whereby the Company would acquire all of the issued and outstanding shares of Vaquero pursuant to a Plan of Arrangement to be approved by the Vaquero shareholders no later than June 30, 2005.

Under the Plan of Arrangement, shareholders of Vaquero will receive 0.391 Class A common shares of the Company for each common share of Vaquero held. It is anticipated that on closing the Company will be required to issue approximately 19.5 million shares to the Vaquero shareholders. On April 5, 2005, the last trading day prior to the announcement of the proposed arrangement, the closing prices of the Vaquero shares and the Highpine shares on the Toronto Stock Exchange were $7.84 and $19.50 respectively. Transaction costs on the Company's acquisition are estimated to be approximately $1.5 million. The acquisition will be accounted for using the purchase method of accounting whereby the net assets and liabilities acquired will be recorded at their fair values and the results of operations will be recorded from the date of closing of the transaction.

15. Contingency:

On December 14, 2004 the Company was granted a license from the Alberta Energy and Utilities Board (the "AEUB") relating to the expansion of an existing facility. On December 15, 2004 a notice of objection was filed with the AEUB by a corporation which is a joint lease owner where the facility is being constructed. To date, the AEUB has not ruled on the merits of the notice of objection. Although management of the Company is of the view that the objection submitted by the corporation is without merit and will continue to defend the interests of the Company in the facility, it is possible that the AEUB may render a decision in this matter which would have an adverse effect on the Company and its processing capabilities in an area which is significant to the Company.