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HIGHPINE
OIL & GAS LIMITED

ANNUAL INFORMATION FORM

for the year ended December 31, 2005

March 27, 2006

TABLE OF CONTENTS

CONVENTIONS

Certain terms used herein are defined under the heading "Glossary of Terms".

Unless otherwise indicated, references herein to "$" or "dollars" are to Canadian dollars.

Unless the context otherwise requires, references herein to "Highpine" or the "Corporation" include Highpine, HAC, Pino Alto, Rubicon, Highpine Partnership, Highpine Energy, 665162 and White Fire.

Certain other terms used herein but not defined herein are defined in NI 51-101 and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101.

Unless otherwise specified, information in this Annual Information Form is as at the end of the Corporation's most recently completed financial year, being December 31, 2005.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements contained in this Annual Information Form and the documents incorporated by reference herein constitute forward-looking statements. The use of any of the words "anticipate", "continue", "estimate", "expect", "may", "will", "project", "should", "believe" and similar expressions are intended to identify forward-looking statements. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. The Corporation believes that the expectations reflected in these forward-looking statements are based on reasonable assumptions but no assurance can be given that these expectations will prove to be correct and the forward-looking statements included in this Annual Information Form and the documents incorporated by reference herein should not be unduly relied upon. These statements speak only as of the date of this Annual Information Form or as of the date specified in the documents incorporated by reference herein.

In particular, this Annual Information Form and the documents incorporated by reference herein contains forward-looking statements pertaining to the following:

- the performance characteristics of the Corporation's oil and natural gas properties;
- oil and natural gas production levels and the sources of their growth;
- capital expenditure programs;
- the estimated quantity of oil and natural gas reserves and recovery rates;
- projections of commodity prices and costs;
- supply and demand for oil and natural gas;
- planned construction and expansion of facilities;
- drilling plans;
- availability of rigs, equipment and other goods and services;
- procurement of drilling licenses;
- reserve life;
- plans for and results of exploration and development activities;
- expectations regarding the Corporation's ability to raise capital and to continually add to reserves through acquisitions, exploration and development;
- treatment under governmental regulatory regimes and tax laws; and
- realization of the anticipated benefits of acquisitions and dispositions.

The Corporation's actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this Annual Information Form and the documents incorporated by reference herein:

- general economic, market and business conditions in Canada, the United States and globally;
- volatility in market prices for oil and natural gas;
- risks inherent in oil and natural gas operations;
- uncertainties associated with estimating oil and natural gas reserves;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands, skilled personnel and services;
- unanticipated operating events which can reduce production or cause production to be shut in or delayed;

- incorrect assessments of the value of acquisitions;
- geological, technical, drilling and processing problems;
- actions by governmental authorities, including increases in taxes;
- the availability of capital on acceptable terms;
- fluctuations in foreign exchange or interest rates and stock market volatility;
- failure to obtain industry partner and other third party consents and approvals, when required; and
- the other factors discussed under "Risk Factors" in this Annual Information Form.

Statements relating to "reserves" or "resources" are by their nature forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and resources described can be profitably produced in the future. These factors should not be construed as exhaustive. The Corporation undertakes no obligation to update or revise any forward-looking statements except as required by applicable securities laws.

DOCUMENTS INCORPORATED BY REFERENCE

The business acquisition report of Highpine in the form of the information circular-proxy statement of Vaquero dated April 29, 2005 relating to the annual and special meeting of the securityholders of Vaquero held on May 31, 2005 to approve the Vaquero Arrangement (the "**Vaquero Business Acquisition Report**") filed with various securities commissions or similar authorities in the provinces of Canada, is specifically incorporated by reference into, and forms part of, this Annual Information Form and has been filed on SEDAR at www.sedar.com.

CORPORATE STRUCTURE

Name, Address and Incorporation

Highpine Oil & Gas Limited

Head Office:
Suite 4000, 150 – 6th Avenue S.W.
Calgary, Alberta T2P 3Y7

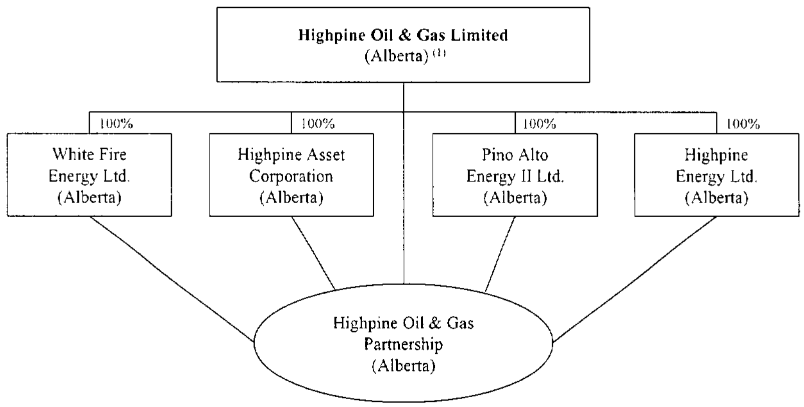
Registered Office:
Suite 1400, 350 – 7th Avenue S.W.
Calgary, Alberta T2P 3N9

Highpine was incorporated under the name 779573 Alberta Inc. pursuant to the ABCA on April 2, 1998. On April 9, 1998, Highpine filed Articles of Amendment to change its name to "Highpine Oil & Gas Limited". On December 14, 1999, Highpine filed Articles of Amendment to remove the "private company" provisions from its Articles. On December 23, 1999, Highpine filed Articles of Amendment to reorganize its share capital to provide for the issuance of an unlimited number of first preferred shares issuable in series and an unlimited number of second preferred shares issuable in series. On February 2, 2000, Highpine filed Articles of Amendment to reorganize its share capital to consist of an unlimited number of Common Shares and an unlimited number of Class B Shares, issuable in series. On February 17, 2000, Highpine filed Articles of Amendment to reorganize its share capital to fix the rights, privileges, restrictions and conditions of an initial series of 3,000,000 Class B Shares, designated as Series 1 Class B Shares. On February 18, 2000, Highpine filed Articles of Amendment to effect a split its then outstanding Common Shares on a 1.256440-for-one basis. On February 3, 2005, Highpine filed Articles of Amendment to amend the provisions of the Series 1 Class B Shares to provide for the automatic conversion of such shares into Common Shares on February 4, 2005. On February 7, 2005, Highpine filed Articles of Amendment to cancel the Series 1 Class B Shares. Unless otherwise stated, disclosure in this Annual Information Form of the share capital of Highpine is presented after giving effect to the foregoing amendments to the Articles of Highpine.

Intercorporate Relationships

Highpine has five wholly-owned subsidiaries, Pino Alto, HAC, Highpine Energy, 665162 and White Fire. Pino Alto, HAC, Highpine Energy and White Fire were incorporated under the ABCA on April 12, 2000, February 24, 2004, May 5, 1995 and March 14, 2005, respectively. 665162 was incorporated under the *Business Corporations Act* (British Columbia) on March 4, 2003. Highpine also owns 50% of the issued and outstanding common shares of Rubicon, which was formed by Articles of Amalgamation filed pursuant to the ABCA on March 5, 2004. In addition, Highpine is the managing partner of Highpine Partnership, which was formed under the laws of Alberta pursuant to a partnership agreement dated as of February 18, 2003, as amended, between the Corporation and Pino Alto. Substantially all of Highpine's producing assets have been contributed to Highpine Partnership with the exception of Highpine's Joffre area properties, which are held by Highpine, and certain Pembina area properties, which are held by Highpine and HAC. 665162 and Rubicon are inactive subsidiaries in which the total assets of each of 665162 and Rubicon on an individual basis do not exceed 10% of the consolidated assets of the Corporation.

The following diagram illustrates the corporate structure of the Corporation, the percentage of voting securities owned and the jurisdiction of incorporation or formation of Highpine and its subsidiaries as at the date of the Annual Information Form which gives effect to the completion of the White Fire Arrangement.



Notes:

(1) Highpine indirectly owns 100% of Highpine Partnership.
(2) Highpine has two inactive subsidiaries, 100% owned 665162 and 50% owned Rubicon.

GENERAL DEVELOPMENT OF THE BUSINESS

Historical Development of the Business

The following is a summary of the development of Highpine's business over the last three completed financial years.

March 2003 – Highpine participated in the Pembina Nisku II Pool discovery at 10-1-49-9 W5M, which is located approximately 15 kilometres west of Drayton Valley, Alberta.

September 2003 – Highpine sold its $1.0 million investment of shares of Monolith Oil Corp., a private oil and gas company, for net proceeds of approximately $18 million.

March 2004 – Highpine indirectly acquired an undivided 50% interest in all of the assets and liabilities of Rubicon for approximately $51 million.

July 2004 – Highpine completed a private placement of 1,200,000 Common Shares, at a price of $5.00 per share, and 800,000 "flow-through" Common Shares, at a price of $6.00 per share, for aggregate gross proceeds of $10.8 million.

October 2004 – Highpine completed a private placement of 3,300,000 Special Warrants at a price of $9.00 per Special Warrant for aggregate gross proceeds of $29.7 million.

December 2004 – Highpine commissioned the Joffre Gas Plant, which is 100% owned and operated by Highpine and capable of processing in excess of 10 mmcf/d of raw natural gas. Highpine received AEUB approval to expand the existing Violet Grove sour facility to a 15,000 bbls/d battery in the Pembina area in which Highpine owns an approximate 55% interest. Construction of the Violet Grove Battery was completed and commissioned in May 2005.

April 2005 – Highpine completed the Initial Public Offering on April 5, 2005. Upon completion of the Initial Public Offering, Highpine's Common Shares were listed and posted for trading on the TSX under the symbol "HPX". The net proceeds of the Initial Public Offering were used to temporarily reduce bank indebtedness and to fund the Corporation's exploration and development activities, and for general working capital purposes. On April 6, 2005, Vaquero announced that the 9-35-48-8 W5M exploration well, which is now 100% owned by Highpine encountered approximately 26 metres (85 feet) of hydrocarbons in the Nisku formation. This well is currently producing approximately 2,000 boe/d.

May 2005 – Highpine acquired all of the issued and outstanding common shares of Vaquero pursuant to the Vaquero Arrangement. See "General Development of the Business – Significant Acquisitions and Recent Developments".

Significant Acquisitions and Recent Developments

Vaquero Arrangement

On May 31, 2005 Highpine acquired all of the issued and outstanding common shares of Vaquero pursuant to the Vaquero Arrangement for consideration of $399.4 million comprised of 19.5 million Common Shares with an ascribed value of $350.9 million, the assumption of bank debt and working capital deficiency of $48.1 million and acquisition costs of $0.4 million. Further information respecting the Vaquero Arrangement is contained in the Vaquero Business Acquisition Report which is incorporated by reference and forms part of this Annual Information Form.

White Fire Arrangement

On February 21, 2006, Highpine acquired all of the issued and outstanding common shares of White Fire pursuant to the White Fire Arrangement. Highpine issued 4,089,087 Common Shares to former shareholders of White Fire.

Upon completion of the White Fire Arrangement, Mr. Ken Woolner joined the board of directors of Highpine and Mr. Robert Rosine, Mr. Robert Fryk, Mr. Rob Pinckston and Mr. Dave Humphreys, senior officers of White Fire, joined the management of Highpine in the following capacities: Robert Rosine – Executive Vice President, Corporate Development, Robert Fryk – Senior Vice President, Engineering and Operations, Dave Humphreys – Vice President, Operations and Rob Pinckston – Vice President, W5M Gas.

Bought Deal Equity Financing

On February 23, 2006, Highpine completed a bought deal equity financing pursuant to which Highpine issued 4,300,000 Common Shares at a price of $23.40 per share for gross proceeds of $100.62 million (the "**Bought Deal Equity Financing**"). The net proceeds of the Bought Deal Equity Financing were used to temporarily reduce bank indebtedness, which is expected to be redrawn, as needed to fund the Corporation's capital expenditure program in 2006 and for general working capital purposes.

DESCRIPTION OF THE BUSINESS

General

Highpine is an Alberta based oil and gas corporation with an aggressive activity plan for future growth. The Corporation is engaged in the exploration for, and the acquisition, development and production of, natural gas and crude oil in western Canada. Highpine's business plan contemplates that the Corporation will pursue exploration, development and exploitation drilling, complemented with property or corporate acquisitions exhibiting synergy in lands, facilities, production and operating efficiencies. The vast majority of Highpine's current operations are in the Province of Alberta.

Business Plan and Growth Strategies

The business plan of Highpine is to focus on sustainable and profitable growth in production, cash flow from operations and net asset value. To accomplish this, Highpine's management pursues an integrated growth strategy, including exploration, development and exploitation drilling, complemented with acquisitions of properties in specific areas where further exploration, development or exploitation opportunities exist. Management believes that "full cycle" exploration and exploitation of oil and natural gas is the most efficient way to create "true" shareholder value (that is, generate significant rates-of-return on invested capital), in the current oil and natural gas environment. Management internally generates exploration, development and exploitation opportunities, starting with thorough detailed regional mapping. Once trends and areas of interests have been established, Highpine accumulates land in core areas by way of crown/freehold land acquisitions, industry farm-ins and joint ventures. To date, Highpine has chosen to concentrate its activities and focus to Alberta. Highpine's production is derived from the following three core operating and exploration areas:

Pembina/Nisku – Central Alberta:	These assets target oil and natural gas in the Nisku, Glauconitic, Rock Creek, Ellerslie and Pekisko zones.
West Central Alberta Gas Fairway:	These assets target liquids-rich natural gas in the Edmonton, Notikewin, Rock Creek, Nordegg, Belly River, Viking, Glauconitic and Ellerslie zones. In addition, Highpine is evaluating coal bed methane opportunities in this area.
Bantry/Retlaw – Southern Alberta:	These assets target lower risk oil and natural gas exploitation in the Mannville zone.

Highpine has production, shut-in volumes (including several oil and natural gas new pool discoveries) and an inventory of prospects in each of its core areas. Highpine's activities range from lower risk development to high risk exploration. Highpine maintains ownership and/or operatorship of the key facilities and infrastructure serving its core operating and exploration areas.

Highpine's prospect and drilling inventory contains 176 total locations on lands in which Highpine has a significant working interest and which have been geophysically and geologically evaluated. There are 90 "firm" and 20 "contingent" locations within the Pembina/Nisku trend. This inventory represents four to five years worth of drilling for Highpine at the current pace. Highpine's business plan includes the addition to and expansion of such prospect and drilling inventory with a focus on longer term sustainable and profitable growth.

In 2005, Highpine's net capital expenditures were $153.6 million, excluding the acquisition of Vaquero. The Corporation participated in the drilling of 56 gross wells (36.4 net) and realized an overall drilling success rate of 63% on fully evaluated wells. In addition, the acquisition of Vaquero provided Highpine with significant production and landholdings and strategic facilities.

Highpine's capital budget for 2006 is approximately $160 million and includes the drilling of approximately 70 to 90 gross wells (50 to 60 net). Of the total budget, approximately $42 million is allocated to development drilling, approximately $69 million is allocated to exploration drilling (including undeveloped land acquisition and seismic programs) and approximately $49 million is allocated to facilities and tie-ins. By area, approximately $60 million is allocated to Pembina/Nisku (including the drilling of 20 gross wells and the construction of associated treating and gas gathering and conditioning systems), approximately $62 million is allocated to the West Central Alberta Gas Fairway (including the drilling of at least 50 gross wells and the associated wellsite and gathering facilities), approximately $23.5 million is allocated to high impact, minor and non-operated properties and approximately $14.5 million is allocated to maintenance capital. This capital program will be funded through a combination of cash flow, bank debt and the net proceeds of the Bought Deal Equity Financing.

Specialized Skill and Knowledge

Strong Management

Drawing on a collective experience of more than 200 years in the oil and gas business, Highpine's management team has a demonstrated track record of bringing together all of the key components to a successful exploration and production company: strong technical skills; expertise in planning and financial controls; ability to execute on business development opportunities; capital markets expertise; and an entrepreneurial spirit that allows Highpine to effectively identify, evaluate and execute on value-added initiatives. See "Directors and Executive Officers".

Competitive Conditions

Companies operating in the petroleum industry must manage risks which are beyond the direct control of company personnel. Among these risks are those associated with exploration, environmental damage, commodity prices, foreign exchange rates and interest rates.

The oil and natural gas industry is intensely competitive and Highpine will be required to compete with a substantial number of other corporations which may have greater technical or financial resources. With the maturing nature of the Western Canadian Sedimentary Basin, the access to new prospects is becoming more and more competitive and complex. Management believes that Highpine will be able to explore and develop new production and reserves with the objective of increasing its cash flow and reserve base.

Highpine will attempt to enhance its competitive position by operating in areas where its technical personnel are able to reduce some of the risks associated with exploration, production and marketing because they are familiar with the areas of operation.

Cycles

The Corporation's business is generally not cyclical. The exploration and development of oil and natural gas reserves is dependent on access to areas where production is to be conducted. Seasonal weather variation, including freeze-up and break-up affect access in certain circumstances.

Environmental Protection

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation. Compliance with such legislation can require significant expenditures or result in operational restrictions. Breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage and the imposition of material fines and penalties, all of which might have a significant negative impact on earnings and overall competitiveness. See "Industry Conditions – Environmental Regulation".

Employees

As at December 31, 2005, Highpine had 50 full-time employees and 10 consultants, all of whom were located at its office in Calgary except for 10 full-time employees that are located at the Drayton Valley field office.

Environmental, Health and Safety Policies

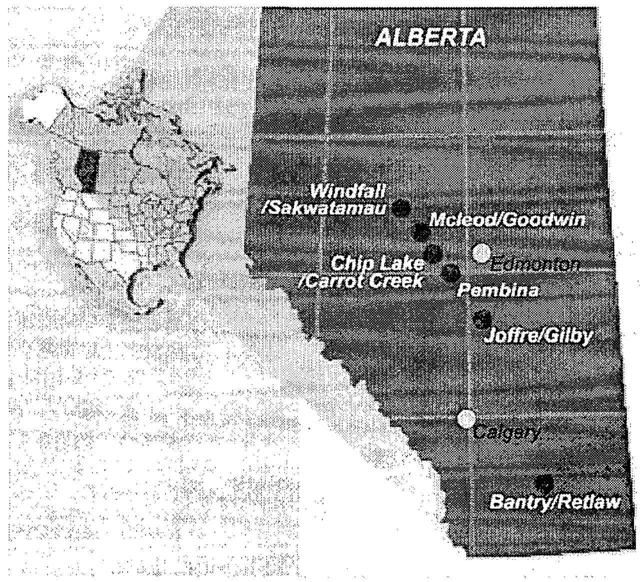
Environmental protection and employee health and safety are core values recognized and supported by the Corporation. The Corporation actively supports these areas by integrating the essential principles and practices through its environmental management systems and employee occupational health and safety programs. The Corporation ensures policies and procedures are fully integrated with and within all operating units by advising and educating employees, suppliers and contractors in the safe use, transportation, storage and disposal of products and materials. The Corporation promotes and enhances safety and environmental awareness and protection through the implementation and communication of the Corporation's environmental management and employee occupational health and safety programs policies and procedures. Effective committee structures are established in the Corporation's operations to allow for employee participation and development of Corporation policies and programs which provide employees with job orientation, training, instruction and supervision necessary to assist them in conducting their activities in an environmentally responsible and safe manner.

The Corporation develops emergency response teams and preparedness plans in conjunction with local authorities, emergency services and the communities it operates in to ensure prompt response to an environmental incident should it arise. Environmental assessments are undertaken for new projects or when acquiring new properties or facilities to identify, assess and minimize environmental risks and operational exposures. The Corporation conducts audits of operations to confirm compliance with internal standards and to stimulate improvement in practices where needed. Accurate documentation is maintained to support internal accountability and measure operational performance against recognized industry indicators to ensure the objectives of the policies and programs are achieved.

The Corporation also faces environmental, health and safety risks in the normal course of its operations due to the handling and storage of hazardous substances. The Corporation's environmental and occupational health and safety management systems are designed to identify, prevent and control such risks in the Corporation's business and ensure immediate action is taken to mitigate the extent of any environmental, health or safety impacts from such operations. A key aspect of these systems is the performance of annual environmental and occupational health and safety audits.

DESCRIPTION OF PRINCIPAL PROPERTIES

The following is a description of Highpine's principal oil and natural gas properties and minor exploration properties as at December 31, 2005. The term "net", when used to describe Highpine's share of production, means Highpine's working interest share of production before deducting royalties owned by others. Unless otherwise specified, gross, net acres, well count and production information are as at December 31, 2005. Reserve amounts are stated (before deduction of royalties) as at December 31, 2005, based on escalating costs and price assumptions and are derived from reserve information contained in the Highpine Paddock Report and White Fire Paddock Report. See "Statement of Reserves Data and Other Oil and Gas Information".



Pembina/Nisku – Central Alberta

The Pembina/Nisku property is located in the Drayton Valley area of Alberta approximately 100 kilometres southwest of Edmonton. The Pembina/Nisku property is Highpine's major property, producing approximately 3,927 boe/d, 82.5% in 2005 of which is oil and NGLs, and representing approximately 62.5% of Highpine's total 2005 production volumes. Highpine's property interests in Pembina/Nisku consist of working interests ranging from 10% to 100% and averaging 46% (proved reserves volume weighted). As at December 31, 2005, Highpine had an interest in 23 producing wells (11.9 net), six shut-in wells (1.6 net) as well as interests in several water source and injection wells associated with pressure maintenance schemes. The average Highpine working interest production from the property was approximately 9,800 boe/d for the first week of March 2006. Highpine operates 16 wells associated with this property. In addition, Highpine has an average 48.5% working interest on a combined basis in three oil batteries. All of Highpine's on stream production is gathered in flowlines connecting wells to central batteries. At the central batteries, produced oil, natural gas and water is separated. All of the production is pipeline connected and water is disposed of in water disposal wells.

The Pembina/Nisku property consists of 10,400 gross (4,620 net) acres of developed land and 112,000 gross (87,500 net) acres of undeveloped land.

The Highpine Paddock Report attributes proved plus probable reserves of 17.4 mmboe to Highpine's working interest in the Pembina/Nisku area. The Highpine Paddock Report attributes proved reserves of 10.7 mmboe to Highpine's working interest in the Pembina/Nisku area.

Highpine commenced activities in this area in November 2002 when the Corporation participated in the 9-30-49-8 W5M Nisku oil discovery. Highpine management viewed the 9-30-49-8 W5M Nisku prospect well as a "concept" well, whereby if successful, it would validate the potential for a geologically repeatable trend of Nisku reefs along a 70 mile long by 10 mile wide fairway. Subsequent to the successful 9-30-49-8 W5M Nisku oil discovery, which validated the "concept", Highpine captured a significant land position in this fairway, and has participated in several additional Nisku oil discoveries throughout 2003 to 2005. To date, Highpine has ownership in 18 discoveries in this area.

In May 2005, Highpine acquired Vaquero. Vaquero's assets included working interests in 11 joint Nisku oil pool discoveries, associated infrastructure and several Nisku oil prospects. The acquisition of Vaquero was considered by Highpine management to be complementary to Highpine's position in the trend. See "General Development of the Business – Significant Acquisitions and Recent Developments".

Infrastructure is very important in the Pembina/Nisku trend due to the "sour" nature of the production. The Rubicon Acquisition and the Vaquero Acquisition gave Highpine a 65% working interest in the Easyford Battery located on the northeast part of the trend. After an expansion, completed in the spring of 2004, this battery is capable of handling 9,000 bbls/d of sour oil (net capacity 5,850 bbls/d). To provide critical sour gas take-away capacity, Highpine joined a consortium of mid-streamers (companies whose business is the transportation and processing of hydrocarbons without ownership in same) and area oil and gas producers which include Keyera Energy Canada Partnership and Duke Energy Midstream Services Canada Ltd. and constructed an 80 kilometre pipeline, capable of carrying sour solution gas, or non-associated gas volumes to the Keyera Brazeau Gas Plant at 6-12-46-14 W5M, which is located approximately 170 kilometres southwest of Edmonton. Highpine has a 36% interest in this pipeline. Highpine's working interest in the Violet Grove Battery is 80% and Highpine is the operator. This battery is capable of handling 15,000 bbls/d (net capacity of 12,000 bbls/d). In October 2005, Highpine acquired a 15% interest in the Dominion Violet Grove Battery. The battery is capable of handling 19,000 bbls/d (net capacity of 2,850 bbls/d).

Highpine's undeveloped land base at Pembina/Nisku holds an inventory of approximately 90 gross (62.2 net) firm drilling locations. The average working interest is 69% in the firm locations. The Corporation also has approximately 20 gross (12 net) contingent drilling locations. These locations are to be drilled if certain of the firm wells are successful. The Corporation expects to drill approximately 15 to 20 wells per year thereby giving Highpine a four to five year inventory of drilling opportunities. The average cost, assuming no significant drilling problems, to drill and complete wells in the Pembina/Nisku area is approximately $1.5 to $3.0 million. Costs to tie-in wells is an additional $1.0 to $1.5 million. Highpine also has ongoing 3D seismic and land acquisition programs which are designed to identify additional drilling opportunities to add to this inventory in the Pembina/Nisku area.

The Pembina/Nisku play is very competitive as many companies are actively acquiring land, drilling wells and attempting to obtain facility access. Nisku oil is "sour" oil which requires longer lead times in licensing wells and obtaining approval for associated facilities to bring these wells on stream. Lack of sour fluid handling capacity in this area has resulted in a significant amount of production that has been drilled but not put on stream. It is anticipated that Highpine's current facility ownership position will allow for the Corporation's future production drilled on the Pembina/Nisku trend to come on stream in a more timely manner.

When Nisku pools are developed, the operator's preferred method of producing these wells are at the highest withdrawal rates possible. This maximizes the economic value of wells and allows the facilities to operate at the most efficient levels. Maximum production rates require AEUB approval or the granting by the AEUB of Good Production Practice ("**GPP**"). GPP is granted when, in the opinion of the AEUB, all stakeholders holding interests in the pool are treated equitably, and the unrestricted flow rates do not reduce ultimate reservoir recovery of oil. The Nisku zone is thought to have an active water drive providing varying degrees of reservoir pressure support. The extent of this support is unknown at this time. The AEUB and industry producers, including Highpine, are monitoring this situation on an ongoing basis. Highpine is injecting water in two Nisku pools at this time with a third expected shortly. Several of Highpine's Nisku pools have GPP or are being applied for. The AEUB will ultimately dictate reservoir operating conditions including the granting of GPP in potential new Nisku pools discoveries, possible recession of GPP, requirement for pressure maintenance (i.e., water injection), and/or specific production rates for individual Nisku wells or pools. It is Highpine's objective to maximize Nisku production; however, the foregoing factors will influence the Corporation's ability to do so. Further, future production forecasts may be positively and/or negatively impacted as a result of such factors.

West Central Alberta Gas Fairway

The West Central Alberta Gas Fairway property is located northwest of Edmonton, Alberta and trends approximately 200 miles southeast towards Red Deer. It includes natural gas properties in Joffre, Chip Lake, Windfall/Sakwatamau, McLeod/Goodwin, Ante Creek and Wilson Creek/Ferrier. The West Central Alberta Gas Fairway property is Highpine's second major property, producing approximately 1,600 boe/d in 2005 and representing approximately 25% of Highpine's total production volumes in 2005. Highpine's property interests in West Central Alberta Gas Fairway consist of working interests ranging from 7.5% to 100% and averaging 47% (proved reserves volume weighted). Highpine has an interest in 57 producing wells (35.2 net) and 23 shut-in wells (9.9 net). The average Highpine working interest production from the property was approximately 2,363 boe/d for the first week of March 2006, 80% of which was natural gas. In addition, Highpine has interests in three gas plants which process natural gas for Highpine and its partners.

As at December 31, 2005, the West Central Alberta Gas Fairway property consisted of 45,000 gross (27,730 net) acres of developed land and 114,000 gross (87,500 net) acres of undeveloped land.

The Highpine Paddock Report attributes proved plus probable reserves of 5.4 mmboe to Highpine's working interest in the West Central Alberta Gas Fairway area. The Highpine Paddock Report attributes proved reserves of 3.7 mmboe to Highpine's working interest in the West Central Alberta Gas Fairway area.

Highpine commenced activities in this area in January 2002 when Highpine made its first significant exploration discovery with the 4-16-40-27 W4M gas well. This well produced initial rates in excess of 7.0 mmcf/d and to date has recovered approximately 5.0 bcf of natural gas and significant quantities of NGLs. To date, with the Vaquero gas properties included, Highpine has drilled several natural gas discoveries and several oil and natural gas producing wells from secondary targeted zones in the fairway.

In December 2004, Highpine commissioned a 10 mmcf/d, 100% owned and operated natural gas processing facility, located near the middle of Highpine's Joffre acreage. The facility is designed to process natural gas from all of the potential producing horizons in the Joffre area, including low pressure gas and coal bed methane. In addition to processing Highpine's working interest natural gas volumes, Highpine's management believes that this facility will provide third party custom processing and transportation service to a large area in which Highpine and others are currently active.

Highpine's ongoing activity in West Central Alberta Gas Fairway consists of selective exploration and exploitation drilling. In 2006, Highpine's capital budget contemplates that the Corporation will participate in the drilling in excess of 50 gross wells in this area. The average cost, assuming no significant drilling problems, to drill and complete wells in the West Central Alberta Gas Fairway area is approximately $600,000 to $800,000. Costs to tie-in wells is an additional $600,000 to $800,000.

Bantry/Retlaw – Southern Alberta

The Bantry/Retlaw property is located in the Brooks area of Alberta approximately 200 kilometres southeast of Calgary, Alberta. The Bantry/Retlaw property is Highpine's major southern Alberta property producing approximately 576 boe/d and representing approximately 9% of Highpine's total production volumes in 2005. Highpine's interests in Bantry/Retlaw consist of working interests ranging from 1% to 65% and averaging 43% (proved reserves volume weighted). Highpine has an interest in 37 producing wells (13.1 net). The average Highpine working interest production from the property was 485 boe/d for the first week of March 2006. In addition, Highpine has an average 53% working interest in two oil batteries. All of Highpine's production is gathered in flowlines connecting wells to central batteries. At the central batteries, produced oil, natural gas and water are separated. Water is disposed of in water disposal wells, which are operated and/or partially owned by Highpine. Highpine's management believes that the Corporation will have sufficient working interests in water disposal wells in the area to dispose of its share of produced water.

The Bantry/Retlaw property consists of 6,234 gross (1,617 net) acres of developed land and 3,700 gross (1,100 net) acres of undeveloped land.

The Highpine Paddock Report attributes proved plus probable reserves of 1,000 mboe to Highpine's working interest in the Bantry/Retlaw area. The Highpine Paddock Report attributes proved reserves of 850 mboe to Highpine's working interest in the Bantry/Retlaw area.

In May 2000, Highpine acquired a 40% working interest in an oil property at Bantry. This property consists of 18 wells, producing approximately 190 net bbl/d of 25° API oil and miscellaneous associated and non-associated gas volumes. The Bantry property is characterized by long-life oil with ongoing exploitation opportunities, including uphole natural gas re-completions.

Highpine commenced activities in the Retlaw region in March 2002 when it acquired working interests in various oil properties in the area. The properties consisted of several minor working interest producing wells and a 65% working interest in a suspended 29° API Mannville oil pool. The producing properties were subsequently sold at a price equivalent to what was paid for the entire interest acquired in March 2002. In late 2003, after a technical study was completed on the suspended pool, Highpine decided to re-activate the old wells, drill additional wells and install facilities capable of bringing all of the wells on production under high volume lift. These facilities were commissioned in June 2004. Production from the Retlaw area (which is derived from the foregoing oil wells and some uphole natural gas exploitation) is currently averaging approximately 293 boe/d net. Highpine anticipates undertaking further oil optimization and development natural gas drilling on this property in 2006.

Highpine continues to optimize production and reduce the operating costs of certain wells on both properties. Optimization efforts will consist of well stimulations, chemical treatments and the installation of high volume lift and additional water disposal facilities.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The statement of reserves data and other oil and gas information set forth below (the "**Statement**") is dated March 27, 2006. The effective date of the Statement is December 31, 2005 and the preparation date of the Statement is February 3, 2006.

Disclosure of Reserves Data

The reserves data set forth below (the "**Reserves Data**") is based upon an evaluation by Paddock with an effective date of December 31, 2005 contained in the Highpine Paddock Report and an evaluation by Paddock with an effective date of December 31, 2005 contained in the White Fire Paddock Report. The Reserves Data summarizes the oil, NGL and natural gas reserves of the Corporation and the net present values of future net revenue for these reserves using constant prices and costs and forecast prices and costs. Although the Corporation acquired White Fire on February 21, 2006 and therefore did not beneficially own the oil, NGL and natural gas reserves of White Fire until such time, the information is presented as if the White Fire Arrangement had been completed effective December 31, 2005. Information disclosed below under the "Pro Forma Reserves" subheading is shown for convenience of reference, on a pro forma basis effective December 31, 2005. The Reserves Data for Highpine and White Fire conforms to the requirements of NI 51-101. Additional information not required by NI 51-101 has been presented to provide continuity and additional information which Highpine believes is important to the readers of this information. Highpine engaged Paddock to provide an evaluation of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

The tables below summarize Highpine's and White Fire's crude oil, NGL and natural gas reserves and the estimated present worth of future net cash flows associated with such reserves, as at December 31, 2005. The information set forth below is derived from the Highpine Paddock Report and White Fire Paddock Report, which were prepared in accordance with the standards contained in the COGE Handbook and the reserves definitions contained in NI 51-101 and the COGE Handbook. The tables under the "Pro Forma Reserves" subheading summarize and aggregate the data contained in the Highpine Paddock Report and White Fire Paddock Report and, as a result, may contain slightly different numbers than the Highpine Paddock Report and White Fire Paddock Report due to rounding. **All evaluations of future net cash flows are stated before and after the provision for income taxes and prior to indirect costs and after deduction of royalties, estimated future capital expenditures and well abandonment costs and after giving effect to ARTC. It should not be assumed that the present values of estimated future net cash flows shown below is representative of the fair market value of Highpine's crude oil, NGL and natural gas reserves. There is no assurance that the price and cost assumptions used in estimating such future net cash flows will be consistent with actual prices and costs and variances could be material. The recovery and reserve estimates of Highpine's crude oil, NGL and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, NGL and natural gas reserves may be greater than or less than the estimates provided herein.**

The Report of Highpine Management and Directors on Reserves Data and Other Information (on Form 51-101F3) and the Report on Reserves Data by Paddock (on Form 51-101F2) are included in this Annual Information Form. See Schedule B - "Report of Highpine Management and Directors on Oil and Gas Disclosure in Accordance with Form 51-101F3" and Schedule A - "Report on Reserves Data by Paddock Lindstrom & Associates Ltd. in Accordance with Form 51-101F2", respectively.

All of Highpine's reserves are in Canada and, substantially all of such reserves, are in the Province of Alberta.

Highpine Paddock Report

Reserves Data (Constant Prices and Costs)

Summary of Crude Oil, NGL and Natural Gas Reserves and Net Present Values of Estimated Future Net Revenue as of December 31, 2005 Based on Constant Price Assumptions

Reserves Category	Reserves							
	Light and Medium Oil		Heavy Oil		Natural Gas		Natural Gas Liquids	
	Gross (mbbl)	Net (mbbl)	Gross (mbbl)	Net (mbbl)	Gross (mmcf)	Net (mmcf)	Gross (mbbl)	Net (mbbl)
Proved								
Developed Producing	7,233	5,279	618	530	22,674	17,832	1,288	936
Developed Non-Producing	547	395	-	-	8,778	7,134	200	148
Total Developed	7,779	5,674	618	530	31,452	24,966	1,488	1,084
Undeveloped	532	402	-	-	333	263	14	11
Total Proved	8,311	6,076	618	530	31,785	25,229	1,502	1,095
Probable	5,507	3,931	99	85	15,368	12,147	456	336
Total Proved Plus Probable	13,818	10,007	717	615	47,153	37,376	1,958	1,431

Reserves Category	Net Present Values of Future Net Revenue									
	Before Income Taxes Discounted at (%/year)					After Income Taxes Discounted at (%/year)				
	0	5	10	15	20	0	5	10	15	20
	(Thousands of Dollars)									
Proved										
Developed Producing	486,620	416,205	366,753	329,705	300,744	401,483	342,054	301,012	270,589	246,974
Developed Non-Producing	81,288	69,701	61,584	55,548	50,852	53,149	44,819	39,107	34,933	31,730
Total Developed	567,909	485,905	428,337	385,253	351,596	454,632	386,873	340,119	305,522	278,704
Undeveloped	21,139	17,503	14,810	12,750	11,131	13,878	11,348	9,478	8,052	6,935
Total Proved	589,048	503,409	443,147	398,002	362,727	468,511	398,220	349,597	313,574	285,640
Probable	318,157	242,417	195,597	163,685	140,481	212,621	159,943	127,888	106,220	90,540
Total Proved Plus Probable	907,205	745,826	638,744	561,687	503,208	681,132	558,163	477,485	419,794	376,180

Total Future Net Revenue (Undiscounted) as of December 31, 2005 Based on Constant Prices and Costs

Reserves Category	Revenue	Royalties	Operating Costs	Development Costs	Well Abandonment and Reclamation Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Taxes
				(Thousands of Dollars)				
Proved Reserves	985,514	238,659	142,502	13,163	2,143	589,048	120,537	468,511
Proved Plus Probable	1,538,032	381,716	217,010	29,605	2,499	907,204	226,072	681,132

Future Net Revenue by Production Group as of December 31, 2005 Based on Constant Prices and Costs

Reserves Category	Production Group	Future Net Revenue Before Income Taxes (discounted at 10%/year) (Thousands of Dollars)
Proved	Light and Medium Crude Oil (including solution gas and other by–products)	298,693
	Heavy Oil (including solution gas and other by–products)	8,759
	Natural Gas (including by–products but excluding solution gas from oil wells)	132,467
Proved Plus Probable	Light and Medium Crude Oil (including solution gas and other by–products)	452,128
	Heavy Oil (including solution gas and other by–products)	9,820
	Natural Gas (including by–products but excluding solution gas from oil wells)	172,932

Reserves Data (Forecast Prices and Costs)

Summary of Crude Oil, NGL and Natural Gas Reserves and Net Present Values of Estimated Future Net Revenue as of December 31, 2005 Based on Forecast Price Assumptions

	Reserves							
	Light and Medium Oil		Heavy Oil		Natural Gas		Natural Gas Liquids	
Reserves Category	Gross (mbbl)	Net (mbbl)	Gross (mbbl)	Net (mbbl)	Gross (mmcf)	Net (mmcf)	Gross (mbbl)	Net (mbbl)
Proved								
Developed Producing	7,234	5,279	618	530	22,672	17,830	1,287	942
Developed Non-Producing	546	396	-	-	8,760	7,158	200	150
Total Developed	7,780	5,675	618	530	31,432	24,988	1,487	1,092
Undeveloped	532	401	-	-	334	267	14	12
Total Proved	8,312	6,076	618	530	31,766	25,255	1,501	1,104
Probable	5,513	3,937	99	85	15,371	12,180	457	341
Total Proved Plus Probable	13,825	10,013	717	615	47,137	37,435	1,958	1,445

	Net Present Values of Future Net Revenue									
	Before Income Taxes Discounted at (%/year)					After Income Taxes Discounted at (%/year)				
Reserves Category	0	5	10	15	20	0	5	10	15	20
	(Thousands of Dollars)									
Proved										
Developed Producing	439,230	382,537	342,028	311,167	286,668	368,429	318,846	284,051	257,883	237,308
Developed Non-Producing	72,123	63,261	56,901	52,066	48,228	47,255	40,616	36,006	32,593	29,940
Total Developed	511,354	445,798	398,929	363,233	334,896	415,684	359,462	320,057	290,476	267,248
Undeveloped	18,126	15,215	13,022	11,319	9,964	11,868	9,821	8,286	7,098	6,157
Total Proved	529,480	461,013	411,951	374,552	344,860	427,552	369,284	328,343	297,574	273,405
Probable	269,397	207,821	169,706	143,569	124,406	181,064	137,237	110,781	92,878	79,854
Total Proved Plus Probable	798,877	668,833	581,657	518,121	469,266	608,616	506,520	439,124	390,452	353,260

Total Future Net Revenue (Undiscounted)
as of December 31, 2005 Based on
Forecast Prices and Costs

Reserves Category	Revenue	Royalties	Operating Costs	Development Costs	Well Abandonment and Reclamation Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Taxes
				(Thousands of Dollars)				
Proved Reserves	927,301	225,145	156,737	13,293	2,646	529,480	101,928	427,552
Proved Plus Probable	1,431,775	354,901	244,910	29,797	3,289	798,877	190,261	608,616

Future Net Revenue by Production Group
as of December 31, 2005 Based on
Forecast Prices and Costs

Reserves Category	Production Group	Future Net Revenue Before Income Taxes (discounted at 10%/year) (Thousands of Dollars)
Proved	Light and Medium Crude Oil (including solution gas and other by–products)	280,151
	Heavy Oil (including solution gas and other by–products)	11,212
	Natural Gas (including by–products but excluding solution gas from oil wells)	117,463
Proved Plus Probable	Light and Medium Crude Oil (including solution gas and other by–products)	415,370
	Heavy Oil (including solution gas and other by–products)	12,449
	Natural Gas (including by–products but excluding solution gas from oil wells)	150,028

Pro Forma Reserves

Reserves Data (Forecast Prices and Costs)

Summary of Crude Oil, NGL and Natural Gas Reserves and Net Present Values of Estimated Future Net Revenue as of December 31, 2005 Based on Forecast Price Assumptions

	Reserves							
	Light and Medium Oil		Heavy Oil		Natural Gas		Natural Gas Liquids	
Reserves Category	Gross (mbbl)	Net (mbbl)	Gross (mbbl)	Net (mbbl)	Gross (mmcf)	Net (mmcf)	Gross (mbbl)	Net (mbbl)
Proved								
Developed Producing	7,388	5,410	618	530	26,718	20,775	1,489	1,076
Developed Non-Producing	633	467	-	-	11,566	9,290	445	328
Total Developed	8,021	5,877	618	530	38,284	30,065	1,934	1,404
Undeveloped	532	402	-	-	333	267	14	11
Total Proved	8,553	6,279	618	530	38,617	30,332	1,948	1,415
Probable	5,646	4,045	99	85	19,448	15,135	711	513
Total Proved Plus Probable	14,199	10,324	717	615	58,065	45,467	2,659	1,928

	Net Present Values of Future Net Revenue				
	Before Income Taxes Discounted at (%/year)				
Reserves Category	0	5	10	15	20
	(Thousands of Dollars)				
Proved					
Developed Producing	469,119	407,095	363,286	330,126	303,912
Developed Non-Producing	98,502	85,621	76,955	70,493	65,388
Total Developed	567,622	492,716	440,242	400,620	369,299

Reserves Category	Net Present Values of Future Net Revenue Before Income Taxes Discounted at (%/year) 0	5	10	15	20
	(Thousands of Dollars)				
Undeveloped	18,108	15,201	13,011	11,313	9,960
Total Proved	585,729	507,917	453,253	411,933	379,259
Probable	295,850	225,500	182,809	153,799	132,650
Total Proved Plus Probable	881,580	733,417	636,062	565,732	511,909

Notes:

(1) Columns may not add due to rounding.

(2) "**Gross**" means Highpine's total working interest and/or royalty interest share before royalties owned by others.

"**Net**" means Highpine's total working interest and/or royalty interest share after deducting the amounts attributable to royalties owned by others.

"**Royalties**" refers to royalties paid to others. The royalties deducted from the reserves are based on the percentage royalty calculated by applying the applicable royalty rate or formula. In the case of Crown sliding scale royalties, which are dependent on selling prices, the price forecasts for the individual properties in question have been employed.

"**Reserves**" are the estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on: analysis of drilling, geological, geophysical and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable. Reserves are classified according to the degree of certainty associated with the estimates.

"**Proved Reserves**" are those Reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated Proved Reserves. At least a 90% probability that the quantities actually recovered will equal or exceed the estimated Proved Reserves is the targeted level of certainty.

"**Probable Reserves**" are those additional Reserves that are less certain to be recovered than Proved Reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated Proved plus Probable Reserves. At least a 50% probability that the quantities actually recovered will equal or exceed the sum of the estimated Proved plus Probable Reserves is the targeted level of certainty.

"**Proved Developed Reserves**" are those Reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (e.g., when compared to the cost of drilling a well) to put the Reserves on production. The developed category may be subdivided into producing and non-producing.

"**Developed Producing Reserves**" are those Reserves that are expected to be recovered from completion intervals open at the time of the estimate. These Reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

"**Developed Non-Producing Reserves**" are those Reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

"**Undeveloped Reserves**" are those Reserves expected to be recovered from known accumulations where a significant expenditure (e.g., when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the Reserves classification (proved, probable, possible) to which they are assigned.

(3) The forecast cost and price assumptions assume the continuance of current laws and regulations and increases in wellhead selling prices, and take into account inflation with respect to future operating capital costs. In the Highpine Paddock Report, operating costs are assumed to escalate at 2% per annum. Crude oil and natural gas base case prices as forecast by Paddock effective December 31, 2005 are as follows:

Summary of Pricing and Inflation Rate Assumptions as at December 31, 2005
Forecast Prices and Costs

	Oil				Natural Gas	Edmonton Liquids Prices				
Year	WTI Cushing Oklahoma ($US/bbl)	Edmonton Par Price 40° API ($Cdn/bbl)	Hardisty Heavy 25° API ($Cdn/bbl)	Cromer Medium 29.3° API ($Cdn/bbl)	AECO Gas Price ($Cdn/mmbtu)	Propane ($Cdn/bbl)	Butane ($Cdn/bbl)	Pentanes Plus ($Cdn/bbl)	Inflation Rates [(a)] %/Year	Exchange Rate[(b)] ($US/$Cdn)
Forecast										
2006	60.00	69.57	46.57	64.70	10.54	41.74	48.70	69.57	2.0	0.850
2007	57.50	66.61	47.61	61.94	9.52	39.96	46.62	66.61	2.0	0.850
2008	55.00	63.64	50.64	59.19	8.32	38.19	44.55	63.64	2.0	0.850
2009	52.50	60.68	47.68	56.43	7.71	36.41	42.48	60.68	2.0	0.850
2010	50.00	57.72	44.46	53.68	7.10	34.63	40.40	57.72	2.0	0.850
2011	47.50	54.76	41.23	50.92	7.24	32.85	38.33	54.76	2.0	0.850
2012	48.45	55.85	42.06	51.94	7.39	33.51	39.10	55.85	2.0	0.850
2013	49.42	56.97	42.90	52.98	7.53	34.18	39.88	56.97	2.0	0.850
2014	50.41	58.11	43.75	54.04	7.68	34.86	40.68	58.11	2.0	0.850
2015	51.42	59.27	44.63	55.12	7.84	35.56	41.49	59.27	2.0	0.850
Thereafter					+ 2%/year					

Notes:

(a) Inflation rates for forecasting prices and costs.

(b) Exchange rates used to generate the benchmark reference prices in this table.

(4) Weighted average historical prices realized by Highpine for the year ended December 31, 2005 were $9.71/mcf for natural gas, $68.33/bbl for oil and $62.30/bbl for NGLs.

(5) The constant price assumptions assume the continuance of current laws, regulations and operating costs in effect on the date of the Highpine Paddock Report. Product prices were not escalated beyond December 31, 2005. In addition, operating and capital costs have not been increased on an inflationary basis. The prices used for the mix of crude oil gravities and various gas contracts were as follows (adjusted for quality and transportation).

Summary of Pricing Assumptions as of December 31, 2005
Constant Prices and Costs

	Oil				Natural Gas	Edmonton Liquid Prices			
Year	WTI Cushing Oklahoma ($US/bbl)	Edmonton Par Price 40° API ($Cdn/bbl)	Hardisty Heavy 25° API ($Cdn/bbl)	Cromer Medium 29.3° API ($Cdn/bbl)	AECO Gas Price ($Cdn/Mmbtu)	Propane ($Cdn/bbl)	Butane ($Cdn/bbl)	Pentanes Plus ($Cdn/bbl)	Exchange Rate ($US/$Cdn)
2005	61.06	68.05	37.34	60.06	9.50	44.34	54.03	71.03	0.8598

(6) The extent and character of all factual data supplied to Paddock was accepted by Paddock as represented. The crude oil and natural gas reserve calculations and any projections upon which the Highpine Paddock Report are based were determined in accordance with generally accepted evaluation practices. No field inspections were conducted. Salvage values for facilities and base reclamation costs for any of the Corporation's wells which were assigned no reserves have not been included in the Highpine Paddock Report. No costs were included in the Highpine Paddock Report for the abandonment of surface facilities or gathering systems or for the reclamation of surface leases.

(7) ARTC is included in the cumulative cash flow amounts. ARTC is based on the program announced November 1989 by the Alberta government with modifications effective January 1, 1995. The Corporation will qualify for the maximum ARTC.

(8) Estimated future abandonment and reclamation costs related to a property have been taken into account by Paddock in determining reserves that should be attributed to a property, and, in determining the aggregate future net revenue therefrom, Paddock deducted the reasonable estimated future well abandonment costs.

Reconciliations of Changes in Reserves and Future Net Revenue

Reconciliation of Company Net Reserves by Principal Product Type Based on Constant Prices and Costs

Factors	Light and Medium Oil			Heavy Oil			Associated and Non-Associated Gas			Natural Gas Liquids		
	Net Proved (mbbl)	Net Probable (mbbl)	Net Proved Plus Probable (mbbl)	Net Proved (mbbl)	Net Probable (mbbl)	Net Proved Plus Probable (mbbl)	Net Proved (mmcf)	Net Probable (mmcf)	Net Proved Plus Probable (mmcf)	Net Proved (mbbl)	Net Probable (mbbl)	Net Proved Plus Probable (mbbl)
December 31, 2004	2,620	1,682	4,302	662	131	793	14,345	6,284	20,629	687	222	909
Extensions	-	988	988	-	-	-	-	923	923	-	34	34
Improved Recovery	-	-	-	-	-	-		-	-	-	-	-
Technical Revisions	1,240	(719)	521	3	(39)	(36)	(1,665)	(3,920)	(5,585)	266	(102)	164
Discoveries	127	626	753	-	-	-	7,008	4,609	11,617	96	79	175
Acquisitions	2,831	1,355	4,186	-	-	-	9,072	4,251	13,323	274	103	377
Dispositions	-	-	-	(35)	(7)	(42)	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-	-	-	-	-	-	-
Production	(743)	-	(743)	(100)	-	(100)	(3,531)	-	(3,531)	(228)	-	(228)
December 31, 2005	6,075	3,932	10,007	530	85	615	25,229	12,147	37,376	1,095	336	1,431

Reconciliation of Changes in Net Present Values of Future Net Revenue Discounted at 10% Per Year Proved Reserves Constant Prices and Costs

Period and Factor	After Tax 2005
	(Thousands of Dollars)
Estimated Future Net Revenue at December 31, 2004	97,405
Sales and Transfers of Oil and Gas Produced, Net of Production Costs and Royalties (1)	(91,294)
Net Change in Prices, Production Costs and Royalties Related to Future Production	70,500
Changes in Previously Estimated Development Costs Incurred During the Period	(1,286)
Changes in Estimated Future Development Costs	(11,820)
Extensions and Improved Recovery	-
Discoveries	47,019
Acquisitions of Reserves	178,835
Dispositions of Reserves	(592)
Net Change Resulting from Revisions in Quantity Estimates	32,446
Accretion of Discount (2)	9,741
Net Change in Income Taxes (3)	(64,228)
All Other Changes	82,871
Estimated Future Net Revenue at December 31, 2005	349,597

Notes:

(1) Cash flow from operations.

(2) Estimated as 10% of the beginning of period net present value.

(3) The difference between income taxes at beginning of period and income taxes at end of period.

Future Development Costs

The following table sets forth development costs deducted by Paddock in the estimation of the future net revenue for Highpine's properties and assets attributable to the reserve categories noted below.

Year	Forecast Prices and Costs: Proved Reserves	Forecast Prices and Costs: Proved Plus Probable Reserves	Constant Prices and Costs: Proved Reserves	Constant Prices and Costs: Proved Plus Probable Reserves
	(Thousands of Dollars)			
2006	8,682	21,827	8,682	21,827
2007	2,556	6,447	2,505	6,320
2008	2,055	1,353	1,975	1,300
2009	-	-	-	-
2010	-	171	-	158
Total: Undiscounted	13,293	29,797	13,163	29,605
Total: Discounted at 10%/year	12,112	27,576	12,006	27,417

In all years for which economic forecasts were made by Paddock in the Highpine Paddock Report, the net revenues from the reserves attributable to Highpine's properties and assets are well in excess of the estimated future development costs. Therefore, the Highpine Paddock Report assumes that the Corporation will be able to fund the anticipated expenditures for future development entirely out of its cash flow and will not require other sources in order to develop the proved or probable reserves. As a result, interest or other costs of external funding are not included in the reserves and future net revenue estimates.

Additional Information Relating to Reserves Data

Undeveloped Reserves

The following tables set forth the proved undeveloped reserves and the probable undeveloped reserves, each by product type, attributed to the Corporation as at the end of each of the financial years noted.

Proved Undeveloped Reserves

Year	Light and Medium Oil	Heavy Oil	Natural Gas	Natural Gas Liquids	BOE
	(mbbls)	(mbbls)	(mmcf)	(mbbls)	(mboe)
2003	216	-	156	9	251
2004	830	-	649	38	976
2005	532	-	333	14	602

In 2005, proved undeveloped reserves were attributed to the Pembina/Nisku GG and HH properties for two drilling locations. As of the date of this Annual Information Form, both wells are expected to be drilled in the next two years.

Probable Undeveloped Reserves

Year	Light and Medium Oil	Heavy Oil	Natural Gas	Natural Gas Liquids	BOE
	(mbbls)	(mbbls)	(mmcf)	(mbbls)	(mboe)
2003	97	-	1,423	15	349
2004	1,073	-	3,968	62	1,796
2005	3,104	-	7,399	161	4,498

In 2005, the majority of the probable undeveloped reserves were related to four drilling locations in the Pembina HH, VV and WW Nisku pools. As of the date of this Annual Information Form, all wells are expected to be drilled in the next two years.

Undeveloped Reserves

In general, once proved and/or probable undeveloped reserves are identified they are integrated into Highpine's development plans. The Corporation's business plan generally envisions the development of proved and probable undeveloped reserves within two years of the date of such integration. The various factors that could result in delayed or cancelled development include:

- changing economic conditions;
- changing technical conditions (production anomalies (i.e., water breakthrough, accelerated depletion));
- multi-zone developments (i.e. a prospective formation completion may be delayed until the initial completion is no longer economic);
- a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and
- surface access issues (landowners, weather conditions and regulatory approvals, for example).

Significant Factors or Uncertainties

Other than the various risks and uncertainties that participants in the oil and gas industry are exposed to generally, Highpine is unable to identify any important economic factors or significant uncertainties that will affect any particular components of the reserves data disclosed herein. See "Risk Factors".

Landholdings

Highpine's developed and undeveloped landholdings (in acres) as at December 31, 2005, are set forth in the following table.

	Undeveloped		Developed		Total	
	Gross (1)	Net (2)	Gross (1)	Net (2)	Gross (1)	Net (2)
Alberta	305,285	209,672	89,400	38,794	394,685	248,466
Saskatchewan	640	320	0	0	640	320
Total	305,925	209,992	89,400	38,794	395,325	248,786

Notes:

(1) "**Gross**" means, collectively, the total number of acres in which Highpine, Pino Alto, HAC, Highpine Energy and Highpine Partnership have an interest.

(2) "**Net**" means, collectively, the aggregate of the percentage working interests of Highpine, Pino Alto, HAC, Highpine Energy and Highpine Partnership in the Gross acres.

The Corporation expects that rights to explore, develop and exploit 60,300 gross (29,600 net) acres of undeveloped landholdings attributable to Highpine's properties and assets may expire by December 31, 2006.

Other Oil and Gas Information

Oil and Natural Gas Wells

The following table summarizes Highpine's interest, as at December 31, 2005, in producing wells and wells that Highpine considers to be capable of production.

	Producing Wells				Shut-in Wells (3)			
	Oil		Natural Gas		Oil		Natural Gas	
	Gross (1)	Net (2)	Gross (1)	Net (2)	Gross (1)	Net (2)	Gross (1)	Net (2)
Alberta	128	29.1	975	37.6	6	2.8	24	9.4
Saskatchewan	5	0.1	-	-	-	-	-	-

Notes:

(1) "**Gross**" refers to all wells in which Highpine has either a working interest or a royalty interest.

(2) "**Net**" refers to the aggregate of the percentage working interests of Highpine in the gross wells, before the deduction of royalties.

(3) "**Shut-in Wells**" refers to wells that are capable of producing crude oil or natural gas, but which are not producing due to lack of available transportation facilities, available markets or other reasons. Shut-in wells in which Highpine has an interest are located no further than 10 kilometres from existing pipelines.

Capital Expenditures

The following table sets out Highpine's capital expenditures for various categories of expenditure, for the periods indicated.

	Years Ended December 31,		
	2005	2004	2003
	(Thousands of Dollars)		
Land and seismic	56,700	17,465	11,644
Drilling and completions	54,200	26,897	8,793
Facilities and equipment	36,400	21,633	2,843
Property acquisitions and dispositions (net)	3,800	(4,973)	194
Corporate acquisition (1)	257,300	51,151	-
Other	2,500	111	32
Total	410,900	112,284	23,506

Note:

(1) Corporate acquisition only includes the amount allocated to property, plant and equipment.

Drilling Activity

The following table summarizes Highpine's drilling results for the periods indicated.

	Year Ended December 31, 2005		Year Ended December 31, 2004		Year Ended December 31, 2003	
	Gross (1)	Net (2)	Gross (1)	Net (2)	Gross (1)	Net (2)
Crude oil	9	6.5	13	6.6	5	1.6
Natural gas	19	11.0	25	10.0	10	6.1
Service	11	4.4	7	2.7	-	-
Dry and abandoned	17	14.5	9	3.4	9	6.6
Total	56	36.4	54	22.7	24	14.3

Notes:

(1) "**Gross**" wells refers to all wells in which Highpine has either a working interest or a royalty interest.

(2) "**Net**" wells refers to the aggregate of the percentage working interests of Highpine in the gross wells, before the deduction of royalties.

History – Daily Sales Volumes and Netbacks

The following tables set forth Highpine's daily sales volumes and netbacks on a quarterly basis for the periods indicated.

	2005				
	Year Ended December 31	**Fourth Quarter**	**Third Quarter**	**Second Quarter**	**First Quarter**
	(unaudited)	(unaudited)	(unaudited)	(unaudited)	(unaudited)
Production					
Crude oil and NGL (bbls/d)	3,984	5,881	5,562	2,617	1,816
Natural gas (mcf/d)	13,823	16,006	18,277	11,593	9,293
Oil equivalent (boe/d)	6,288	8,549	8,608	4,549	3,365
Netbacks per boe					
Revenue (1)	61.30	67.74	65.12	52.56	46.54
Royalties	(16.99)	(20.79)	(16.40)	(14.11)	(12.60)
Production expenses (2)	(7.41)	(7.34)	(7.17)	(9.52)	(5.34)
Netback	36.90	39.61	41.55	28.93	28.60
Netbacks per bbl – Oil and NGL					
Revenue (1)	63.06	65.17	68.23	57.04	48.65
Royalties	(17.46)	(19.73)	(16.06)	(16.02)	(15.80)
Production expenses (2)	(7.35)	(7.14)	(6.16)	(10.68)	(5.83)
Netback	38.25	38.30	46.01	30.34	27.02
Netbacks per mcf – Natural Gas					
Revenue (1)	9.71	12.23	9.87	7.80	7.34
Royalties	(2.70)	(3.86)	(2.84)	(1.92)	(1.48)
Production expenses (2)	(1.26)	(1.23)	(1.50)	(1.33)	(0.79)
Netback	5.75	7.14	5.53	4.55	5.07
Capital Expenditures					
Land and seismic	56,700	16,700	23,400	500	16,100
Drilling and completion	54,200	18,900	18,000	8,000	9,300
Facilities and equipment	36,400	8,600	7,300	11,200	9,300
Property acquisitions and dispositions (net)	3,800	4,300	(500)	-	-
Corporate acquisition (3)	257,300	-	-	257,300	-
Other	2,500	2,400	-	-	100
Total	410,900	50,900	48,200	277,000	34,800

	2004					2003
	Year Ended December 31	**Fourth Quarter**	**Third Quarter**	**Second Quarter**	**First Quarter**	**Fourth Quarter**
	(unaudited)	(unaudited)	(unaudited)	(unaudited)	(unaudited)	(unaudited)
Production						
Crude oil and NGL (bbls/d)	1,578	1,897	1,812	1,628	969	514
Natural gas (mcf/d)	6,423	6,784	7,091	6,759	5,046	4,281
Oil equivalent (boe/d)	2,648	3,027	2,994	2,754	1,810	1,227
Netbacks per boe						
Revenue (1)	42.33	42.87	41.78	45.10	38.10	38.35
Royalties	(10.46)	(9.60)	(12.24)	(10.99)	(8.14)	(6.88)
Production expenses (2)	(6.12)	(4.78)	(5.59)	(8.14)	(6.21)	(8.79)
Netback	25.75	28.49	23.95	25.97	23.75	22.68

	2004					2003
	Year Ended December 31	Fourth Quarter	Third Quarter	Second Quarter	First Quarter	Fourth Quarter
	(unaudited)	(unaudited)	(unaudited)	(unaudited)	(unaudited)	(unaudited)
Netbacks per bbl – Oil and NGL						
Revenue (1)	42.91	42.47	43.92	45.48	37.52	32.55
Royalties	(12.89)	(10.10)	(12.43)	(12.02)	(8.26)	(7.18)
Production expenses (2)	(6.96)	(5.32)	(6.41)	(9.74)	(7.00)	(12.92)
Netback	23.06	27.05	25.08	23.72	22.26	12.45
Netbacks per mcf – Natural Gas						
Revenue (1)	6.91	7.25	6.41	7.42	6.46	7.09
Royalties	(1.61)	(1.46)	(1.99)	(1.58)	(1.33)	(1.12)
Production expenses (2)	(0.81)	(0.65)	(0.72)	(0.97)	(0.88)	(0.98)
Netback	4.49	5.14	3.70	4.87	4.25	4.99
Capital Expenditures						
Land and seismic	17,465	10,329	2,530	3,513	1,093	5,308
Drilling and completion	26,897	3,158	9,027	10,047	4,665	978
Facilities and equipment	21,633	10,506	4,271	4,328	2,528	317
Property acquisitions and dispositions (net)	(4,973)	(408)	(3,395)	(1,170)	-	16
Corporate acquisition (3)	51,151	-	-	-	51,151	-
Other	111	34	69	7	1	12
Total	112,284	23,619	12,502	16,725	59,438	6,631

Notes:

(1) After giving effect to realized commodity hedges.

(2) Production expenses include expenses related to transportation, well workovers, fuel and power costs related to operation of wells, operator wages and salaries and other miscellaneous production costs and are reduced by processing revenues.

(3) Corporate acquisition only includes the amount allocated to property, plant and equipment.

Forward Contracts

At March 27, 2006, Highpine had the following financial commodity contracts for the remainder of 2006:

Oil collar	2,000 bbls/d	U.S.$60.00 – $69.80/bbl
Oil collar	1,000 bbls/d	U.S.$55.00 – $77.25/bbl
Gas collar	5,000 GJs/d	Cdn.$9.00 – $14.70/GJ

Additional Information Concerning Abandonment and Reclamation Costs

The following table discloses the expected abandonment and reclamation costs of the proven and probable Highpine assets as at December 31, 2005, calculated both undiscounted and at a 10 percent discount rate with a portion thereof anticipated to be paid in each of the next three years.

	Abandonment and Reclamation Costs	Abandonment and Reclamation Costs in Disclosed Reserves Data
	(Thousands of Dollars)	
Total as at December 31, 2005	12,272	3,289
Total as at December 31, 2005 – Discounted 10%	4,903	1,050
Anticipated to be paid in 2006 – Undiscounted	125	26
Anticipated to be paid in 2007 – Undiscounted	125	59
Anticipated to be paid in 2008 – Undiscounted	125	61

Highpine estimates the costs to abandon and reclaim all its shut in and producing wells, facilities, gas plants, pipelines, batteries and satellites. Estimated expenditures for each operating area are based on the AEUB methodology, which details the cost of abandonment and reclamation in each specific geographic region. Facility reclamation costs are scheduled to be incurred in the year following the end of the reserve life of its associated reserves. The Corporation will be liable for its share of ongoing environmental obligations and for the ultimate reclamation of the properties held by it upon abandonment. Ongoing environmental obligations are expected to be funded out of cash flow. The Corporation currently estimates that the future environmental and reclamation obligations net of salvage value in respect of Highpine's properties and assets will aggregate approximately $12.3 million escalated at 2% per year.

As at December 31, 2005, Highpine expected to incur reclamation and abandonment costs in respect of 320 gross (100.9 net) wells located on its properties and assets.

Tax Horizon

Highpine's management does not expect that Highpine will be taxable in the next one to two years. Highpine has estimated approximately $305 million of tax pools will be available as at December 31, 2005, which can be used to off-set taxable income in future years.

Costs Incurred

The following table summarizes certain costs (irrespective of whether such costs were capitalized or recorded as an expense) incurred by Highpine for the periods indicated.

Expenditures	Year Ended December 31, 2005	Year Ended December 31, 2004
	(Thousands of Dollars)	
Property acquisition costs – Unproved properties [1]	135,400 [3]	17,500
Property acquisition costs – Proved properties	182,400	46,200
Exploration drilling and completions	36,400	13,550
Development costs [2]	54,200	34,923
Other	2,500	111
Total	410,900	112,284

Notes:

(1) Cost of land acquired and geological and geophysical capital expenditures.

(2) Development drilling and facility and equipping.

(3) Property acquisition costs – Unproved properties includes $78,700 allocated to unproved properties as part of the Vaquero Arrangement.

Exploration and Development Activities

The following table sets out the number of exploratory and development wells (both on a gross and net basis) in which Highpine participated during the periods indicated.

	Year Ended December 31, 2005			
	Exploratory Wells		Development Wells	
	Gross [1]	Net [2]	Gross [1]	Net [2]
Oil	8	6.4	1	0.1
Natural Gas	12	9.0	7	2.0
Service	10	4.0	1	0.4
Dry	13	11.7	4	2.8
Total:	43	31.1	13	5.3

	Year Ended December 31, 2004			
	Exploratory Wells		Development Wells	
	Gross [1]	Net [2]	Gross [1]	Net [2]
Oil	6	1.4	7	5.2
Natural Gas	2	1.1	23	8.9
Service	1	0.3	6	2.4
Dry	4	1.6	5	1.8
Total:	13	4.4	41	18.3

Notes:

(1) "**Gross**" means the total number of wells in which the Corporation has an interest.

(2) "**Net**" means the number of wells obtained by aggregating the working interest to be acquired by the Corporation in each of its gross wells.

For details concerning anticipated 2006 exploration and development activities in respect of Highpine's properties and assets, see "Description of Principal Properties".

Production Estimates

The following table sets out the volumes of the proved plus probable gross production estimated for the year ending December 31, 2006 as estimated by Paddock in assessing the future net revenue disclosed in the tables above.

	Light and Medium Oil (bbls/d)	Heavy Oil (bbls/d)	Natural Gas (mcf/d)	Natural Gas Liquids (bbls/d)	BOE (boe/d)
2006 Pembina [1]	6,239	-	7,993	766	8,337
2006 West Central Alberta Gas Fairway [1]	219	-	12,635	200	2,525
Total 2006	7,346	163	22,157	1,004	12,206

Note:

(1) Pembina and West Central Alberta Gas Fairway account for more than 89% of the estimated production attributable to Highpine's properties and assets.

Production History

The following tables summarize certain information respecting the production, product prices received, royalties paid, operating expenses and resulting netback for Highpine for the periods indicated.

		Average per Unit of Volume Production ($/bbl, $/mcf)			
Product Type/2005 Quarter	Average Daily Production Volume [1]	Price Received	Royalties Paid	Production Costs	Resulting Netback [2]
Light and Medium Oil and NGLs					
First Quarter	1,640	49.70	16.78	5.66	27.26
Second Quarter	2,436	58.13	16.65	10.86	30.62
Third Quarter	5,389	68.60	16.25	6.07	46.28
Fourth Quarter	5,713	65.78	20.08	7.06	38.64

Product Type/2005 Quarter	Average Daily Production Volume (1)	Average per Unit of Volume Production ($/bbl, $/mcf) Price Received	Royalties Paid	Production Costs	Resulting Netback (2)
Heavy Oil					
First Quarter	176	38.91	6.73	7.46	24.72
Second Quarter	181	42.45	7.51	8.34	26.60
Third Quarter	173	56.74	9.90	9.02	37.82
Fourth Quarter	168	44.38	7.79	9.82	26.77
Natural Gas					
First Quarter	9,293	7.34	1.48	0.79	5.07
Second Quarter	11,593	7.80	1.92	1.33	4.55
Third Quarter	18,277	9.87	2.84	1.50	5.53
Fourth Quarter	16,006	12.23	3.86	1.23	7.14

Notes:

(1) Before deduction of royalties.

(2) Netbacks are calculated by subtracting royalties, operating expenses and transportation expenses from revenues.

The following table summarizes certain production information for each of Highpine's important fields for the year ended December 31, 2005.

	Light and Medium Oil (mbbls)	Heavy Oil (mbls)	Natural Gas (mmcf)	Natural Gas Liquids (mbbls)
Bantry/Retlaw	83	64	343	6
West Central Alberta Gas Fairway	26	-	2,779	56
Pembina	984	-	1,506	198
Other	29	-	417	8
Total	1,122	64	5,045	268

Incremental Exploitation and Development Potential

Management of the Corporation has identified several opportunities to increase existing production in Highpine's properties and assets, which are in addition to the future development projects taken into consideration by Paddock in estimating the Reserve Values contained in the Highpine Paddock Report. Opportunities being considered include:

- approximately 84 exploration and development drilling locations at Pembina, Joffre and Sturgeon Lake;
- well re-completions to convert wells that have been producing in various zones evaluated in the Highpine Paddock Report to produce from zones to which Paddock did not assign reserves;
- additional drilling locations that have been identified through a review of 2-D and 3-D seismic data;
- drilling of additional water injection wells and the addition of free-water knockouts to increase water disposal capacity at Bantry and Retlaw, which may allow for further increases in oil production beyond those evaluated in the Highpine Paddock Report; and
- increased production rates from the granting of GPP (unrestricted well flow notes) and incremental increases of oil reserves from higher reservoir recovery factors.

Neither the capital costs nor the potential incremental production associated with these opportunities are reflected in the Highpine Paddock Report.

The Corporation may also identify further development projects and other opportunities to optimize production from its properties and implement operational efficiencies to lower operating expenses from those forecasted in the Highpine Paddock Report, as it enhances its understanding of its properties and assets with the benefit of new information generated from ongoing operations.

Production History

The following table summarizes the sales volumes of crude oil and natural gas attributable to Highpine's properties and assets, before deduction of royalties, for the periods indicated. Average production for the year ended December 31, 2005 was 6,288 boe/d.

	Years Ended December 31,		
	2005	2004	2003
Crude oil and natural gas liquids (mbbls)	1,454	576	162
Average daily production (bbls/d)	3,984	1,578	443
Natural gas sales (mmcf)	5,045	2,344	1,563
Average daily sales (mcf/d)	13,823	6,423	4,281
Total oil equivalent (mboe)	2,295	967	422
Average daily production (boe/d)	6,288	2,648	1,157

Direct Revenue and Operating Expenses

The following table summarizes the revenue and operating expenses directly attributable to Highpine's properties and assets for the periods indicated.

	Years Ended December 31,		
	2005	2004	2003
		(Thousands of Dollars)	
Revenue:			
Petroleum and natural gas sales before hedging (1)	147,303	43,743	16,596
Royalties	(38,995)	(10,140)	(3,108)
Operating expenses net of processing revenues (2)	(17,014)	(5,935)	(1,963)
Operating Income	91,294	27,668	11,525

Notes:

(1) Average product prices received for the years ended December 31, 2005, 2004 and 2003 were $64.18/boe, $45.13/boe and $39.31/boe, respectively.

(2) Operating expenses include transportation costs.

Marketing Arrangements

Highpine Crude Oil Summary

Crude oil produced by Highpine is currently marketed via Plains Marketing L.P. on 30 day Evergreen contracts, which are renegotiated on an annual basis.

A summary of financial commodity contracts is presented under "Forward Contracts" above.

Highpine Natural Gas and Natural Gas Liquids Summary

Highpine markets the majority of its natural gas production on both the ATCO and TransCanada Corporation pipeline systems, to various creditworthy counterparties at the Canadian Gas Price Reporter 4A Daily Index under 30 day rolling arrangements.

Highpine holds two minor system gas contracts with Pan-Alberta Gas Ltd. and Cargill Ltd. which are for the Economic Life of reserves.

Highpine did not enter into any physical hedging arrangements in 2005. On closing of the Vaquero Arrangement, Highpine assumed a 3,000 GJ/d physical gas sale contract with BP Canada for the period April 1, 2005 to October 31, 2005.

Highpine's natural gas liquids are sold for the April 1-March 31 contract year to various counterparties which are all now under price renegotiation for the 2007-2008 period.

INDUSTRY CONDITIONS

The oil and natural gas industry is subject to extensive controls and regulations governing its operations (including land tenure, exploration, development, production, refining, transportation and marketing) imposed by legislation enacted by various levels of government and, with respect to pricing and taxation of oil and natural gas, by agreements among the governments of Canada, Alberta, British Columbia and Saskatchewan, all of which should be carefully considered by investors in the oil and gas industry. It is not expected that any of these controls or regulations will affect Highpine's operations in a manner materially different than they would affect other oil and gas companies of similar size. All current legislation is a matter of public record and Highpine is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry.

Pricing and Marketing – Oil and Natural Gas

The price of oil is determined by negotiation between buyers and sellers. Such price depends in part on oil quality, prices of competing oils, distance to market, the value of refined products and the supply/demand balance. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada (the "**NEB**"). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export license from the NEB and the issuance of such license requires the approval of the Governor in Council.

The price of natural gas is determined by negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m^3/day) must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or a larger quantity requires an exporter to obtain an export license from the NEB and the issuance of such license requires the approval of the Governor in Council.

The governments of Alberta, British Columbia and Saskatchewan also regulate the volume of natural gas that may be removed from those provinces for consumption elsewhere based on such factors as reserve ability, transportation arrangements and market considerations.

The North American Free Trade Agreement

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, United States of America and Mexico became effective on January 1, 1994. NAFTA carries forward most of the material energy terms that are contained in the Canada – United States Free Trade Agreement. Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to domestic use (based upon the proportion prevailing in the most recent 36 month period); (ii) impose an export price higher than the domestic price; or (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum export or import price requirements.

NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes. The agreement also contemplates clearer disciplines on regulators to ensure fair implementation of any regulatory changes and to minimize disruption of contractual arrangements, which is important for Canadian natural gas exports.

Provincial Royalties and Incentives

In addition to federal regulation, each province has legislation and regulations that govern land tenure, royalties, production rates, environmental protection and other matters. The royalty regime is a significant factor in the profitability of crude oil, natural gas liquids, sulphur and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date and the type or quality of the petroleum product produced.

From time to time the governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays and tax credits, and are generally introduced when commodity prices are low. The programs are designed to encourage exploration and development activity by improving earnings and cash flow within the industry.

Regulations made pursuant to the *Mines and Minerals Act* (Alberta) provide various incentives for exploring and developing oil reserves in Alberta. Oil produced from horizontal extensions commenced at least five years after the well was originally spudded may also qualify for a royalty reduction. An 8,000 m^3 royalty exemption is available to production from a reactivated well that has not produced for the preceding 24-month period, if reactivation occurred after February 1, 1993. As well, oil production from eligible new field and new pool wildcat wells and deeper pool test wells spudded or deepened after September 30, 1992 is entitled to a 12-month royalty exemption (to a maximum of $1 million). Oil produced from low productivity wells, enhanced recovery schemes (such as injection wells) and experimental projects is also subject to royalty reductions.

The Alberta government has also introduced a Third Tier oil royalty with a base rate of 10% and a rate cap of 25% for oil pools discovered after September 30, 1992. The new oil royalty reserved to the Crown has a base rate of 10% and a rate cap of 30% for oil pools discovered between April 1, 1974 and September 1, 1992. The old oil royalty reserved to the Crown has a base rate of 10% and a rate cap of 35% for oil pools discovered prior to April 1, 1974.

In Alberta, the royalty reserved to the Crown in respect of natural gas production, subject to various incentives, is between 15% and 30%, in the case of new gas, and between 15% and 35%, in the case of old gas, depending upon a prescribed reference or corporate average price. Natural gas produced from qualifying exploratory gas wells spudded or deepened after July 31, 1985 and before June 1, 1988 is eligible for a royalty exemption for a period of 12 months, up to a prescribed maximum amount. Natural gas produced from qualifying intervals in eligible gas wells spudded or deepened to a depth below 2,500 meters is also subject to a royalty exemption, the amount of which depends on the depth of the well.

In Alberta, a producer of oil or natural gas is entitled to a credit against the royalties payable to the Crown by virtue of the ARTC program. The ARTC rate is based on a price sensitive formula and the ARTC rate varies between 75% at prices at and below $100 per m^3 and 25% at prices at and above $210 per m^3. The ARTC rate is applied to a maximum of $2,000,000 of Alberta Crown royalties payable for each producer or associated group of producers. Crown royalties on production from producing properties acquired from a corporation claiming maximum entitlement to ARTC will generally not be eligible for ARTC. The rate will be established quarterly based on the average "par price", as determined by the Alberta Department of Energy for the previous quarterly period.

On December 22, 1997, the Alberta government announced that it was conducting a review of the ARTC program with the objective of setting out better targeted objectives for a smaller program and to deal with administrative difficulties. On August 30, 1999, the Alberta government announced that it would not be reducing the size of the program but that it would introduce new rules to reduce the number of persons who qualify for the program. These rules preclude companies that pay less than $10,000 in royalties per year and non-corporate entities from qualifying for the program. Such rules do not presently preclude Highpine from being eligible for the ARTC program.

In November 2003, the Tax Act was amended to provide the following initiatives applicable to the oil and gas industry to be phased in over a five year period: (i) a reduction of the federal statutory corporate income tax rate on income earned from resource activities from 28 to 21%, beginning with a one percentage point reduction effective January 1, 2003, and (ii) a deduction for federal income tax purposes of actual provincial and other Crown royalties and mining taxes paid and the elimination of the 25% resource allowance. In addition, the percentage of ARTC that Highpine will be required to include in federal taxable income will be 17.5% in 2005; 32.5% in 2006; 50% in 2007; 50% in 2007; 60% in 2008; 70% in 2009; 80% in 2010; 90% in 2011; and 100% in 2012 and beyond.

Producers of oil and natural gas in the Province of British Columbia are also required to pay annual rental payments in respect of Crown leases and royalties and freehold production taxes in respect of oil and gas produced from Crown and freehold lands, respectively. The amount payable as a royalty in respect of oil depends on the vintage of the oil, the quantity of oil produced in a month and the value of the oil. Oil produced from newly discovered pools may be exempt from the payment of a royalty for the first 36 months of production. The royalty payable on natural gas is determined by a sliding scale based on a reference price which is the greater of the amount obtained by the producer and a prescribed minimum price. Gas produced in association with oil has a minimum royalty of 8% while the royalty in respect of other gas may not be less than 15%.

On May 30, 2003, the Ministry of Energy and Mines for British Columbia announced an Oil and Gas Development Strategy for the Heartlands (the "**Strategy**"). The Strategy is a comprehensive program to address road infrastructure, targeted royalties, and regulatory reduction and British Columbia service-sector opportunities.

Some of the financial incentives in the Strategy include:

Royalty credits of up to $10 million annually towards the construction, upgrading and maintenance of road infrastructure in support of resource exploration and development. Funding will be contingent upon an equal contribution from industry.

Changes to provincial royalties: new royalty rates for low-productivity natural gas to enhance marginally economic resources plays, royalty credits for deep gas exploration to locate new sources of natural gas, and royalty credits for summer drilling to expand the drilling season.

Land Tenure

Crude oil and natural gas located in the western provinces is owned predominantly by the respective provincial governments. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licenses and permits for varying terms, usually from two to five years, and on conditions set forth in provincial legislation, including requirements to perform specific work or make payments. Oil and natural gas located in such provinces can also be privately owned and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations. In addition, such legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage and the imposition of material fines and penalties.

Environmental legislation in Alberta has been consolidated into the *Alberta Environmental Protection and Enhancement Act* (the "**APEA**"), which came into force on September 1, 1993. The APEA imposes stricter environmental standards, requires more stringent compliance, reporting and monitoring obligations and significantly increases penalties. Highpine anticipates making increased expenditures of both a capital and an expense nature as a result of the increasingly stringent laws relating to the protection of the environment and will be taking such steps as required to ensure compliance with the APEA and similar legislation in other jurisdictions in which it operates. Highpine believes that it is in material compliance with applicable environmental laws and regulations. Highpine also believes that it is reasonably likely that the trend towards stricter standards in environmental legislation and regulation will continue.

British Columbia's *Environmental Assessment Act* became effective June 30, 1995. This legislation rolls the previous processes for the review of major energy projects into a single environmental assessment process which contemplates public participation in the environmental review.

RISK FACTORS

Highpine's securities should be considered highly speculative due to the nature of Highpine's business. An investor should consider carefully the risk factors set out below. In addition, investors should carefully review and consider all other information contained or incorporated by reference in this Annual Information Form before making an investment decision. An investment in securities of the Corporation should only be made by persons who can afford a significant or total loss of their investment.

Exploration, Development and Production Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of Highpine depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, Highpine's existing reserves and the production therefrom will decline over time as such existing reserves are exploited. A future increase in Highpine's reserves will depend not only on its ability to explore and develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. No assurance can be given that Highpine will be able to continue to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, Highpine may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by Highpine.

Future oil and natural gas exploration may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, cratering, sour gas releases and spills, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or personal injury. In particular, Highpine may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to Highpine. In accordance with industry practice, Highpine is not fully insured against all of these risks, nor are all such risks insurable. Although Highpine maintains liability insurance in an amount that it considers consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event Highpine could incur significant costs that could have a material adverse effect upon its financial condition. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks could have a material adverse effect on Highpine.

Operational Dependence

Other companies operate some of the assets in which Highpine has an interest. As a result, Highpine has limited ability to exercise influence over the operation of these assets or their associated costs, which could adversely affect Highpine's financial performance. Highpine's return on assets operated by others will therefore depend upon a number of factors that may be outside of Highpine's control, including the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

Project Risks

Highpine manages a variety of small and large projects in the conduct of its business. Project delays may delay expected revenues from operations. Significant project cost over-runs could make a project uneconomic.

Highpine's ability to execute projects and market oil and natural gas depends upon numerous factors beyond the Corporation's control, including:

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the supply of and demand for oil and natural gas;

- the availability of alternative fuel sources;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- the availability and productivity of skilled labour; and
- regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, Highpine could be unable to execute projects on time, on budget or at all, and may not be able to effectively market the oil and natural gas that it produces.

Competition

The petroleum industry is competitive in all its phases. Highpine competes with numerous other organizations in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. Highpine's competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than Highpine. Highpine's ability to increase reserves in the future will depend not only on its ability to explore and develop its present properties, but also on its ability to select and acquire other suitable producing properties or prospects for exploratory drilling. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery.

Regulatory

Oil and natural gas operations (exploration, production, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government, which may be amended from time to time. See "Industry Conditions". Governments may regulate or intervene with respect to price, taxes, royalties and the exportation of oil and natural gas. Such regulations may be changed from time to time in response to economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for natural gas and crude oil and increase Highpine's costs, any of which may have a material adverse effect on Highpine's business, financial condition and results of operations. In order to conduct oil and gas operations, Highpine requires licenses from various governmental authorities. There can be no assurance that Highpine will be able to obtain all of the licenses and permits that may be required to conduct operations that it may wish to undertake.

Kyoto Protocol

Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nationwide emissions of carbon dioxide, methane, nitrous oxide and other so-called "greenhouse gases". Highpine's exploration and production facilities and other operations and activities emit greenhouse gases which will likely subject Highpine to possible future legislation regulating emissions of greenhouse gases. The Government of Canada has put forward a Climate Change Plan for Canada, which suggests further legislation will set greenhouse gases emission reduction requirements for various industrial activities, including oil and gas exploration and production. Future federal legislation, together with provincial emission reduction requirements, such as those proposed in Alberta's Climate Change and Emissions Management Act (partially in force), may require the reduction of emissions (or emissions intensity) produced by the Corporation's operations and facilities. The direct or indirect costs of these regulations may adversely affect the business of the Corporation.

Environmental

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require Highpine to incur costs to remedy such discharge. Although Highpine believes that it is in material compliance with current applicable environmental regulations no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise adversely affect Highpine's financial condition, results of operations or prospects. See "Industry Conditions – Environmental Regulation".

Prices, Markets and Marketing

The marketability and price of oil and natural gas that may be acquired or discovered by Highpine is and will continue to be affected by numerous factors beyond its control. Highpine's ability to market its oil and natural gas may depend upon its ability to acquire space on pipelines that deliver natural gas to commercial markets. Highpine may also be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing facilities and operational problems affecting such pipelines and facilities as well as extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business.

Both oil and natural gas prices are unstable and are subject to fluctuation. Any material decline in prices could result in a reduction of Highpine's net production revenue. The economics of producing from some wells may change as a result of lower prices, which could result in reduced production of oil or gas and a reduction in the volumes of Highpine's reserves. Highpine might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in Highpine's net production revenue and a reduction in its oil and gas acquisition, development and exploration activities. In addition, bank borrowings available to Highpine are in part determined by Highpine's borrowing base. A sustained material decline in prices from historical average prices could reduce Highpine's borrowing base, therefore reducing the bank credit available to Highpine which could require that a portion, or all, of Highpine's bank debt be repaid and a liquidation of assets.

Substantial Capital Requirements

Highpine anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. If Highpine's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future drilling programs. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to Highpine. The inability of Highpine to access sufficient capital for its operations could have a material adverse effect on Highpine's financial condition, results of operations and prospects.

Additional Funding Requirements

Highpine's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times. From time to time, Highpine may require additional financing in order to carry out its oil and gas acquisition, exploration and development activities. Failure to obtain such financing on a timely basis could cause Highpine to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If Highpine's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, Highpine's ability to expend the necessary capital to replace its reserves or to maintain its production will be impaired. If Highpine's cash flow from operations is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or, if available, on favourable terms.

Issuance of Debt

From time to time Highpine may enter into transactions to acquire assets or the shares of other organizations. These transactions may be financed in whole or in part with debt, which may increase Highpine's debt levels above industry standards for oil and natural gas companies of similar size. Depending on future exploration and development plans, Highpine may require additional equity and/or debt financing that may not be available or, if available, may not be available on favourable terms. Neither Highpine's articles nor its by-laws limit the amount of indebtedness that Highpine may incur. The level of Highpine's indebtedness from time to time, could impair Highpine's ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

Hedging

From time to time Highpine may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline; however, if commodity prices increase beyond the levels set in such agreements, Highpine will not benefit from such increases. Similarly, from time to time Highpine may enter into agreements to fix the exchange rate of Canadian to United States dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar; however, if the Canadian dollar declines in value compared to the United States dollar, Highpine will not benefit from the fluctuating exchange rate.

Availability of Drilling Equipment and Access

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment (typically leased from third parties) in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to Highpine and may delay exploration and development activities. To the extent Highpine is not the operator of its oil and gas properties, Highpine will be dependent on such operators for the timing of activities related to such properties and will be largely unable to direct or control the activities of the operators.

Title to Assets

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat Highpine's claim which could result in a reduction of the revenue received by Highpine.

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and NGL reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth in this Annual Information Form are estimates only. In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. All such estimates are to some degree speculative, and classifications of reserves are only attempts to define the degree of speculation involved. For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times, may vary. Highpine's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material.

Estimates of proved reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. In Highpine's case, 60% of proved reserves are estimated using volumetric analysis. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history and production practices will result in variations in the estimated reserves and such variations could be material.

In accordance with applicable securities laws, Paddock has used both constant and escalated prices and costs in estimating the reserves and future net cash flows contained in the Highpine Paddock Report and the White Fire Paddock Report. Actual future net cash flows will be affected by other factors, such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

Actual production and cash flows derived from Highpine's oil and gas reserves will vary from the estimates contained in the Highpine Paddock Report and White Fire Paddock Report, and such variations could be material. The Highpine Paddock Report and White Fire Paddock Report are based in part on the assumed success of activities Highpine intends to undertake in future years. The reserves and estimated cash flows set out in the Highpine Paddock Report and White Fire Paddock Report will be reduced to the extent that such activities do not achieve the level of success assumed in the Highpine Paddock Report and White Fire Paddock Report.

Insurance

Highpine's involvement in the exploration for and development of oil and natural gas properties may result in Highpine becoming subject to liability for pollution, blow outs, property damage, personal injury or other hazards. Although Highpine maintains insurance in accordance with industry standards to address certain of these risks, such insurance has limitations on liability and may not be sufficient to cover the full extent of such liabilities. In addition, such risks are not, in all circumstances, insurable or, in certain circumstances, Highpine may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of any uninsured liabilities would reduce the funds available to Highpine. The occurrence of a significant event that Highpine is not fully insured against, or the insolvency of the insurer of such event, could have a material adverse effect on Highpine.

Dividends

To date, other than the Stock Dividend, Highpine has not declared or paid any dividends on the outstanding Common Shares or Series 1 Class B Shares (as such term is defined herein). Any decision to pay dividends on the Common Shares will be made by the Board of Directors on the basis of Highpine's earnings, financial requirements and other conditions existing at such future time. At present, Highpine does not anticipate declaring and paying any dividends in the near future.

Conflicts of Interest

Certain directors of Highpine are also directors of other oil and gas companies and as such may, in certain circumstances, have a conflict of interest requiring them to abstain from certain decisions. Conflicts, if any, will be subject to the procedures and remedies of the ABCA. See "Directors and Executive Officers – Conflicts of Interest".

Dilution

Highpine may make further acquisitions or enter into financings or other transactions involving the issuance of securities of Highpine which may be dilutive.

Management of Growth

The Corporation may be subject to growth-related risks including capacity constraints and pressure on its internal systems and controls. The ability of the Corporation to manage growth effectively will require it to continue to implement and improve its operational and financial systems and to expand, train and manage its employee base. The inability of the Corporation to deal with this growth could have a material adverse impact on its business, operations and prospects.

Expiration of Licenses and Leases

The Corporation's properties are held in the form of licences and leases and working interests in licences and leases. If the Corporation or the holder of the licence or lease fails to meet the specific requirement of a licence or lease, the licence or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each licence or lease will be met. The termination or expiration of the Corporation's licences or leases or the working interests relating to a licence or lease may have a material adverse effect on the Corporation's results of operations and business.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to portions of western Canada. The Corporation is not aware that any claims have been made in respect of its property and assets, however, if a claim arose and was successful this could have an adverse effect on the Corporation and its operations.

Seasonality

The level of activity in the Canadian oil and gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain oil and gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding declines in the demand for the goods and services of the Corporation.

Third Party Credit Risk

The Corporation is or may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. In the event such entities fail to meet their contractual obligations to the Corporation, such failures could have a material adverse effect on the Corporation and its cash flow from operations. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in the Corporation's ongoing capital program, potentially delaying the program and the results of such program until the Corporation finds a suitable alternative partner.

Reliance on Key Personnel

Highpine's success depends in large measure on certain key personnel. The loss of the services of such key personnel could have a material adverse affect on Highpine. Highpine does not have any key person insurance in effect for management. The contributions of the existing management team to the immediate and near term operations of Highpine are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that Highpine will be able to continue to attract and retain all personnel necessary for the development and operation of its business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of Highpine.

DIVIDENDS

Highpine has not declared or paid any dividends on the Common Shares or Series 1 Class B Shares during the three most recently completed financial years except for the Stock Dividend. Any decision to pay dividends on the Common Shares will be made by the Board of Directors on the basis of Highpine's earnings, financial requirements and other conditions existing at such future time. There are no restrictions that could prevent the Corporation from paying dividends.

DESCRIPTION OF CAPITAL STRUCTURE

Highpine is authorized to issue an unlimited number of Common Shares and an unlimited number of Class B Shares, each having the rights, privileges, restrictions and conditions described below.

Common Shares

Highpine is authorized to issue an unlimited number of Common Shares without nominal or par value. Holders of Common Shares are entitled to one vote per share at meetings of shareholders of Highpine, except meetings of another class or series of shares of Highpine, which are required by law to be held separately. Subject to the rights of the holders of any other shares having priority over the Common Shares, holders of Common Shares are entitled to dividends if, as and when declared by the Board of Directors and, upon liquidation, dissolution or winding-up, to receive the remaining property of Highpine.

Class B Shares

Highpine is authorized to issue an unlimited number of Class B Shares issuable in series, each series consisting of such number of shares and having such rights, privileges, restrictions and conditions as may be determined by the Board of Directors of Highpine prior to the issuance thereof. Subject to applicable law, the holders of Class B Shares are not entitled to receive notice of, attend or vote at any meetings of the shareholders of the Corporation. The holders of Class B Shares are not entitled to receive any dividends on the Class B Shares and are not be entitled, in the event of any liquidation, dissolution or winding-up of the

Corporation, whether voluntary or involuntary, or any other distribution of the assets of the Corporation among its shareholders for the purpose of winding-up its affairs, to receive the remaining property of Highpine.

MARKET FOR SECURITIES

The Common Shares are listed and posted for trading on the TSX under the symbol "HPX". The following table sets forth the high and low sales prices (which are not necessarily the closing prices) and the trading volumes for the Common Shares on the TSX as reported by the TSX for the periods indicated, commencing with the date upon which the Common Shares began trading on the TSX:

	Price Range ($)		Trading
Period	**High**	**Low**	**Volume**
2005			
April 5 to April 30 [(1)]	20.25	17.40	4,062,400
May	18.30	16.60	2,479,000
June	20.95	18.00	3,997,700
July	23.21	20.00	2,820,900
August	23.30	20.60	3,758,100
September	23.95	20.95	2,862,000
October	24.15	20.02	3,063,300
November	22.24	19.30	1,710,300
December	24.75	20.56	1,682,700
2006			
January	24.66	20.80	3,890,300
February	24.75	21.25	3,591,000
March (1 – 27)	22.90	21.30	2,323,600

Note:

(1) The Common Shares began trading on the TSX on April 5, 2005.

PRIOR SALES

There is no class of securities of Highpine that is outstanding but not listed or quoted on a marketplace.

ESCROWED SECURITIES

The following table sets forth the number of securities of each class of the Corporation held in escrow and the percentage of the outstanding securities of the class.

Designation of Class	Number of Securities Held in Escrow	Percentage of Class
Common Shares	268,604	0.5%

Note:

(1) Pursuant to the terms of the White Fire Arrangement, Robert Rosine, Robert Fryk, Dave Humphreys and Rob Pinckston, who were appointed executive officers of Highpine upon completion of the White Fire Arrangement, deposited all of the Common Shares which they received pursuant to the White Fire Arrangement, being an aggregate of 153,488 Common Shares, in escrow with Burnet, Duckworth & Palmer LLP, Highpine's legal counsel, which Common Shares will be releasable to them as to one-third thereof on each of April 23, 2007, April 23, 2008 and April 23, 2009, provided that they are an employee of Highpine on the release dates. In addition, Kenneth Woolner, who was appointed a director of Highpine upon completion of the White Fire Arrangement, deposited 76,744 Common Shares received by him pursuant to the White Fire Arrangement in escrow with Burnet, Duckworth & Palmer LLP, which Common Shares will be releasable to him as to one-third thereof on each of April 23, 2007, April 23, 2008 and April 23, 2009. In addition, certain other employees of White Fire who continued as employees of Highpine on the effective date of the White Fire Arrangement, deposited an aggregate of 38,372 Common Shares which they received pursuant to the White Fire Arrangement in escrow with Burnet, Duckworth & Palmer LLP, which Common Shares will be releasable to them as to one-third thereof on each of August 31, 2006, February 28, 2007 and August 31, 2007.

DIRECTORS AND EXECUTIVE OFFICERS

Name, Occupation and Security Holding

The following table sets forth certain information in respect of Highpine's directors and executive officers:

Name, Province/State and Country of Residence	Position(s) with Highpine (1)	Principal Occupation During the Five Preceding Years
A. Gordon Stollery Alberta, Canada	Chairman, Chief Executive Officer and Director	Chairman and Chief Executive Officer of Highpine since February 2006; and prior thereto, Chairman, President and Chief Executive Officer of Highpine.
John A. Brussa (3) Alberta, Canada	Director	Partner, Burnet, Duckworth & Palmer LLP (law firm).
Richard G. Carl (2)(3)(4) Ontario, Canada	Director	Special Advisor to TerraNova Partners L.P. (oil and gas investment limited partnership) since January 2006; Interim President and Chief Executive Officer of Collective Bid Systems Inc. and CBID Markets Inc. (electronic fixed income trading platform offering trading services in the Canadian fixed income market to retail and institutional investors) from July 2005 to December 2005; and prior thereto, Managing Partner, Lawrence & Company Inc. (investment firm).
Andrew Krusen (2)(4) Florida, United States	Director	Chairman, President and Chief Executive Officer, Dominion Financial Group Inc. (investment and financial services firm).
Hank B. Swartout (2)(3) Alberta, Canada	Director	Chief Executive Officer, Precision Drilling Corporation (administrator to Precision Drilling Trust, an oil and gas services trust) since November 2005; and prior thereto Chairman, President and Chief Executive Officer, Precision Drilling Corporation (oil and gas services company).
Robert N. Waldner Alberta, Canada	Director	President and Chief Executive Officer of Vaquero Resources Ltd. (oil and gas company) since September 2005; Independent businessman from May 2005 to September 2005; and prior thereto President and Chief Executive Officer of Vaquero from July 2001 to May 2005.
Kenneth S. Woolner (4) Alberta, Canada	Director	Independent businessman since February 2006; prior thereto, Executive Chairman of White Fire since April 2005; President and Chief Executive Officer of Lightning Energy Ltd. (oil and gas company) from December 2001 to April 2005; and prior thereto, President of Velvet Exploration Ltd. (oil and gas company) from April 1997 to July 2001.
Greg N. Baum Alberta, Canada	President and Chief Operating Officer	President and Chief Operating Officer of Highpine since February 2006; and prior thereto, Executive Vice President and Chief Operating Officer of Highpine.

Name, Province/State and Country of Residence	Position(s) with Highpine [1]	Principal Occupation During the Five Preceding Years
Robert W. Rosine Alberta, Canada	Executive Vice President, Corporate Development	Executive Vice President, Corporate Development of Highpine since February 2006; Chief Executive Officer of White Fire from April 2005 to February 2006; Chief Operating Officer of Lightning Energy Ltd. (oil and gas company) from June 2004 to April 2005; President of Brooklyn Energy Corporation (oil and gas company) from November 2001 to June 2004; and prior thereto President of Maxx Petroleum Ltd. (oil and gas company) from December 1998 to November 2000.
Harry D. Cupric Alberta, Canada	Vice President, Finance and Chief Financial Officer	Vice President, Finance and Chief Financial Officer of Highpine since January 2003; and prior thereto Vice President, Finance and Chief Financial Officer of Ascot Energy Resources Ltd. (oil and gas company).
Robert B. Fryk Alberta, Canada	Senior Vice President, Engineering and Operations	Senior Vice President, Engineering and Operations of Highpine since February 2006; Chief Operating Officer of White Fire from April 2005 to February 2006; Vice President, Engineering and Acquisitions of Lightning Energy Ltd. (oil and gas company) from June 2004 to April 2005; Vice President, Engineering and Operations of Brooklyn Energy Corporation (oil and gas company) from November 2001 to June 2004; and prior thereto Vice President and Chief Operating Officer and Vice President, Engineering and Operations of Maxx Petroleum Ltd. (oil and gas company) from November 1998 to May 2001.
Dave Humphreys Alberta, Canada	Vice President, Operations	Vice President, Operations of Highpine since February 2006; Vice President, Operations of White Fire from April 2005 to February 2006; Vice President, Operations of Virtus Energy Ltd. (oil and gas company) from April 2003 to April 2005; and prior thereto Production Manager of Husky Oil and Production Manager of Ionic Energy Ltd.
Rob Pinckston Alberta, Canada	Vice President, W5M Gas	Vice President, W5M Gas of Highpine since February 2006; Vice President, Exploration of White Fire from April 2005 to February 2006; and prior thereto Exploration Manager and founder of Tempest Energy from January 2001 to March 2005.
Wayne Gray Alberta, Canada	Vice President, Land	Vice President, Land of Highpine since September 2002; and prior thereto Vice President, Land of Trident Exploration Ltd. (oil and gas company).
Doug McArthur Alberta, Canada	Senior Vice President, Exploration	Senior Vice President, Exploration of Highpine since February 2006; and prior thereto, Vice President and Chief Geologist of Highpine.
Fred D. Davidson Alberta, Canada	Corporate Secretary	Partner, Burnet, Duckworth & Palmer LLP (law firm).

Notes:

(1) All of the directors of Highpine have been appointed to hold office until the next annual general meeting of shareholders or until their successor is duly elected or appointed, unless their office is earlier vacated. Mr. Stollery has been a director of Highpine since April 1998, Messrs. Brussa, Krusen and Swartout have been directors of Highpine since February 2000, Mr. Carl has been a director since August 2003, Mr. Waldner has been a director since July 2005 and Mr. Woolner has been a director since February 2006.

(2) Member of the Audit Committee.

(3) Member of the Compensation, Nominating and Corporate Governance Committee.

(4) Member of the Reserves Committee.

(5) Highpine does not have an Executive Committee.

As at the date of this Annual Information Form, the number of Common Shares beneficially owned, directly or indirectly, by all of the directors and officers of Highpine is 10,956,000 Common Shares, being approximately 21% of the issued and outstanding Common Shares.

Conflicts of Interest

There are potential conflicts of interest to which the directors and officers of Highpine will be subject in connection with the operations of Highpine. In particular, certain of the directors and officers of Highpine are involved in managerial or director positions with other oil and gas companies whose operations may, from time to time, be in direct competition with those of Highpine or with entities which may, from time to time, provide financing to, or make equity investments in, competitors of Highpine. Conflicts, if any, will be subject to the procedures and remedies available under the ABCA. The ABCA provides that in the event that a director has an interest in a contract or proposed contract or agreement, the director shall disclose his interest in such contract or agreement and shall refrain from voting on any matter in respect of such contract or agreement unless otherwise provided by the ABCA.

LEGAL PROCEEDINGS

There are no material legal proceedings to which the Corporation is a party or in respect of which any of its property is the subject, nor are any such proceedings known to the Corporation to be contemplated.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There are no material interests, direct or indirect, of any director or executive officer of the Company, any person or company that is the direct or indirect owner of, or who exercises control or direction of, more than 10% of any class or series of the Corporation's outstanding voting securities, or any associate or affiliate of any of the foregoing persons or companies, in any transaction during the year ended December 31, 2005 or during the current financial year that has materially affected or will materially affect the Corporation, other than as disclosed elsewhere in this Annual Information Form. John A. Brussa, a director of Highpine, and Fred D. Davidson, the Corporate Secretary of Highpine, are partners of Burnet, Duckworth & Palmer LLP, which firm receives fees for legal services provided to Highpine.

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for the Common Shares is Valiant Trust Company at its principal offices in Calgary, Alberta and its agent's offices in Toronto, Ontario.

MATERIAL CONTRACTS

Other than contracts entered into in the ordinary course of business, there are no material contracts entered into by Highpine during the year ended December 31, 2005 which can reasonably be regarded as presently material.

INTEREST OF EXPERTS

Names of Experts

The only persons or companies who are named as having prepared or certified a statement, report or valuation described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by the Corporation during, or relating to, the

Corporation's most recently completed financial year, and whose profession or business gives authority to the statement, report or valuation made by the person or company, are KPMG LLP, the Corporation's independent auditors and Paddock, the Corporation's independent engineering evaluators.

Interests of Experts

To the Corporation's knowledge, no registered or beneficial interests, direct or indirect, in any securities or other property of the Corporation or of one of the Corporation's associates or affiliates (i) were held by Paddock, when Paddock prepared the statement, report or valuation in question, (ii) were received by Paddock after Paddock prepared the statement, report or valuation in question, or (iii) is to be received by Paddock.

As at March 27, 2006, KPMG and its partners did not hold any registered or beneficial ownership interests, directly or indirectly, in the securities of the Corporation or its associates or affiliates.

AUDIT COMMITTEE INFORMATION

Composition of the Audit Committee

The Audit Committee of the Corporation is comprised of Richard G. Carl (Chair), Andrew Krusen and Hank B. Swartout. The following table sets out the assessment of each Audit Committee member's independence, financial literacy and relevant educational background and experience supporting such financial literacy.

Name and Municipality of Residence	Independent	Financially Literate	Relevant Education and Experience
Richard G. Carl Toronto, Ontario	Yes	Yes	Mr. Carl has been a Special Advisor to TerraNova Partners L.P., an oil and gas investment limited partnership, since January 2006 and was the Interim President and Chief Executive Officer of Collective Bid Systems Inc. and CBID Markets Inc., an electronic fixed income trading platform offering trading services in the Canadian fixed income market to retail and institutional investors, from July 2005 to December 2005. Prior thereto, Mr. Carl was the Managing Partner of Lawrence & Company Inc., a Toronto-based investment firm specializing in investing in North American private and public companies and money management from April 2002 until July 2005. From June 2001 until April 2002, Mr. Carl was the President of his financial and consulting services company, the Blackwell Group. From June 1999 to June 2001, Mr. Carl was the Canadian President of Credit Suisse First Boston Canada Inc. (an investment company), where he was responsible for sales, trading, research and equity capital markets in Canada. Mr. Carl was also responsible for the regional oversight, compliance, regulatory matters and management of Credit Suisse First Boston Canada Inc. From April 1993 until June 1999, Mr. Carl was the Senior Vice President of Nesbitt Burns Inc., an investment banking firm. Mr. Carl has extensive experience in raising capital and mergers and acquisition advisory work to corporations across Canada. Mr. Carl obtained a Bachelor of Commerce and Finance from the University of Toronto in 1980 and has been a Chartered Financial Analyst of the Association of Investment Management Research since 1983.

Name and Municipality of Residence	Independent	Financially Literate	Relevant Education and Experience
Andrew Krusen Tampa, Florida	Yes	Yes	Mr. Krusen has been the Chairman and Chief Executive Officer of Dominion Financial Group, Inc., a financial services company, since 1990. Mr. Krusen has served on the board of numerous public companies and currently serves on the board of Memry Corporation, a company listed on the American Stock Exchange, and Trinsic, Inc., a company listed on NASDAQ. Mr. Krusen obtained a Bachelor of Arts in Geology from Princeton University in 1970.
Hank B. Swartout Calgary, Alberta	Yes	Yes	Mr. Swartout has been the Chief Executive Officer of Precision Drilling Corporation, the administrator to Precision Drilling Trust, an oil and gas services trust listed on the Toronto Stock Exchange and New York Stock Exchange, since November 2005. From July 1987 until November 2005, Mr. Swartout was the Chairman, President and Chief Executive Officer of Precision Drilling Corporation, an oil and gas services company listed on the Toronto Stock Exchange and New York Stock Exchange. Mr. Swartout obtained a Petroleum Engineering Degree with honours from the University of Wyoming in 1977.

Pre-Approval of Policies and Procedures

Under the Mandate and Terms of Reference of the Audit Committee, the Audit Committee is required to review and pre-approve any non-audit services to be provided to the Corporation or its subsidiaries by the external auditors and consider the impact on the independence of such auditors. The Audit Committee may delegate to one or more independent members the authority to pre-approve non-audit services, provided that the member report to the Audit Committee at the next scheduled meeting such pre-approval and the member comply with such other procedures as may be established by the Audit Committee from time to time.

The Audit Committee has determined that in order to ensure the continued independence of the auditors, only limited non-audit related services will be provided to the Corporation by KPMG LLP and in such case, only with the prior approval of the Audit Committee.

Audit Committee Mandate and Terms of Reference

Role and Objective

The Audit Committee is a committee of the Board of Directors (the "**Board**") of the Corporation to which the Board has delegated its responsibility for the oversight of the nature and scope of the annual audit, the oversight of management's reporting on internal accounting standards and practices, the review of financial information, accounting systems and procedures, financial reporting and financial statements and has charged the Audit Committee with the responsibility of recommending, for approval of the Board, the audited financial statements, interim financial statements and other mandatory disclosure releases containing financial information.

The primary objectives of the Audit Committee are as follows:

1. to assist directors in meeting their responsibilities (especially for accountability) in respect of the preparation and disclosure of the financial statements of the Corporation and related matters;
2. to provide better communication between directors and external auditors;
3. to enhance the external auditors' independence;
4. to increase the credibility and objectivity of financial reports; and

5. to strengthen the role of the independent directors by facilitating in depth discussions between directors on the Audit Committee, management and external auditors.

Membership of Audit Committee

1. The Audit Committee will be comprised of at least three (3) directors of the Corporation or such greater number as the Board of Directors may determine from time to time and all members of the Audit Committee shall be "independent" (as such term is used in Multilateral Instrument 52-110 – Audit Committees ("**MI 52-110**") unless the Board determines that the exemption contained in MI 52-110 is available and determines to rely thereon.
2. The Board of Directors may from time to time designate one of the members of the Audit Committee to be the Chair of the Audit Committee.
3. All of the members of the Audit Committee must be "financially literate" (as defined in MI 52-110) unless the Board determines that an exemption under MI 52-110 from such requirement in respect of any particular member is available and determines to rely thereon in accordance with the provisions of MI 52-110.

Mandate and Responsibilities of Audit Committee

It is the responsibility of the Audit Committee to:

1. Oversee the work of the external auditors, including the resolution of any disagreements between management and the external auditors regarding financial reporting.

2. Satisfy itself on behalf of the Board with respect to the Corporation's internal control systems:

    - identifying, monitoring and mitigating business risks; and

    - ensuring compliance with legal, ethical and regulatory requirements.

3. Review the annual and interim financial statements of the Corporation and related management's discussion and analysis ("**MD&A**") prior to their submission to the Board for approval. The process should include but not be limited to:

    - reviewing changes in accounting principles and policies, or in their application, which may have a material impact on the current or future years' financial statements;
    - reviewing significant accruals, reserves or other estimates such as the ceiling test calculation;
    - reviewing accounting treatment of unusual or non-recurring transactions;
    - ascertaining compliance with covenants under loan agreements;
    - reviewing disclosure requirements for commitments and contingencies;
    - reviewing adjustments raised by the external auditors, whether or not included in the financial statements;
    - reviewing unresolved differences between management and the external auditors; and
    - obtain explanations of significant variances with comparative reporting periods.

4. Review the financial statements, prospectuses and other offering documents, MD&A, annual information forms ("**AIF**") and all public disclosure containing audited or unaudited financial information (including, without limitation, annual and interim press releases and any other press releases disclosing earnings or financial results) before release and prior to Board approval. The Audit Committee must be satisfied that adequate procedures are in place for the review of the Corporation's disclosure of all other financial information and will periodically assess the accuracy of those procedures.

5. Review and approve the disclosure of audit committee information required to be included in the AIF of the Corporation prior to its filing with regulatory authorities.

6. With respect to the appointment of external auditors by the Board:

    - recommend to the Board the external auditors to be nominated;

- recommend to the Board the terms of engagement of the external auditors, including the compensation of the auditors and a confirmation that the external auditors will report directly to the Audit Committee;
- on an annual basis, review and discuss with the external auditors all significant relationships such auditors have with the Corporation to determine the auditors' independence;
- when there is to be a change in auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change; and
- review and pre-approve any non-audit services to be provided to the Corporation or its subsidiaries by the external auditors and consider the impact on the independence of such auditors. The Audit Committee may delegate to one or more independent members the authority to pre-approve non-audit services, provided that the member(s) report to the Audit Committee at the next scheduled meeting such pre-approval and the member(s) comply with such other procedures as may be established by the Audit Committee from time to time.

7. Review with external auditors (and internal auditor if one is appointed by the Corporation) their assessment of the internal controls of the Corporation, their written reports containing recommendations for improvement, and management's response and follow-up to any identified weaknesses. The Audit Committee will also review annually with the external auditors their plan for their audit and, upon completion of the audit, their reports upon the financial statements of the Corporation and its subsidiaries.

8. Review risk management policies and procedures of the Corporation (i.e. hedging, litigation and insurance).

9. Establish a procedure for:

   - the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting controls or auditing matters; and
   - the confidential, anonymous submission by employees of the Corporation of concerns regarding questionable accounting or auditing matters.

10. Review and approve the Corporation's hiring policies regarding partners and employees and former partners and employees of the present and former external auditors of the Corporation.

The Audit Committee has authority to communicate directly with the internal auditors (if any) and the external auditors of the Corporation. The external auditors shall be required to report directly to the Audit Committee. The Audit Committee will also have the authority to investigate any financial activity of the Corporation. All employees of the Corporation are to cooperate as requested by the Audit Committee.

The Audit Committee may also retain persons having special expertise and/or obtain independent professional advise to assist in filling their responsibilities at such compensation as established by the Audit Committee and at the expense of the Corporation without any further approval of the Board.

Meetings and Administrative Matters

1. At all meetings of the Audit Committee every question shall be decided by a majority of the votes cast. In case of an equality of votes, the Chairman of the meeting shall be entitled to a second or casting vote.

2. The Chair will preside at all meetings of the Audit Committee, unless the Chair is not present, in which case the members of the Audit Committee that are present will designate from among such members the Chair for purposes of the meeting.

3. A quorum for meetings of the Audit Committee will be a majority of its members, and the rules for calling, holding, conducting and adjourning meetings of the Audit Committee will be the same as those governing the Board unless otherwise determined by the Audit Committee or the Board.

4. Meetings of the Audit Committee should be scheduled to take place at least four times per year. Minutes of all meetings of the Audit Committee will be taken. The Chief Financial Officer will attend meetings of the Audit Committee, unless otherwise excused from all or part of any such meeting by the Chairman.

5. The Audit Committee will meet with the external auditors at least once per year (in connection with the preparation of the year-end financial statements) and at such other times as the external auditors and the Audit Committee consider appropriate.

6. Agendas, approved by the Chair, will be circulated to Audit Committee members along with background information on a timely basis prior to the Audit Committee meetings.

7. The Audit Committee may invite such officers, directors and employees of the Corporation as it sees fit from time to time to attend at meetings of the Audit Committee and assist in the discussion and consideration of the matters being considered by the Audit Committee.

8. Minutes of the Audit Committee will be recorded and maintained and circulated to directors who are not members of the Audit Committee or otherwise made available at a subsequent meeting of the Board.

9. The Audit Committee may retain persons having special expertise and may obtain independent professional advice to assist in fulfilling its responsibilities at the expense of the Corporation.

10. Any members of the Audit Committee may be removed or replaced at any time by the Board and will cease to be a member of the Audit Committee as soon as such member ceases to be a director. The Board may fill vacancies on the Audit Committee by appointment from among its members. If and whenever a vacancy exists on the Audit Committee, the remaining members may exercise all its powers so long as a quorum remains. Subject to the foregoing, following appointment as a member of the Audit Committee each member will hold such office until the Audit Committee is reconstituted.

11. Any issues arising from these meetings that bear on the relationship between the Board and management should be communicated to the Chairman of the Board by the Audit Committee Chair.

External Auditors Service Fees

The following table sets forth the audit service fees billed by Highpine's external auditors, KPMG LLP, for the periods indicated:

Type of Fees and Fiscal Year Ended	Aggregate Fees Billed	Description of Services
Audit Fees		
Fiscal Year Ended December 31, 2005	$180,000	Audit of consolidated financial statements and review of interim financial statements
Fiscal Year Ended December 31, 2004	$50,000	Audit of consolidated financial statements
Audit – Related Fees		
Fiscal Year Ended December 31, 2005	$95,000	Professional services rendered with respect to the completion of the Initial Public Offering and the information circular in connection with the Vaquero Arrangement
Fiscal Year Ended December 31, 2004	$87,500	Review of consolidated financial statements for the nine months ended September 30, 2004 and 2003 and involvement with the Initial Public Offering
Tax Fees		
Fiscal Year Ended December 31, 2005	$33,620	Various taxation matters
Fiscal Year Ended December 31, 2004	$41,064	Various taxation matters
All Other Fees		
Fiscal Year Ended December 31, 2005	$nil	Not applicable
Fiscal Year Ended December 31, 2004	$nil	Not applicable

ADDITIONAL INFORMATION

Additional information relating to Highpine may be found on SEDAR at www.sedar.com and also on Highpine's website at www.highpineog.com.

Additional information, including directors' and officers' remuneration and indebtedness, principal holders of Highpine's securities and securities authorized for issuance under equity compensation plans is contained in Highpine's information circular – proxy statement dated March 20, 2006 relating to the annual general meeting of shareholders to be held on May 10, 2006.

Additional information is also provided in Highpine's consolidated financial statements and management's discussion and analysis for the year ended December 31, 2005, which documents may be found on SEDAR at www.sedar.com.

GLOSSARY OF TERMS

"**665162**" means 665162 B.C. Ltd., a corporation incorporated pursuant to the *Business Corporations Act* (British Columbia);

"**ABCA**" means the *Business Corporations Act* (Alberta), together with any amendments thereto and all regulations promulgated thereunder;

"**AEUB**" means the Alberta Energy and Utilities Board;

"**ARTC**" means Alberta Royalty Tax Credit;

"**Class B Shares**" means class B common non-voting shares in the capital of Highpine, issuable in series;

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum;

"**Common Shares**" means class A common voting shares in the capital of Highpine;

"**Corporation**" or "**Highpine**" means Highpine Oil & Gas Limited, a corporation incorporated pursuant to the ABCA and, unless the context otherwise requires, includes HAC, Pino Alto, Rubicon, Highpine Partnership, Highpine Energy, 665162 and White Fire;

"**Easyford Battery**" means the sour oil processing battery located at 11-14-50-8 W5M, which is approximately 15 kilometres north of Drayton Valley, Alberta;

"**Economic Life**" means, with respect to an oil and natural gas property, the time remaining before production of Petroleum Substances from the property is forecast to be uneconomic under forecast cost and price assumptions;

"**GAAP**" means Canadian generally accepted accounting principles;

"**HAC**" means Highpine Asset Corporation, a corporation incorporated pursuant to the ABCA;

"**Highpine Energy**" means Highpine Energy Ltd. (formerly Vaquero Energy Ltd.), a corporation incorporated pursuant to the ABCA;

"**Highpine Paddock Report**" means the February 3, 2006 report prepared by Paddock, evaluating the crude oil, natural gas and NGL reserves of Highpine, as at December 31, 2005, in accordance with the standards contained in the COGE Handbook and the reserves definitions set out by the Canadian Securities Administrators in NI 51-101 and the COGE Handbook;

"**Highpine Partnership**" means Highpine Oil & Gas Partnership, a general partnership organized under the laws of the Province of Alberta;

"**Initial Public Offering**" the initial public offering of 4,000,000 Common Shares of the Corporation at a price of $18.00 per Common Share completed on April 5, 2005;

"**Joffre Gas Plant**" means the natural gas processing plant located at 6-17-40-27 W4M, which is approximately 30 kilometres north of Red Deer, Alberta;

"**NI 51-101**" means National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities adopted by the Canadian Securities Administrators;

"**Paddock**" means Paddock Lindstrom & Associates Ltd., independent petroleum consultants, Calgary, Alberta;

"**Petroleum Substances**" means petroleum, natural gas and related hydrocarbons, (including condensate and NGLs) and all other substances (including sulphur and its compounds), whether liquid, solid or gaseous and whether hydrocarbons or not, produced in association therewith;

"**Pino Alto**" means Pino Alto Energy II Ltd., a corporation incorporated pursuant to the ABCA;

"**Reserve Value**" means, for any petroleum and natural gas property at any time, the present worth of all of the estimated pre-tax net cash flow from the total proved plus probable reserves shown in the most recent engineering report relating to such property, discounted at 10% and using forecast price and cost assumptions (a common benchmark in the oil and natural gas industry);

"**Rubicon**" means Rubicon Energy Corporation, a corporation formed by amalgamation pursuant to the ABCA;

"**Rubicon Acquisition**" means the indirect acquisition by Highpine of an undivided 50% interest in all of the assets of Rubicon (and assumption of related liabilities) in March 2004 for approximately $51 million;

"**Series 1 Class B Shares**" means class B common non-voting shares, series 1, in the capital of Highpine;

"**Special Warrants**" means the 3,300,000 special warrants issued by the Corporation on October 20, 2004, at a price of $9.00 per special warrant, pursuant to a special warrant indenture dated as of October 20, 2004 between the Corporation and Valiant Trust Company;

"**Stock Dividend**" means the stock dividend declared by the Corporation effective February 15, 2005 of 0.047 of a Common Share in respect of each issued and outstanding Common Share as at February 15, 2005. No fractional Common Shares were issued and in the case that the stock dividend resulted in a shareholder becoming entitled to receive 0.5 or more of a Common Share, an adjustment was made to round up to the next number of whole Common Shares, and in the case that the stock dividend resulted in a shareholder becoming entitled to receive less than 0.5 of a Common Share, an adjustment was made to round down to the next number of whole Common Shares;

"**Tax Act**" means the *Income Tax Act* (Canada) R.S.C. 1985, c.1 (5th Supp.), as amended;

"**TSX**" means the Toronto Stock Exchange;

"**United States**" or "**U.S.**" means the United States of America;

"**Vaquero**" means Vaquero Energy Ltd., a corporation incorporated pursuant to the ABCA;

"**Vaquero Arrangement**" means the plan of arrangement under the ABCA involving Highpine, Vaquero and the securityholders of Vaquero completed on May 31, 2005, as more particularly described under "General Development of the Business – Significant Acquisitions and Recent Developments";

"**Violet Grove Battery**" means the sour processing battery located at 16-29-48-9 W5M, which is approximately 20 kilometres west of Drayton Valley, Alberta;

"**White Fire**" means White Fire Energy Ltd., a corporation incorporated pursuant to the ABCA;

"**White Fire Arrangement**" means the plan of arrangement under the ABCA involving Highpine, White Fire and the shareholders of White Fire completed on February 21, 2006, as more particularly described under "General Development of the Business – Significant Acquisitions and Recent Developments"; and

"**White Fire Paddock Report**" means the March 3, 2006 report prepared by Paddock, evaluating the crude oil, natural gas and NGL reserves of White Fire, as at December 31, 2005, in accordance with the standards contained in the COGE Handbook and the reserves definitions set out by the Canadian Securities Administrators in NI 51-101 and the COGE Handbook.

ABBREVIATIONS

Crude Oil and Natural Gas Liquids		Natural Gas	
bbl	one barrel	mcf	one thousand cubic feet
bbls	barrels	mmcf	one million cubic feet
bbls/d	barrels per day	bcf	one billion cubic feet
mbbls	thousand barrels		
boe	barrels of oil equivalent of natural gas on the basis of 1 boe for 6 mcf of natural gas (unless otherwise indicated)	mcf/d	one thousand cubic feet per day
mboe	one thousand barrels of oil equivalent	mmcf/d	one million cubic feet per day
mmboe	one million barrels of oil equivalent	GJ	gigajoule
boe/d	barrels of oil equivalent per day	GJs/d	gigajoules per day
NGL	natural gas liquids	btu	British thermal unit
stb	standard stock tank barrel	mmbtu	million British thermal units

Boes may be misleading, particularly if used in isolation. A boe conversion ratio of six mcf to one bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. This conversion factor is an industry accepted norm and is not based on either energy content or current prices.

Other

WTI	means West Texas Intermediate.
°API	means the measure of the density or gravity of liquid petroleum products derived from a specific gravity.
psi	means pounds per square inch.

CONVERSION

The following table sets forth certain standard conversions between Standard Imperial Units and the International System of Units (or metric units).

To Convert From	To	Multiply By
mcf	thousand cubic metres ("10^3m^3")	0.0282
thousand cubic metres	mcf	35.494
bbls	cubic metres ("m^3")	0.159
cubic metres	bbls	6.290
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.471

SCHEDULE A
REPORT ON RESERVES DATA BY PADDOCK LINDSTROM & ASSOCIATES LTD.
IN ACCORDANCE WITH FORM 51-101F2

To the Board of Directors of Highpine Oil & Gas Limited (the "Corporation"):

1. We have prepared an evaluation of the Corporation's Reserves Data as at December 31, 2005. The Reserves Data consist of the following:

   (a) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2005 using forecast prices and costs; and

   (ii) the related estimated future net revenue; and

   (b) (i) proved oil and gas reserves estimated as at December 31, 2005, using constant prices and costs; and

   (ii) the related estimated future net revenue.

2. The Reserves Data are the responsibility of the Corporation's management. Our responsibility is to express an opinion on the Reserves Data based on our evaluation.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "**COGE Handbook**") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the Reserves Data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions in the COGE Handbook.

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the Reserves Data of the Corporation evaluated by us for the year ended December 31, 2005, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Corporation's Board of Directors:

Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue ($ thousands - before income taxes, 10% discount rate)			
			Audited ($)	Evaluated ($)	Reviewed ($)	Total ($)
Paddock	Evaluation of the P&NG Reserves of Highpine Oil & Gas Limited, as of December 31, 2005 prepared March 3, 2006	Canada	0	581,657	0	581,657

5. In our opinion, the Reserves Data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook.

6. We have no responsibility to update this evaluation for events and circumstances occurring after its preparation date.

7. Because the Reserves Data are based on judgments regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

Paddock Lindstrom & Associates Ltd.
Calgary, Alberta
March 27, 2006

(Signed) Dennis L. Paddock, P. Eng.
Vice President

SCHEDULE B
REPORT OF HIGHPINE MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE IN ACCORDANCE WITH FORM 51-101F3

Management of Highpine Oil & Gas Limited (the "Corporation") are responsible for the preparation and disclosure of information with respect to the Corporation's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which consist of the following:

(a) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2005 using forecast prices and costs; and

(ii) the related estimated future net revenue; and

(b) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2005 using constant prices and costs; and

(ii) the related estimated future net revenue.

An independent qualified reserves evaluator has evaluated the Corporation's reserves data. The report of the independent qualified reserves evaluator will be filed with securities regulatory authorities concurrently with this report.

The Board of Directors of the Corporation has

(a) reviewed the Corporation's procedures for providing information to the independent qualified reserves evaluator;

(b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and

(c) reviewed the reserves data with management and the independent qualified reserves evaluator.

The Board of Directors of the Corporation has reviewed the Corporation's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The Board of Directors has approved

(d) the content and filing with securities regulatory authorities of the reserves data and other oil and gas information;

(e) the filing of the report of the independent qualified reserves evaluator on the reserves data; and

(f) the content and filing of this report.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

(Signed) A. Gordon Stollery
Chairman and Chief Executive Officer

(Signed) Greg N. Baum
President and Chief Operating Officer

(Signed) Richard G. Carl
Director

(Signed) Andrew Krusen
Director

March 27, 2006

File No. 82-34869

HIGHPINE
OIL & GAS LIMITED

A Story of Growth

ANNUAL REPORT 2005

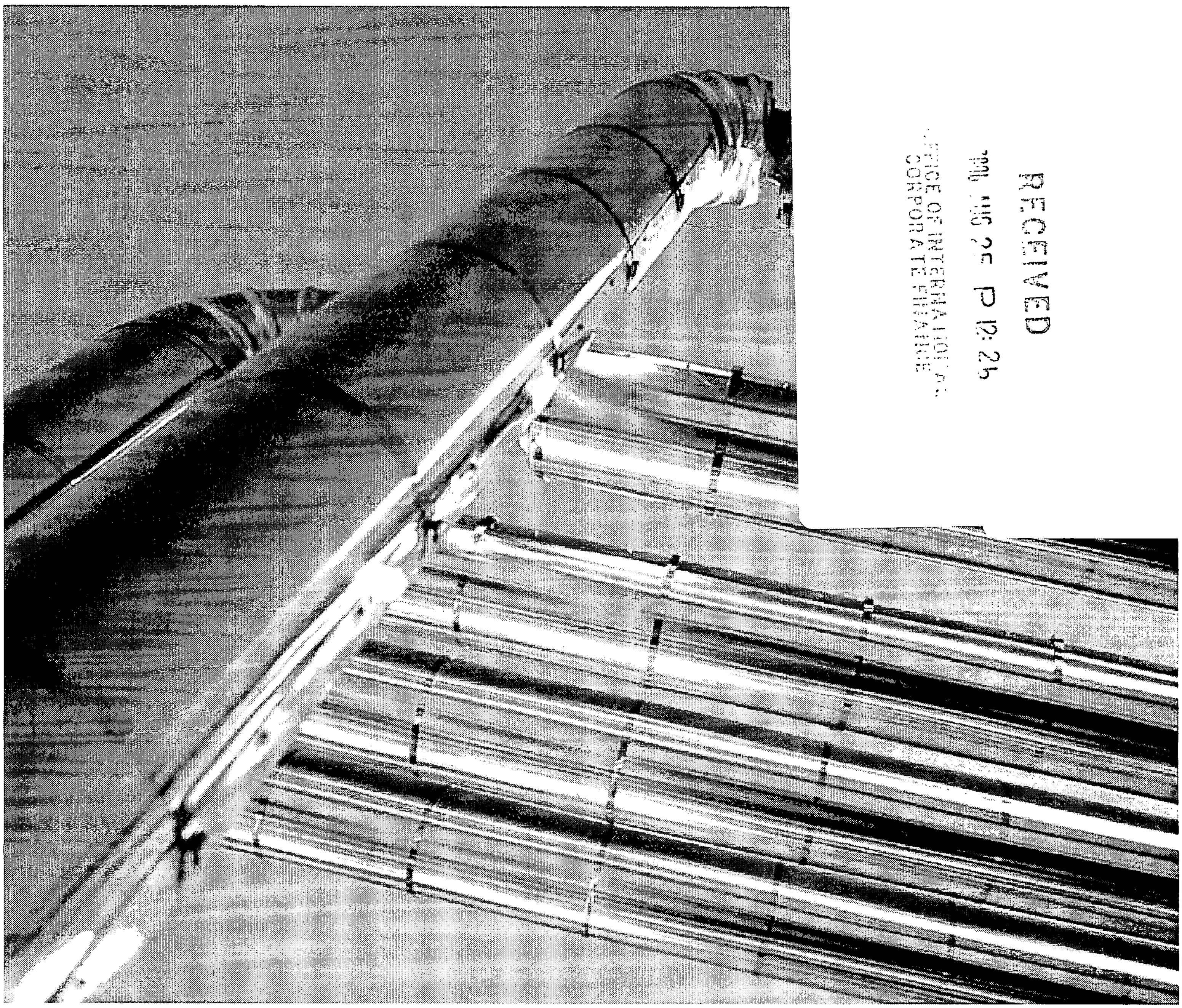


TABLE OF CONTENTS

Highpine Oil & Gas Limited (HPX) is a TSX listed, public oil and gas company, engaged in exploration and development of crude oil and natural gas in western Canada. Highpine's business strategy is to create "true" shareholder value by focusing and executing on full-cycle exploration while pursuing complementary strategic acquisitions and demonstrating financial responsibility.

ANNUAL GENERAL MEETING

Shareholders are invited to attend the annual meeting of shareholders scheduled to be held at 9:30 am on Wednesday, May 10, 2006 at the Metropolitan Conference Centre 333 - 4th Avenue S.W. Calgary, Alberta.

A STORY OF

GROWTH

PERFORMANCE

Cash flow increased 277% to $74.6 million from $19.8 million in 2004; cash flow per diluted share increased 80% to $2.09 from $1.16 in 2004.

Production increased 137% to 6,288 boe/d from 2,648 boe/d in 2004, with 2005 year-end exit rate production of approximately 11,800 boe/d and current production of approximately 13,000 boe/d.

Proved plus probable reserves increased 100% in 2005 to 24.36 mmboe.

PEOPLE

Highpine added four new members to the senior management team and assembled a full complement of professional staff to ensure the execution of the Company's business plan.

PROSPECTS

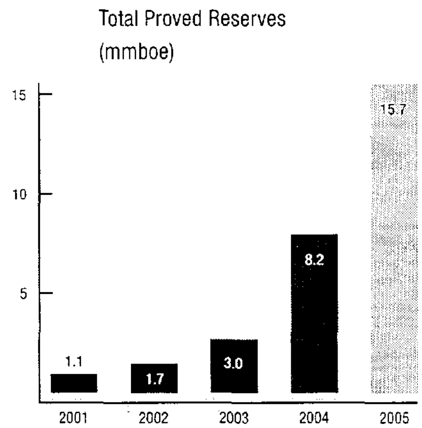
Net undeveloped land holdings increased 132% to 210,000 net acres from 90,600 net acres in 2004.

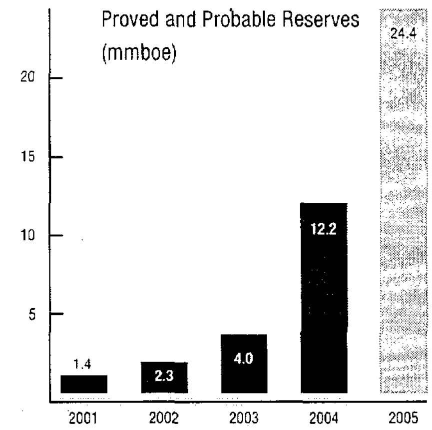
176 drilling locations, including 110 locations in Pembina.

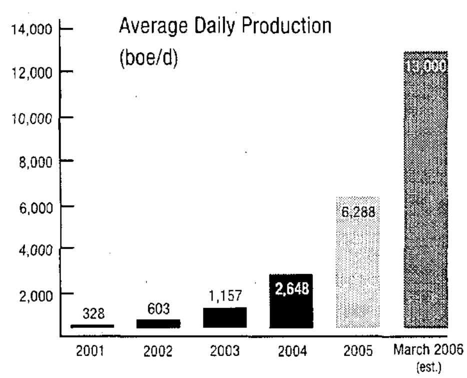
HIGHLIGHTS

(000s except per share data and $/boe amounts)	2005	2004	% Change
Financial			
Total revenue[1]	143,644	42,051	242
Cash flow from operations	74,550	19,773	277
Per share – diluted	2.09	1.16	80
Net earnings	12,274	3,177	286
Per share – diluted	0.34	0.19	79
Net debt [2]	109,599	49,637	121
Total assets	753,690	163,388	361
Corporate acquisitions[3]	257,314	51,151	403
Capital expenditures[4]	153,606	61,133	151
Total shares outstanding	44,250	19,779	124
Weighted average shares outstanding[5]			
Basic	35,051	16,747	109
Diluted	35,718	17,036	110
Operating			
Average daily production			
Crude oil and NGLs (bbl/d)	3,984	1,578	152
Natural gas (mcf/d)	13,823	6,423	115
Total (boe/d)	6,288	2,648	137
Average selling prices[6]			
Crude oil and NGLs ($/bbl)	67.16	47.61	41
Natural gas ($/mcf)	9.84	6.91	42
Total ($/boe)	64.18	45.13	42
Wells drilled – Gross (net)			
Oil	9 (6.5)	13 (6.6)	-
Gas	19 (11.0)	25 (10.0)	-
Abandoned / other	28 (18.9)	16 (6.1)	-
Total	56 (36.4)	54 (22.7)	-
Drilling success rate (%)	63	80	-
Operating Netback ($/boe)			
Oil and gas sales	64.18	45.13	42
Processing revenues	0.88	1.06	(17)
Royalties	(16.99)	(10.46)	62
Operating costs	(7.06)	(6.56)	8
Transportation costs	(1.23)	(0.62)	98
Realized hedging loss	(2.88)	(2.80)	3
Operating Netback	36.90	25.75	43

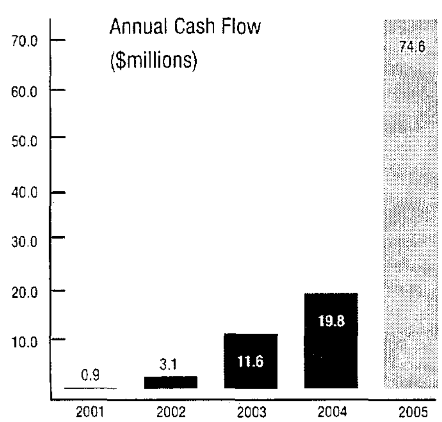
1) Total revenue is after realized and unrealized hedging losses and gains and includes processing revenues.
2) Net debt includes working capital excluding unrealized financial instruments.
3) *Corporate acquisition only includes the amount allocated to property, plant and equipment.*
4) Capital expenditures are presented net of proceeds of disposals.
5) Weighted average shares outstanding at December 31, 2004 have been restated to give effect to the February 15, 2005 stock dividend.
6) The average selling prices reported are before hedging loss.

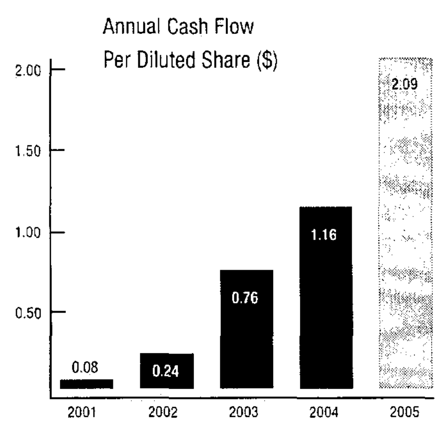

Total Proved Reserves
(mmboe)
15
10
5
1.1
1.7
3.0
8.2
15.7
2001
2002
2003
2004
2005


Proved and Probable Reserves
(mmboe)
20
15
10
5
1.4
2.3
4.0
12.2
24.4
2001
2002
2003
2004
2005

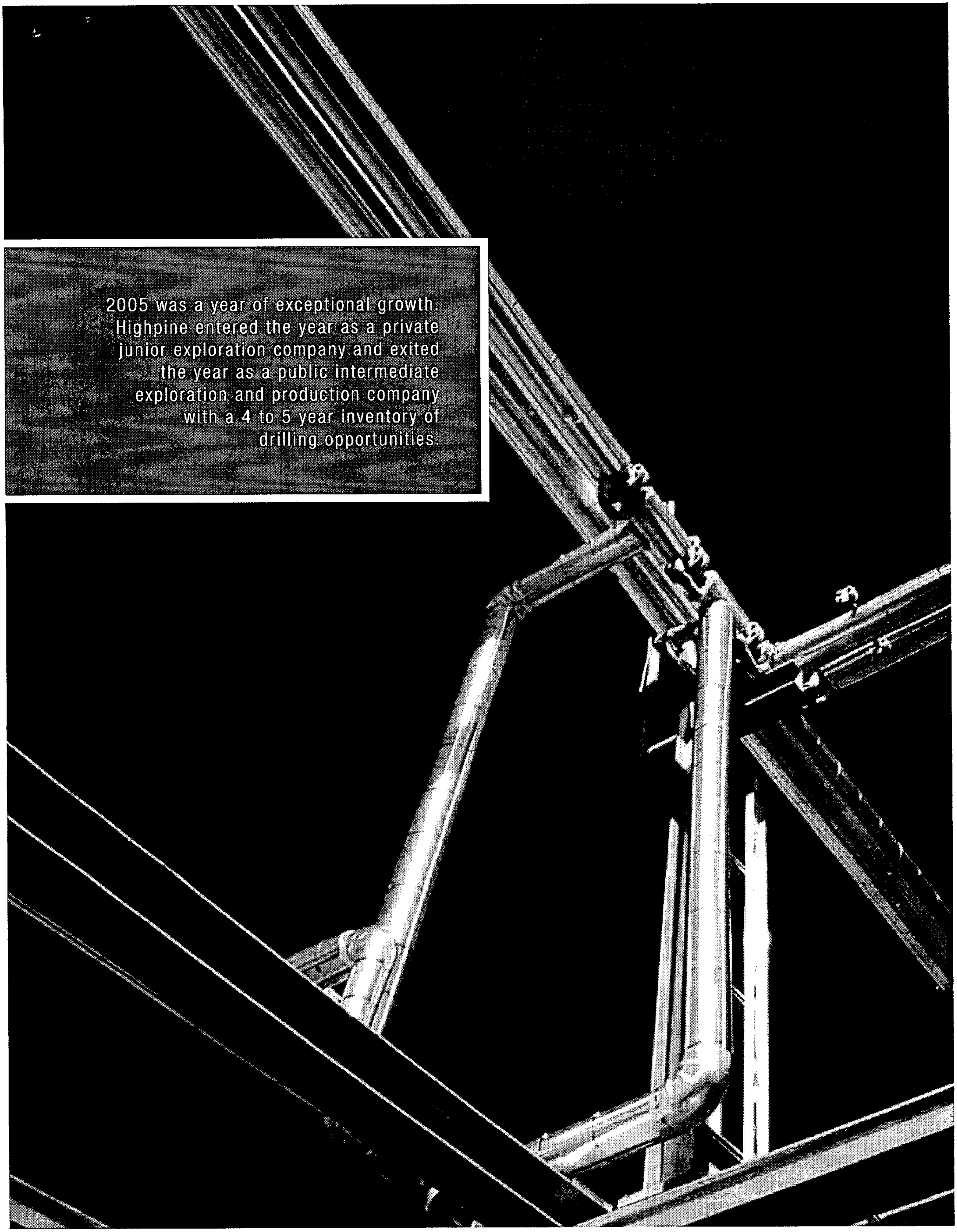

Average Daily Production
(boe/d)
14,000
12,000
10,000
8,000
6,000
4,000
2,000
328
603
1,157
2,648
6,288
13,000
2001
2002
2003
2004
2005
March 2006
(est.)

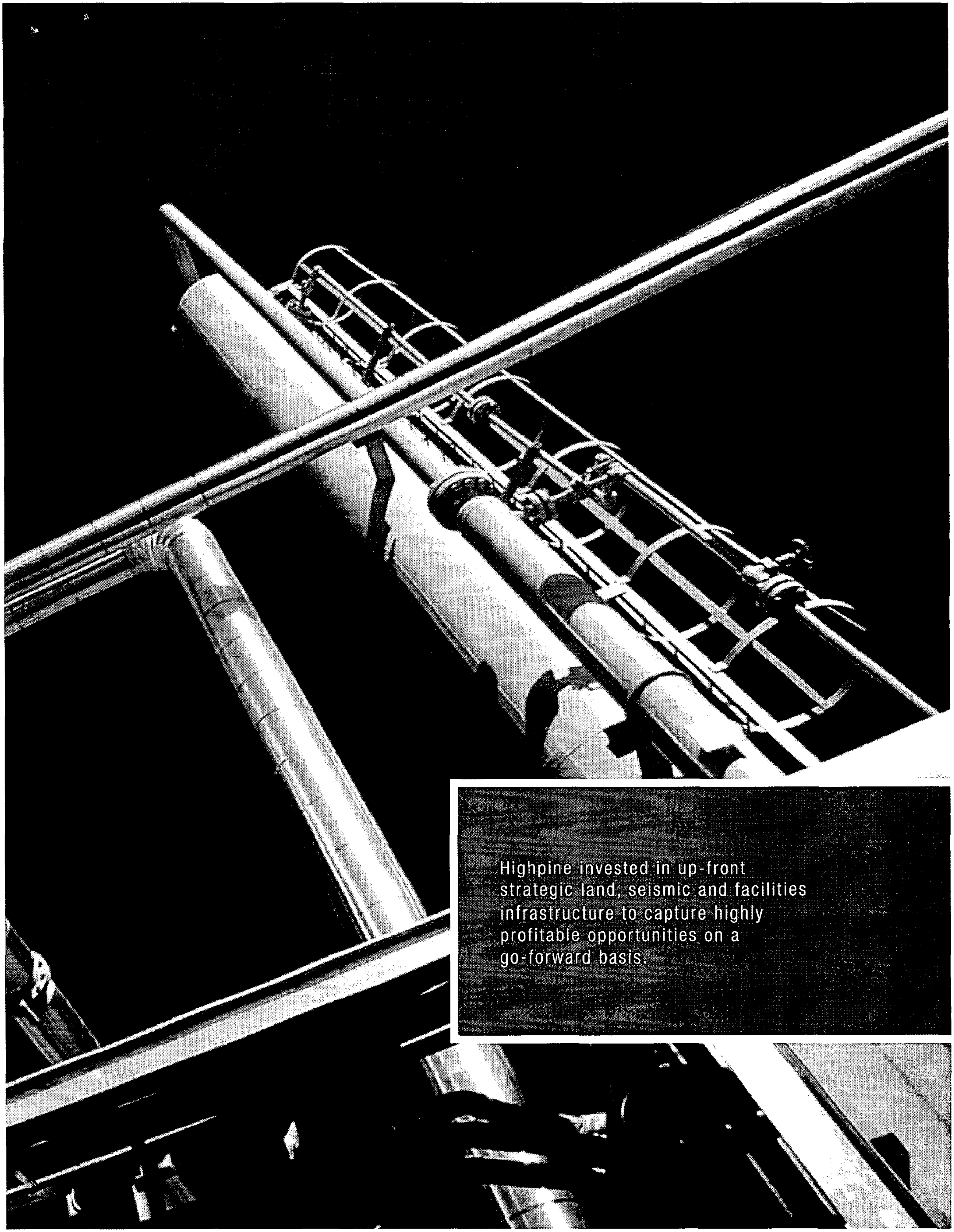
GROWTH


Annual Cash Flow
($millions)
70.0
60.0
50.0
40.0
30.0
20.0
10.0
0.9
3.1
11.6
19.8
74.6
2001
2002
2003
2004
2005


Annual Cash Flow
Per Diluted Share ($)
2.00
1.50
1.00
0.50
0.08
0.24
0.76
1.16
2.09
2001
2002
2003
2004
2005

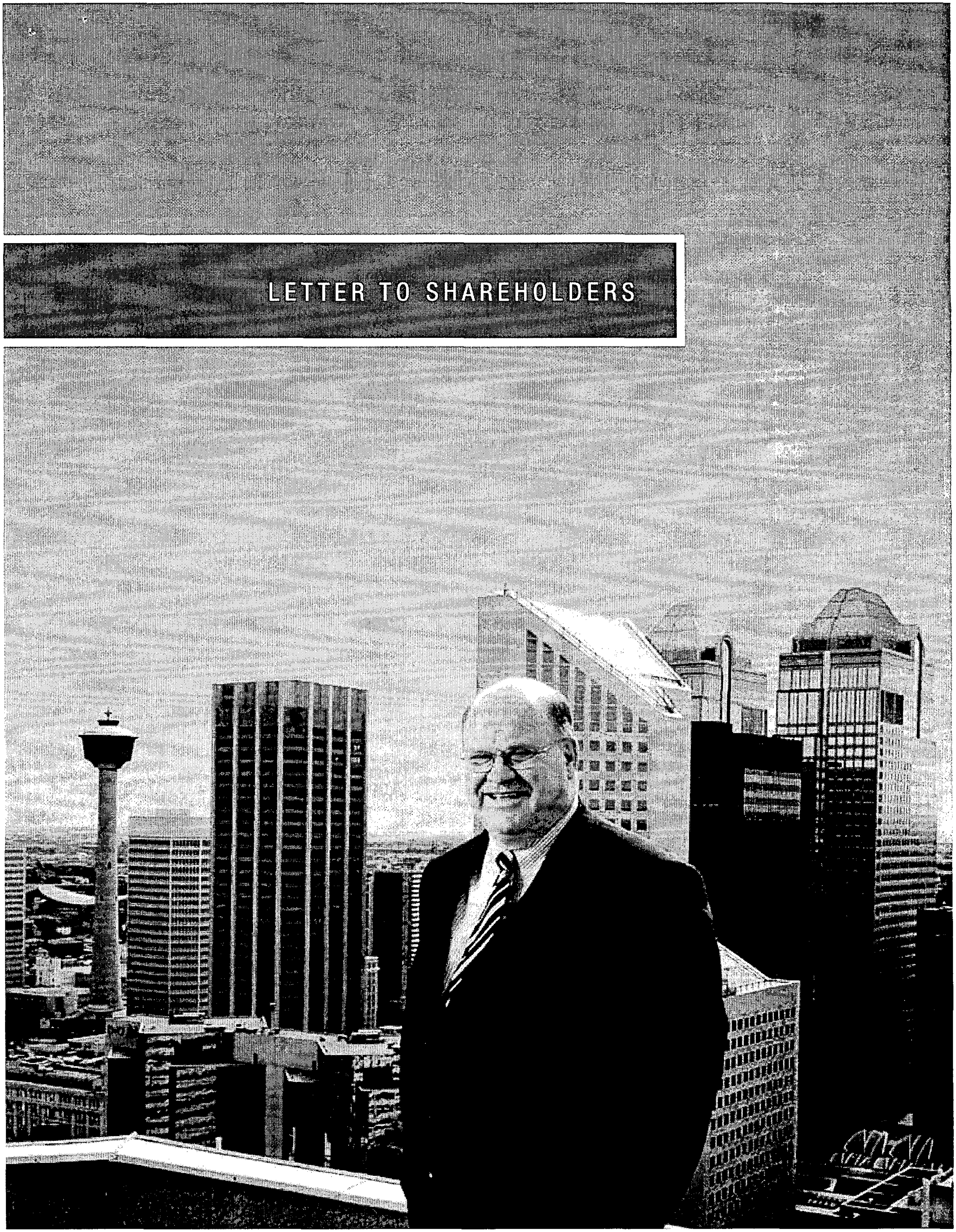
2005 was a year of exceptional growth. Highpine entered the year as a private junior exploration company and exited the year as a public intermediate exploration and production company with a 4 to 5 year inventory of drilling opportunities.





Highpine invested in up-front strategic land, seismic and facilities infrastructure to capture highly profitable opportunities on a go-forward basis.

LETTER TO SHAREHOLDERS



2005 was a year of exceptional growth and change.

We started the year as a private oil and gas exploration company with a dominant competitive position in one of Western Canada's most exciting light oil plays. We completed the year as a Toronto Stock Exchange listed public company with a market capitalization exceeding one billion dollars with production rising past 12,000 barrels per day of oil equivalent (boe/d). During the year, our position in the exciting West Pembina Nisku play has been enhanced and extended providing Highpine with five years of prolific drilling opportunities.

Major transactions that we completed or initiated in 2005 are as follows:

- Achieved a successful Initial Public Offering of the Company's shares in April;
- Effected a $400 million dollar share-for-share merger with Vaquero Energy Ltd. in May;
- Signed a $100 million dollar share-for-share merger with White Fire Energy Ltd. in December, which subsequently closed on February 21, 2006; and
- After yearend, completed a successful offering of $100 million of equity in February, 2006.

Major operating and capital achievements in 2005 were as follows:

- Constructed, commissioned and started-up our 80% owned, 15,000 bbls/day Violet Grove crude oil and sour natural gas processing facility;
- Started-up a 100% owned 10 mmcf/d natural gas processing facility at Joffre;
- Drilled 56 wells with an average working interest of 65%;
- Increased our full-time employee base from 16 at the beginning of the year, to 50 by yearend; and
- Consolidated our operations in new office space in the Petro Canada Centre in Calgary.

Major financial results accomplished during 2005 were:

- Average barrels of crude oil equivalent rose to 6,288 up 137% from the previous year;
- Cash flow was $74.6 million ($2.09 per diluted share) compared to $19.8 million ($1.16 per diluted share) in 2004;
- Earnings were $12.3 million ($0.34 per diluted share) compared to $3.2 million ($0.19 per diluted share) in the previous year; and
- Yearend crude oil and natural gas reserves doubled from the previous year to 24.4 million boes.

We also have to admit that not everything went our way in 2005. We did have a number of unexpected setbacks. The most financially damaging was a series of start-up problems at our Violet Grove processing facility which prevented optimal production from occurring until mid December. These are now behind us and the facility is running smoothly. We also ran into a roadblock in the well licensing process with the result that our West Pembina drilling program was basically halted for much of the year. This too has improved with several well licences expected to be awarded to Highpine in 2006.

Today, Highpine enjoys a focused asset base, comprised of two main fairways; West Pembina where we target primarily light oil and an adjacent diagonal West Central Alberta Fairway targeting primarily high energy "sweet" natural gas. About 90% of our production comes from these two fairways. The excellent economics of these fairways is reflected in our 2005 financial results, displaying operating netbacks before hedges of near $40 per boe and low operating costs net of processing revenues of $6.18 per boe. A substantial portion of our 2005 capital program was invested for the future in land, seismic and facility infrastructure. As a result, we have a multi-year inventory of attractive exploration and development targets from which we can continue to build Highpine. With current production averaging approximately 13,000 boes and growing, we have the cash flow, the balance sheet and the personnel to take the Company to the next level.

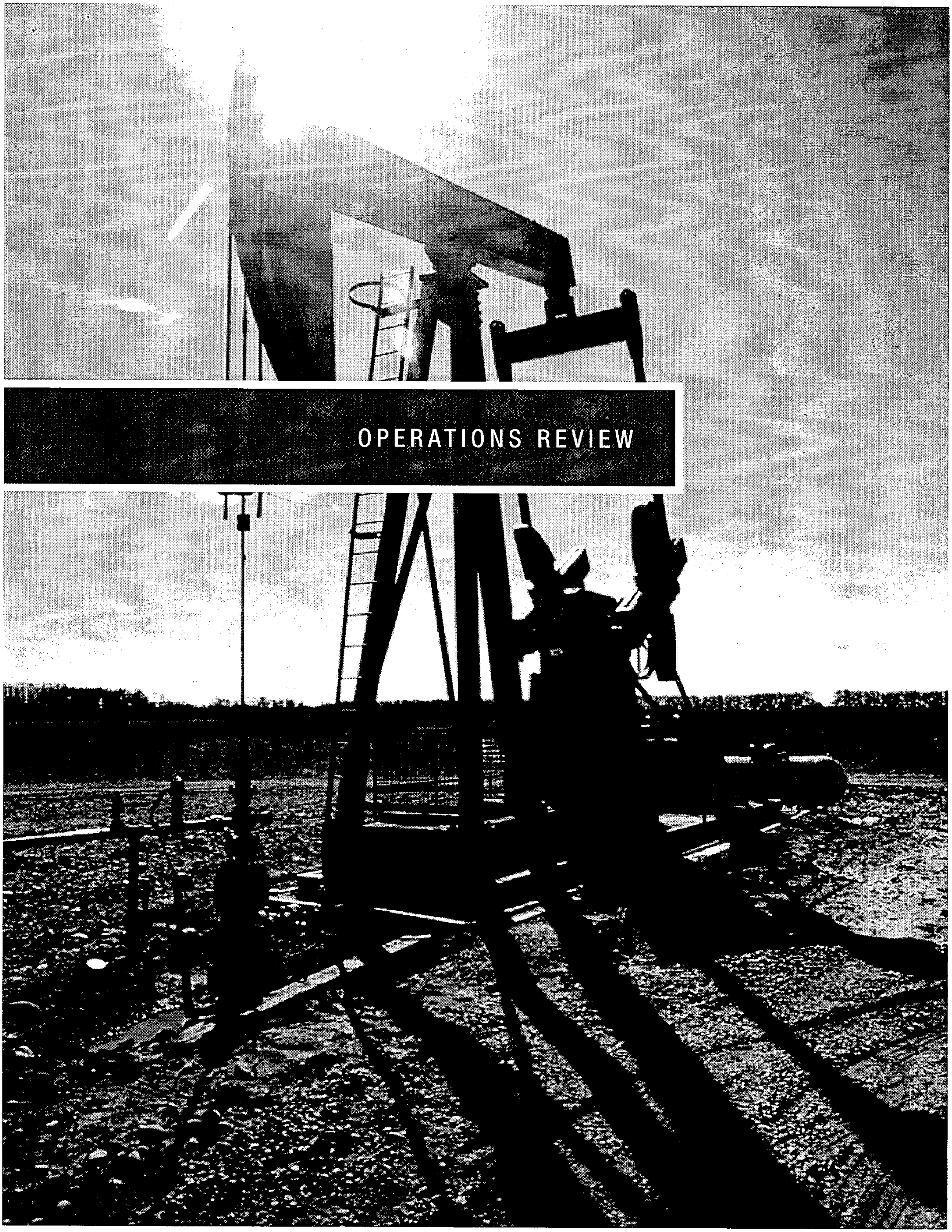
Building a business, especially from the beginning, takes dedicated, hard-working, creative and talented people. I want to take this opportunity to mention three of our very first employees; Corelie Cormier, Doug McArthur and Greg Baum. Corelie has been a great cheerleader and organizer from day one. She has been promoted to look after the investor relations. At the Directors' meeting held on March 7, 2006, the Directors promoted Greg Baum to President and Chief Operating Officer of the Company and Doug McArthur to Senior Vice President, Exploration. Highpine has only made it this far as a result of their Herculean efforts. I will continue as Chairman and Chief Executive Officer.

We would like to thank all of our employees, both old and new, for their special efforts this year. It was an exciting, eventful and stressful year. Our Directors were a continuous source of strength and support. Thank you. To our shareholders, thank you for your patience. We look forward to 2006. Many of our 2005 challenges have been resolved. We hope to continue the strong production and financial growth in 2006.

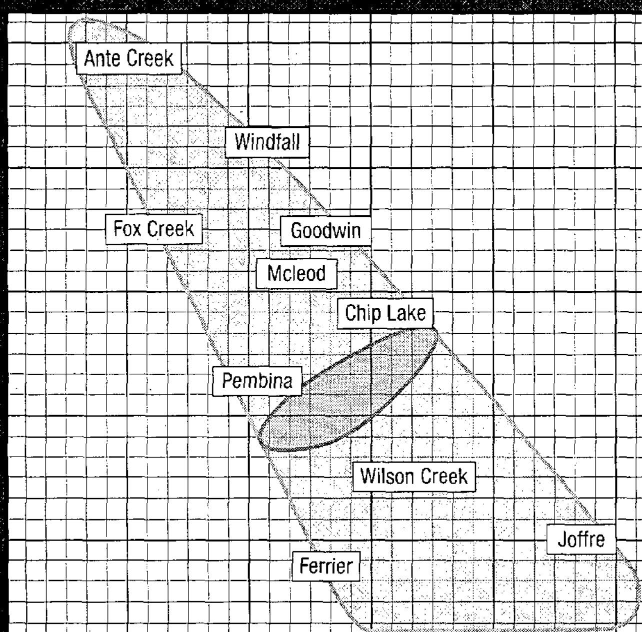
Yours very truly,

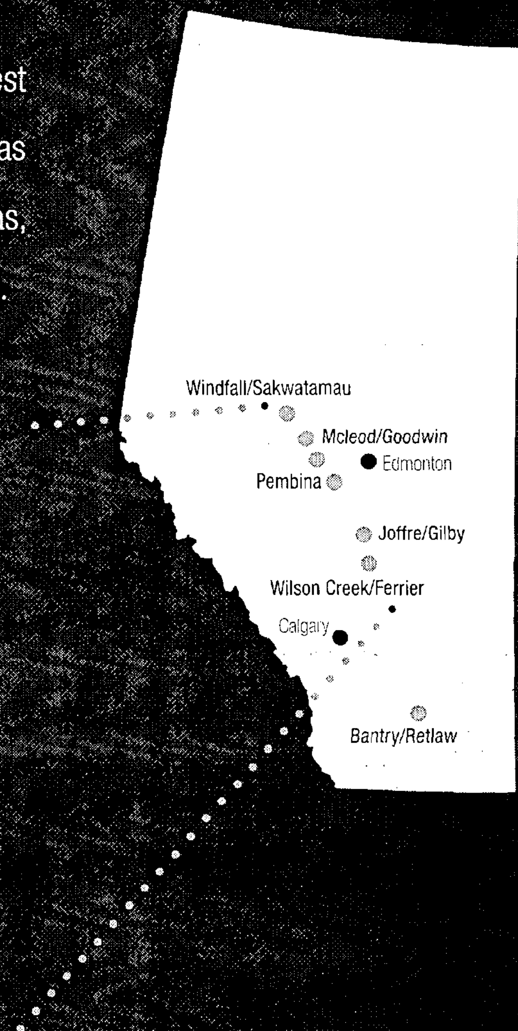
A. Gordon Stollery
Chairman & Chief Executive Officer

OPERATIONS REVIEW



Highpine focuses its activities in the prolific West Pembina Nisku trend and the West Central Alberta Gas Fairway, targeting high quality light oil, natural gas, and natural gas liquid reserves in Western Canada.





PEMBINA

Current production

- approximately 10,000 boe/d
- 18 Nisku Pools

Current drilling inventory

- 90 firm Nisku locations
- 20 contingent locations

Facilities

- 80% ownership in Violet Grove oil battery
- 65% ownership in Easyford oil battery
- 16% in Dominion Violet Grove oil battery
- 36% ownership in Keyera Brazeau North Pipeline

WEST CENTRAL ALBERTA GAS FAIRWAY

Current production

- approximately 2,400 boe/d

Current drilling inventory

- 60 locations

Facilities

- Joffre – 100% owned 10 mmcf/d Gas Plant
- Mcleod/Goodwin – 27.5% ownership in 15 mmcf/d Mahaska Gas Plant
- Chip Lake – 62.5% ownership in oil battery
- Wilson Creek – 50% ownership in oil battery and gas handling facility
- Karr – 50% ownership in oil and gas handling facility

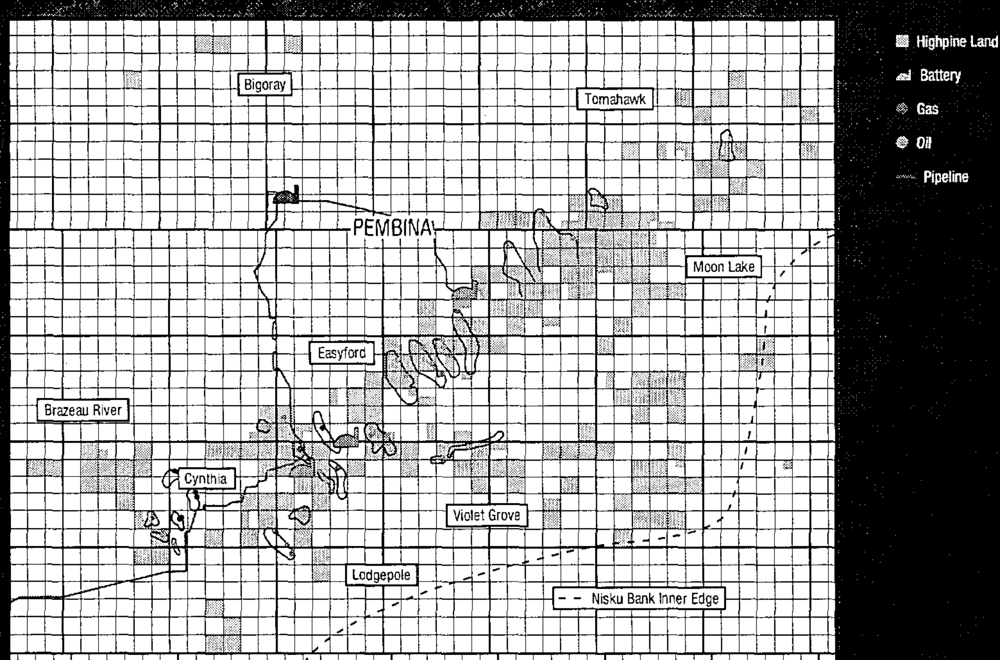
Pembina

Pembina is located in the Drayton Valley area of Alberta, approximately 100 kilometres southwest of Edmonton. The primary production target in Pembina is light oil (± 40° API) from the Devonian Nisku formation, where successful wells can exhibit production rates in excess of 1,000 bbls/d and recover greater than one million barrels of oil.

Pembina is Highpine's most significant core property, representing the majority of Highpine's total production volumes and future growth opportunities. Highpine has an inventory of exploration and development drilling opportunities in Pembina that could provide several years of future growth potential. Overall working interest production from the area averaged 3,927 boe/d in 2005, representing 62% of the Company's total production. In early March 2006, Pembina reached production levels in excess of 10,000 boe/d, representing over 80% of our production volumes which were an estimated 13,000 boe/d.

In March 2005, Highpine drilled its biggest discovery at 9-35-48-8 W5M (100% owned) which encountered over 26 metres of oil pay and has been producing at rates in excess of 2,000 boe/d.

Highpine's dominant land position in Pembina is expected to provide 4 to 5 years of future drilling opportunities.



Highpine commenced activities in Pembina in November 2002 when the Company participated in the 9-30-49-8 W5M Nisku discovery. Recognizing the significant potential of the trend, Highpine became very aggressive in acquiring land holdings in the now named "Pembina Nisku Fairway". At year-end 2005, Highpine had interests in approximately 112,000 undeveloped gross acres (87,500 net) in this fairway, with an average 78% working interest in the lands. Highpine participated in several additional Nisku oil discoveries from 2003 to 2005 including the Nisku II pool, the largest field found thus far. In March 2005, Highpine drilled its biggest discovery at 9-35-48-8 W5M (100% owned) which encountered over 26 metres of oil pay and has been producing at rates in excess of 2,000 boe/d. To date, Highpine has ownership in 18 Nisku discoveries in the Fairway.

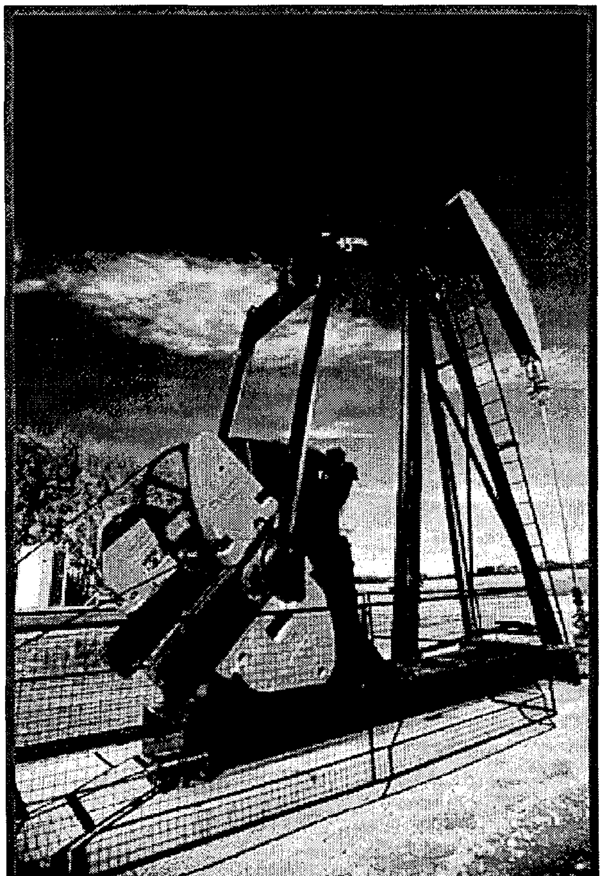
The Pembina Nisku play is very competitive because of the prolific nature of the successful wells; however, because the Nisku oil is "sour", longer lead time is required to obtain drilling licenses to drill the wells and construction permits to build the facilities required to process and transport the fluids. Highpine's strategy was to obtain as much control and infrastructure ownership as possible in order to exploit our Pembina lands in the most optimum and timely manner. Following through on this strategy, Highpine participated in the construction and acquisition of the critical infrastructure necessary to handle the Nisku production. At year-end 2005, Highpine owned significant working interests in three oil handling facilities, including the Highpine constructed and operated Violet Grove Battery. On a combined basis the Company has oil handling capability in excess of 20,000 bbls/d. Highpine also participated in the construction of the Keyera operated Brazeau North Gas Pipeline which transports the sour gas from the batteries to a major gas processing facility. Highpine further enhanced control of the play by consolidating three companies who were actively pursuing the Nisku. In 2004, Highpine acquired 50% of Rubicon Energy Corporation, and in 2005, shortly after going public, we acquired Vaquero Energy Ltd. On February 21, 2006 Highpine closed the merger of White Fire Energy Ltd. Highpine is clearly the dominant player in this exciting trend.

The December 31, 2005 Paddock Lindstrom & Associates Reserve Report ("Paddock") attributes 17.4 million boes of proved plus probable reserves to the Pembina area. This represents approximately 71% of Highpine's total corporate reserves.

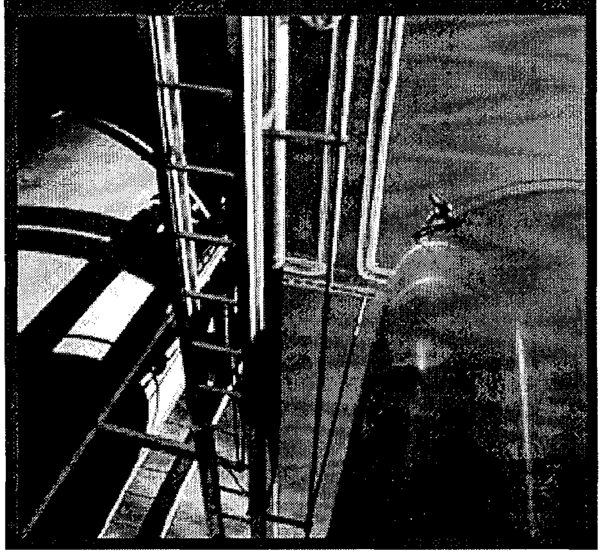
For 2006 and several years thereafter, Pembina is anticipated to provide the majority of organic growth for Highpine. Highpine has an inventory of 90 firm geologically and geophysically evaluated drilling locations on lands it owns. Approximately 15 to 20 gross Pembina Nisku wells are planned for drilling in 2006. Additional land and seismic acquisition programs are ongoing including a major 3D seismic program which is currently underway, and is expected to add additional drilling locations to our inventory.

Secondary producing horizons include natural gas (with liquids) from the Glauconite, Rock Creek, Ellerslie and Pekisko zones. The area has year-round access, which enables Highpine to conduct its exploration and development activities almost continuously.

3D seismic programs and interpretation are fundamental to the success in Pembina Nisku



Given the multi-zoned potential, success rates normally exceed 50% in finding economic reserves



West Central Alberta Gas Fairway

The West Central Alberta Gas Fairway is located northwest of Edmonton, Alberta and trends approximately 200 miles southeast towards Red Deer. It includes natural gas properties in Joffre, Chip Lake, Windfall/Sakwatamau, McLeod/Goodwin, Ante Creek and Wilson Creek/Ferrier.

The Fairway can generally be described as a "sweet" and "high energy" natural gas with associated NGL's play. "Sweet" means the majority of the producing zones do not contain Hydrogen Sulphide (H_2S) and can be licensed, drilled and brought on stream fairly routinely. "High energy" means that the heating value of the gas attracts a premium price above industry standard natural gas price indicators. The combined effect of premium pricing and natural gas liquids generates some of the highest netbacks realized from oil and gas properties in Western Canada.

Drilling in the Fairway offers medium risk, medium depth and multi-zone opportunities to find economic natural gas discoveries. On most of Highpine's lands, there is year-round access. Wells drilled target natural gas in the Edmonton, Gething, Notikewan, Rock Creek, Nordegg, Belly River, Viking, Glauconite, Ellerslie, Pekisko and Wabamun zones. Given the multi-zoned potential, success rates normally exceed 50% in terms of finding economic reserves. Wells can typically produce one to two million cubic feet per day of natural gas and recoveries can be in the order of one to two billion cubic feet of natural gas per well. Some wells are able to come on stream at rates in excess of five million cubic feet per day and recover several billion cubic feet or more of reserves. In the southeast portion of the Gas Fairway, industry operators are evaluating Horseshoe Canyon and Mannville coalbed methane ("CBM") potential on various lands, including some of Highpine's. Highpine has negotiated future participation rights in these CBM opportunities, should they prove to be commercial.

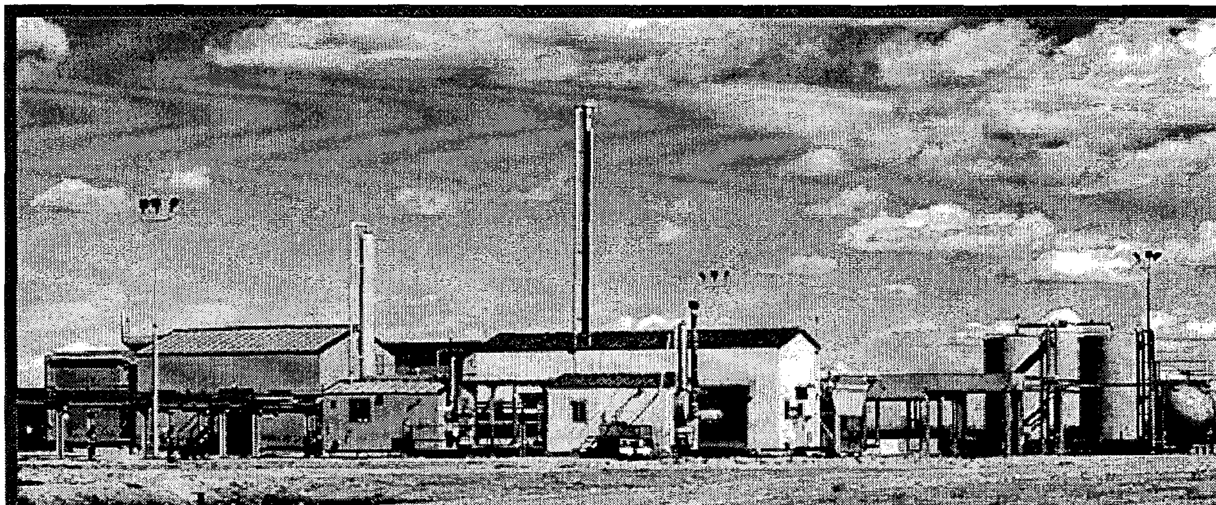
The West Central Alberta Gas Fairway is Highpine's second most significant core property, averaging approximately 1,600 boe/d in 2005, which represented 25% of the Company's total production. In March 2006 the Gas Fairway production was approximately 2,400 boe/d with several high rate, high working interest wells to be tied-in over the next several months.

Highpine owns and operates various natural gas processing facilities along the trend, and also utilizes third-party facilities to transport and process production. Given the amount of "sweet" handling infrastructure in the Fairway, placing new wells on stream can be done relatively quickly.

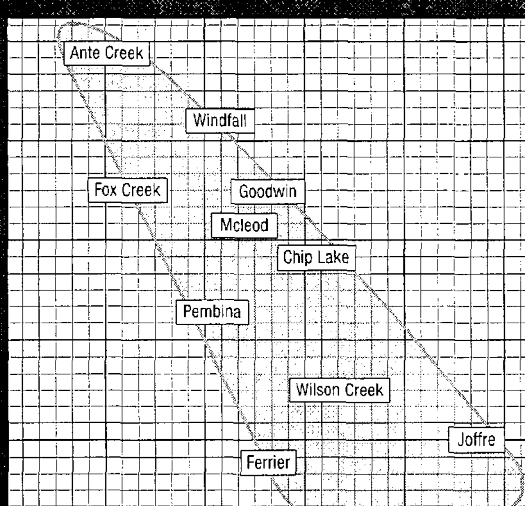
Highpine has been actively building our position in the Fairway since January 2002 when we drilled our first significant natural gas discovery at 4-16-40-27 W4M at Joffre. The Rubicon acquisition added lands in Ante Creek where two significant natural gas discoveries were made in 2005. Based on previous success, significant land and seismic acquisition programs are underway. In 2005, natural gas discoveries were also drilled in Windfall/ Sakwatamau and Mcleod/Goodwin, with follow-up opportunities identified for 2006. The addition of the White Fire assets, particularly the Wilson Creek, Ferrier, Fox Creek and Karr properties, increases our inventory of Fairway drilling locations to 60.

Paddock attributed 5.4 million boes of proven plus probable reserves to Highpine's West Central Alberta Gas Fairway, representing approximately 22% of Highpine's total corporate reserves. With the addition of the White Fire assets, the reserves attributed to Highpine's West Central Alberta Gas Fairway will be increased.

Highpine believes in the attractive production and economic growth potential of our West Central Alberta Gas Fairway and expects to generate several years of ongoing drilling opportunities on our undeveloped land base of approximately 114,000 gross acres (87,500 net) at 2005 year-end. White Fire has added an additional 10,000 net undeveloped acres to our Fairway. We expect to participate in the drilling of a minimum of 50 wells in the Fairway in 2006. At the same time, we will replenish our drilling inventory on an ongoing basis with follow-ups to successful wells, continued geological evaluation of the trend, and future land acquisition programs.



Joffre Gas Plant



Highpine believes in the attractive production and growth potential of our West Central Alberta Gas Fairway and expects to generate several years of ongoing drilling opportunities on our undeveloped land base of approximately 114,000 gross acres (87,500 net)

Bantry/Retlaw

The Bantry/Retlaw property is located in the Brooks area of Alberta approximately 200 kilometres southeast of Calgary, Alberta. The Bantry/Retlaw property is Highpine's major southern Alberta property, which produced approximately 576 boe/d in 2005, representing approximately 9% of Highpine's total production volumes.

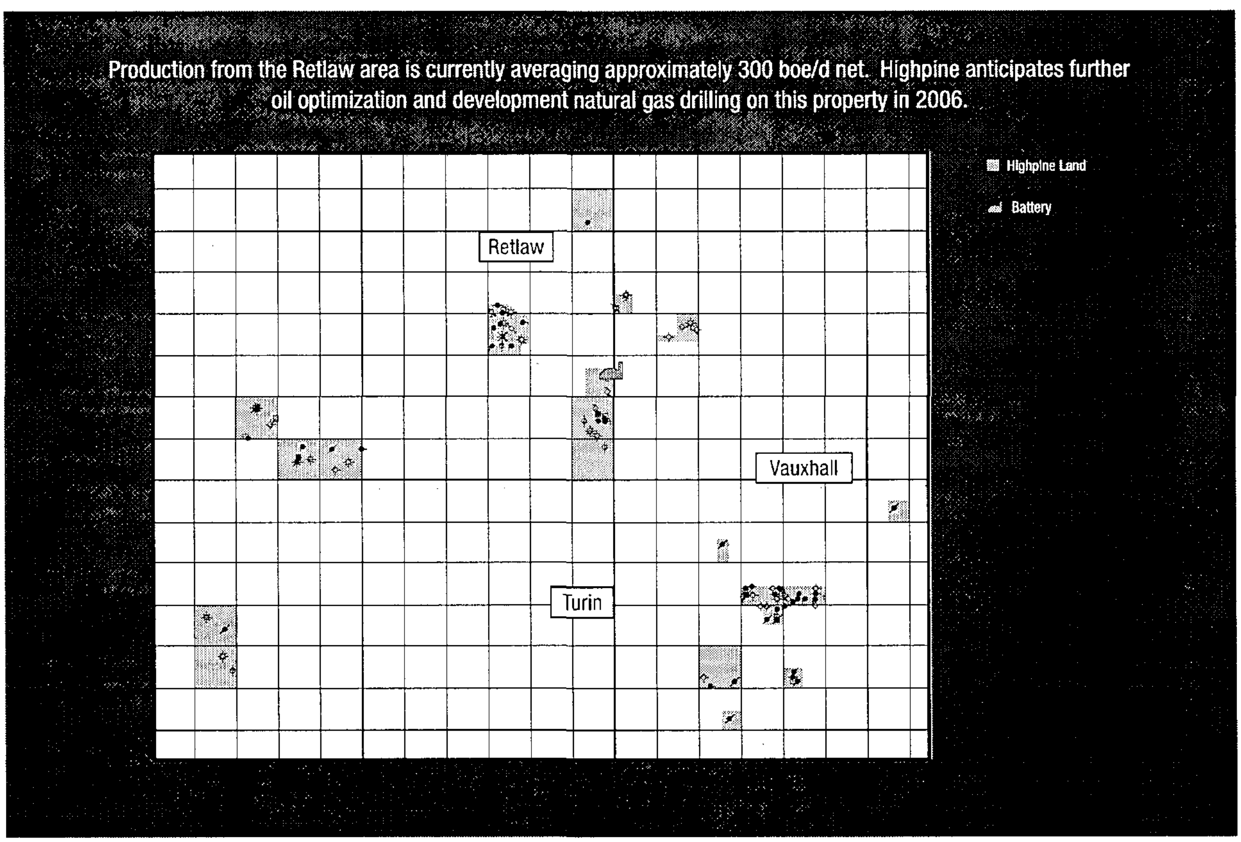
These properties can generally be described as lower risk oil and natural gas exploitation opportunities in various Mannville zones. Highpine's working interest production from the property averaged 576 boe/d in 2005, representing approximately 9% of the company's total production. In addition, Highpine has an average 53% working interest in two oil batteries. All of Highpine's production is gathered in flowlines connecting wells to central batteries. At the central batteries, produced oil, natural gas and water are separated. Water is disposed of in water disposal wells, which are either operated or partially owned by Highpine.

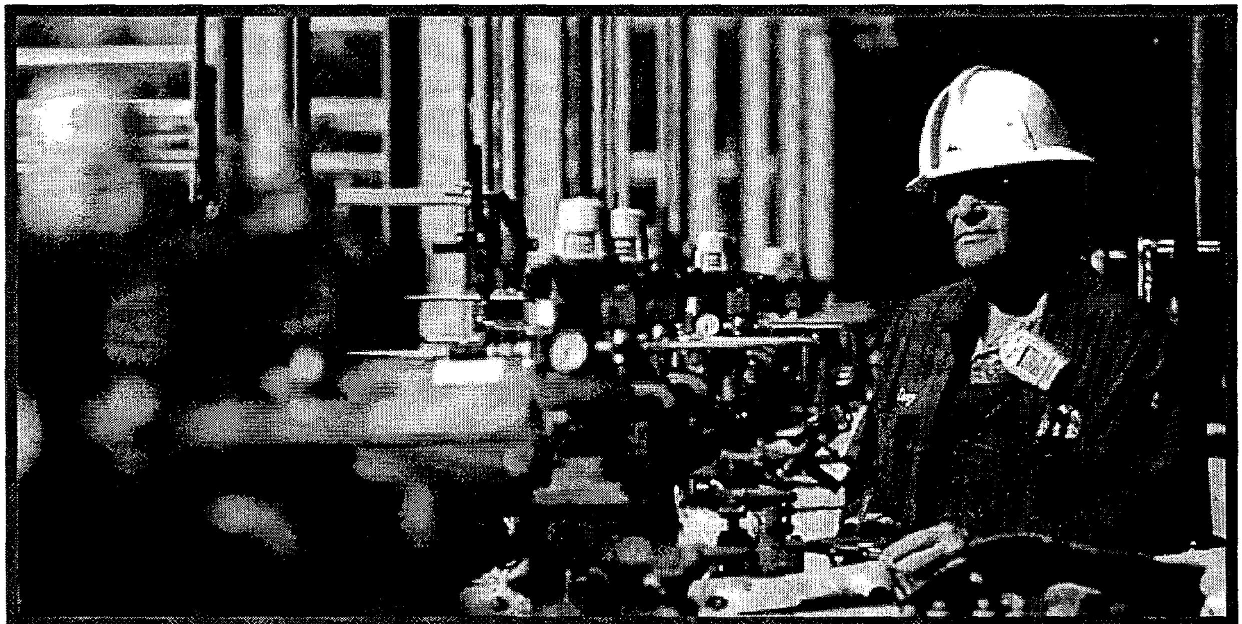
The Bantry/Retlaw property consists of 6,234 gross (1,617 net) acres of developed land and 3,700 gross (1,100 net) acres of undeveloped land.

The Paddock Report attributes proved plus probable reserves of 1.0 mmboe to Highpine's working interest in the Bantry/Retlaw area, representing 4% of Highpine's total reserves.

In May 2000, Highpine acquired a 40% working interest in an oil property at Bantry. By February 2006, the property consisted of 18 wells, producing approximately 200 net bbl/d of 25° API oil and miscellaneous associated and non-associated gas volumes. The Bantry property is characterized by long-life oil with ongoing exploitation opportunities, including uphole natural gas re-completions.

Highpine commenced activities in the Retlaw region in March 2002 when it acquired working interests in various oil properties in the area. The properties consisted of several minor working interest producing wells and a 65% working interest in a suspended 29° API Mannville oil pool. The producing wells were sold in March 2002 at a price equivalent to what was paid for the entire interest in the region. In late 2003, after a technical study was completed on the suspended pool, Highpine re-activated the old wells, drilled additional wells and installed facilities capable of bringing all of the wells on production under high volume lift. These facilities were commissioned in June 2004. Production from the Retlaw area (which is derived from the foregoing oil wells and some uphole natural gas exploitation) is currently averaging approximately 300 boe/d net. Highpine anticipates further oil optimization and development natural gas drilling on this property in 2006.





Vaquero Acquisition

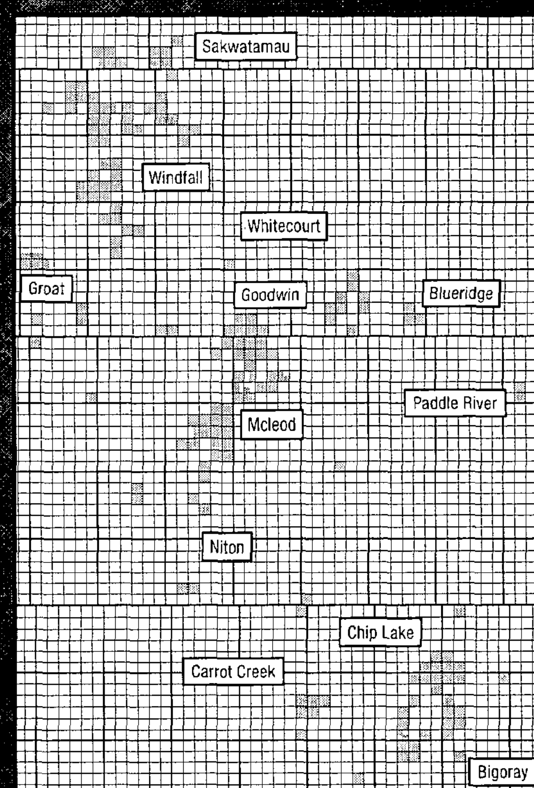
On April 6, 2005, Highpine acquired Vaquero Energy Ltd. by way of a share swap plan of arrangement. The Vaquero acquisition was very strategic to Highpine in that it strengthened Highpine's already dominant position in the prolific Pembina Nisku play, and added several quality natural gas properties (including drilling prospects) to our West Central Alberta Gas Fairway.

At the time of acquisition, the Vaquero assets were producing approximately 3,600 boe/d and included proven plus probable reserves of approximately 11 million boes of oil and natural gas, 73,600 net acres of undeveloped land and significant ownership in oil and natural gas processing facilities in Pembina and Mcleod/ Goodwin.

White Fire Acquisition

Highpine believes company consolidations in the Pembina Nisku play will allows for more efficient and timely development of the assets. On December 12, 2005, Highpine announced a share swap plan of arrangement for the acquisition of White Fire Energy Ltd. The acquisition closed on February 21, 2006. At the time of acquisition, Highpine evaluated the White Fire assets to have approximately 1,100 boe/d of production potential, approximately three million boes of proven plus probable reserves of oil and natural gas, and 33,000 net undeveloped acres of land. White Fire's assets were very complementary, not only in Pembina, but also in our West Central Alberta Gas Fairway. As a final attraction in the merger, several of White Fire's executives and senior staff joined the Highpine team, thereby strengthening Highpine's ability to execute on its business plan.

The Vaquero acquisition was very strategic to Highpine in that it strengthened Highpine's already dominant position in the prolific Pembina Nisku play, and added several quality natural gas properties (including drilling prospects) to our West Central Alberta Gas Fairway.



Reserves

As at December 31, 2005, Highpine's total proved plus probable gross working interest reserves were 24,356 mboe, an increase of 100% compared to 12,177 mboe as at December 31, 2004.

The growth in reserves volumes resulted principally from Highpine's successful 2005 drilling program and the acquisition of Vaquero.

Paddock has evaluated all of the Company's reserves as at December 31, 2005. The December 31, 2005 reserves presented below, include Company working interests before royalty interests and before royalty costs. Where volumes are expressed on a barrel of oil equivalent (boe) basis, gas volumes have been converted to barrels of oil in the ratio of one barrel of oil to six thousand cubic feet of natural gas.

SUMMARY OF CRUDE OIL, NGL AND NATURAL GAS RESERVES AND NET PRESENT VALUES OF ESTIMATED FUTURE NET REVENUE AS OF DECEMBER 31, 2005 BASED ON FORECAST PRICE ASSUMPTIONS*

	Natural Gas (bcf)	Crude Oil & NGLs (mbbls)	Total (6:1) (mboe)
Proved developed producing	22.67	9,138	12,916
Proved developed non-producing	8.76	747	2,207
Proved undeveloped	0.34	546	602
Total proved	31.77	10,431	15,725
Probable additional	15.37	6,069	8,631
Total proved plus probable	47.14	16,500	24,356

Oil & Gas Price Forecast	WTI @ Cushing $US/BBL	US/CDN Exchange Rate	AECO C C$/MMBTU
Year			
2006	60.00	0.850	10.54
2007	57.50	0.850	9.52
2008	55.00	0.850	8.32
2009	52.50	0.850	7.71
2010	50.00	0.850	7.10

RESERVES RECONCILIATION*

	Natural Gas		Crude Oil & NGLs		Combined BOE	
	Total Proved (bcf)	Proved & Probable (bcf)	Total Proved (mbbls)	Proved & Probable (mbbls)	Total Proved (mboe)	Proved & Probable (mboe)
December 31, 2004	17.95	25.90	5,185	7,860	8,177	12,177
Drilling additions	8.62	15.85	281	2,951	1,718	5,593
Acquisitions	11.74	17.15	4,213	6,217	6,170	9,075
Dispositions	-	-	-	-	-	-
Technical revisions	(1.50)	(6.71)	2,206	926	1,955	(194)
Production	(5.05)	(5.05)	(1,454)	(1,454)	(2,295)	(2,295)
December 31, 2005	31.76	47.14	10,431	16,500	15,725	24,356

* Highpine working interests only – does not include Highpine royalty interests and royalty costs

(000s)	Net Present Values of Future Net Revenue									
	Before Income Taxes Discounted at (%/year)					After Income Taxes Discounted at (%/year)				
Reserves Category	0	5	10	15	20	0	5	10	15	20
Proved										
Developed producing	439,230	382,537	342,028	311,167	286,668	368,429	318,846	284,051	257,883	237,308
Developed non-producing	72,123	63,261	56,901	52,066	48,228	47,255	40,616	36,006	32,593	29,940
Total developed	511,353	445,798	398,929	363,233	334,896	415,684	359,462	320,057	290,476	267,248
Undeveloped	18,126	15,215	13,022	11,319	9,964	11,868	9,821	8,286	7,098	6,157
Total proved	529,479	461,013	411,951	374,552	344,860	427,552	369, 283	328,343	297,574	273,405
Probable	269,397	207,821	169,706	143,569	124,406	181,064	137,237	110,781	92,878	79,854
Total proved plus probable	798,876	668,834	581,657	518,121	469,266	608,616	506,520	439,124	390,452	353,259

PRO FORMA RESERVES*

Although Highpine acquired White Fire on February 21, 2006 and therefore did not beneficially own the oil, NGL and natural gas reserves of White Fire until such time, the reserves information is presented below on a proforma basis as if the acquisition of White Fire had been completed effective December 31, 2005. Information disclosed below under the "Pro Forma Reserves" is shown for convenience of reference, on a pro forma basis effective December 31, 2005, evaluated by Paddock.

	Natural Gas (bcf)	Crude Oil & NGLs (mbbls)	Total (6:1) (mboe)
Proved developed producing	26.72	9,495	13,948
Proved developed non-producing	11.57	1,079	3,007
Proved undeveloped	0.33	546	601
Total proved	38.62	11,120	17,556
Probable additional	19.45	6,455	9,697
Total proved plus probable	58.07	17,575	27,253

(000s)	Net Present Values of Future Net Revenue				
	Before Income Taxes Discounted at (%/year)				
Reserves category	0	5	10	15	20
Proved					
Developed producing	468,563	406,785	363,100	330,009	303,835
Developed non-producing	98,225	85,497	76,892	70,458	65,366
Total developed	566,788	492,282	439,992	400,467	369,201
Undeveloped	18,126	15,215	13,022	11,319	9,964
Total proved	584,914	507,497	453,014	411,786	379,165
Probable	295,557	225,459	182,828	153,832	132,682
Total proved plus probable	880,471	732,956	635,842	565,618	511,847

* Highpine and White Fire working interests only – does not include Highpine and White Fire royalty interests and royalty costs

FINDING, DEVELOPMENT AND ACQUISITION COSTS

For the three year period, the Company's Finding and Development ("F&D") costs for its exploration and development program only, averaged $18.24 per boe for proved plus probable reserves and $25.25 per boe for proved reserves. This includes industry competitive F&D costs of $11.60 and $10.96 per proven plus probable boe for 2003 and 2004 respectively. F&D costs for 2005 of $30.36 per proven plus probable boe are heavily influenced by significant up-front land, seismic and facility expenditures. All told, of the $237 million in exploration and development expenditures invested over the three years, approximately $120 million (51%) relates to the land, seismic and facilities that helped to create our 176 well drilling location inventory, including the facility and infrastructure ownership and control that Highpine enjoys now, and on a go forward basis. The $237 million includes approximately $80 million in the 2005 year alone, a year in which very little high reserve potential Nisku drilling was done.

The acquisition costs were at a reasonable level in 2004, however, the Vaquero merger in 2005 was executed at a high cost of $44.66 per proven plus probable boe. This cost is substantially higher than Company targeted F&D costs, however, the merger was strategic in adding quality production, infrastructure, operating control and consolidation of working interests in many of the Pembina Nisku and West Central Alberta Gas Fairway prospects that form part of our multi-year inventory of drilling opportunities.

On a combined basis, Highpine's three year FD&A cost of $27.86 per proven plus probable boe is higher than our internal targets. However, when considering our inventory of high growth potential opportunities, with the significant up-front costs associated with purchasing land, seismic, production facilities, and acquisition goodwill behind us, the Company is positioned to achieve top quartile full cycle finding, development and acquisition costs over the next several years as our prospect inventory is drilled and reserves are booked. Highpine also expects to continue to receive upward reserve revisions in our Nisku pools, as we have seen in the past few years.

Total Proved Finding, Development and Acquisition Costs

(000s, $/boe)	2005	2004	2003
Excluding effect of acquisition & dispositions			
Total exploration & development capital costs	147,306	66,000	23,279
Net change from previous year's estimated future development costs	3,773	5,589	3,931
Total estimated capital for finding & development costs	151,079	71,589	27,210
Additions to total proved reserves (mboe)	3,673	4,318	1,905
Finding & development costs ($/boe)	41.13	16.58	14.28
Three-year average finding & development cost ($/boe)	25.25	-	-
Including effect of acquisition & dispositions			
Total exploration & development capital costs	552,606	113,747	23,473
Net change from previous year's estimated future development costs	3,773	5,589	3,931
Total estimated capital for finding & development costs	556,379	119,336	27,404
Additions to total proved reserves (mboe)	9,844	6,165	1,770
Finding & development costs ($/boe)	56.52	19.36	15.48
Three-year average finding & development cost ($/boe)	39.55	-	-

Total Proved Plus Probable Finding, Development and Acquisition Costs

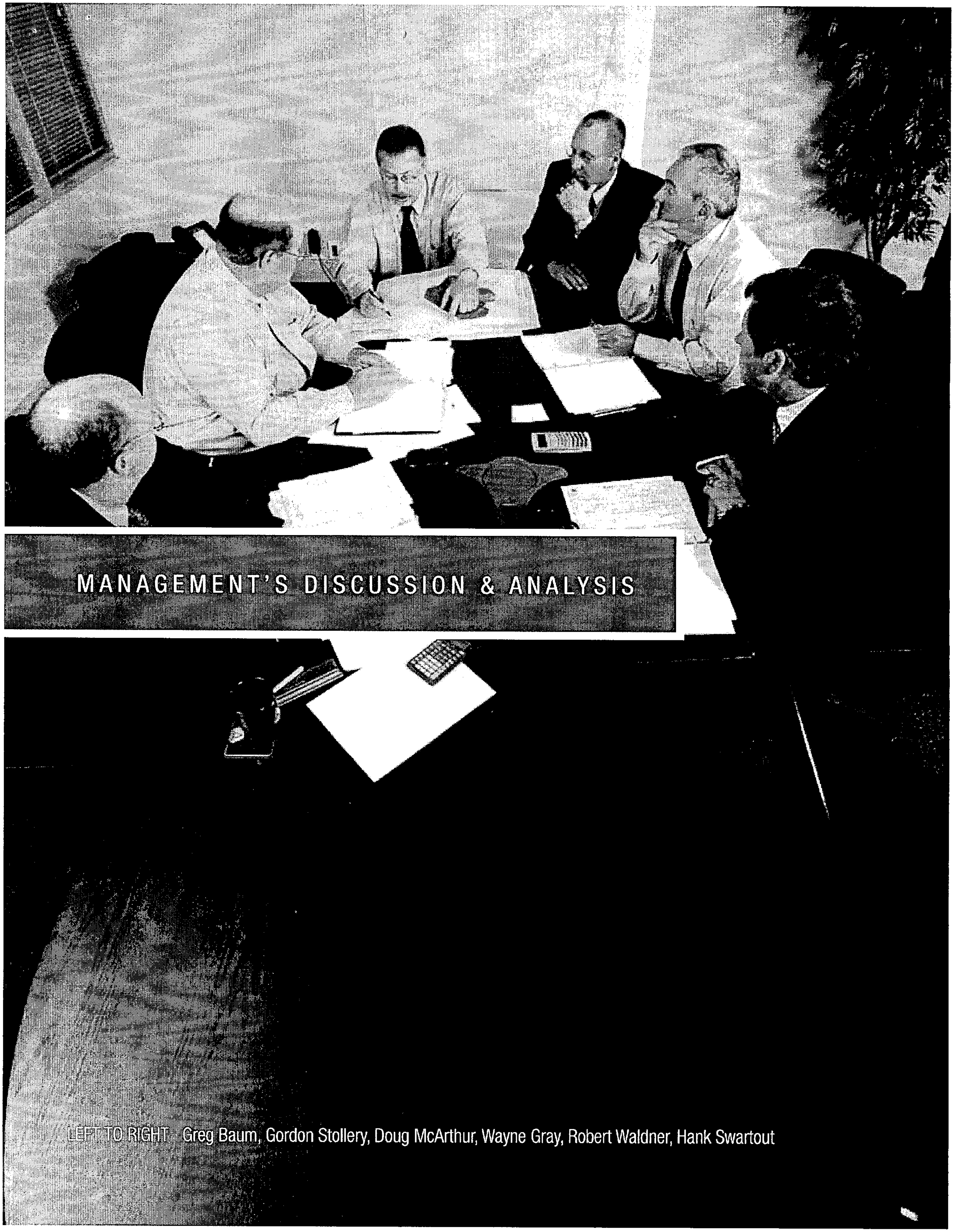
(000s, $/boe)	2005	2004	2003
Excluding effect of acquisition & dispositions			
Total exploration & development capital costs	147,306	66,000	23,279
Net change from previous year's estimated future development costs	16,637	8,542	4,618
Total estimated capital for finding & development costs	163,943	74,542	27,897
Additions to total proved plus probable reserves (mboe)	5,399	6,804	2,404
Finding & development costs ($/boe)	30.36	10.96	11.60
Three-year average finding & development cost ($/boe)	18.24	-	-
Including effect of acquisition & dispositions			
Total estimated exploration & development capital costs	552,606	113,747	23,473
Net change from previous year's estimated future development costs	16,637	8,542	4,618
Total estimated capital for finding & development costs	569,243	122,289	28,091
Additions to total proved plus probable reserves (mboe)	14,474	9,106	2,246
Finding & development costs ($/boe)	39.33	13.43	12.51
Three-year average finding & development cost ($/boe)	27.86	-	-

Note: The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserve additions for that year.

Undeveloped Land Holdings

Area	Gross Acres	Net Acres
Pembina	112,000	87,500
West Central Alberta Gas Fairway	114,000	87,500
Other	80,000	35,000
Total	306,000	210,000

MANAGEMENT'S DISCUSSION & ANALYSIS



LEFT TO RIGHT Greg Baum, Gordon Stollery, Doug McArthur, Wayne Gray, Robert Waldner, Hank Swartout

Overview

This management's discussion and analysis ("MD&A") is dated and based on information at March 7, 2006. This MD&A has been prepared by management and should be read in conjunction with the audited consolidated financial statements for the years ended December 31, 2005 and 2004 for a complete understanding of the financial position and results of operations of Highpine Oil and Gas Limited ("Highpine" or the "Company").

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, especially those in other industries, 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. Highpine also uses operating netbacks as an indicator of operating performance. Operating netback is calculated on a $/boe basis taking the sales price and processing revenues and deducting royalties, operating costs and transportation costs.

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.

Additional information is available on the Company's website at www.highpineog.com. All previous public filings, including the Company's annual information form, are available on SEDAR at www.sedar.com.

Financial Results

ACQUISITION

On May 31, 2005, Highpine acquired Vaquero Energy Ltd. ("Vaquero") for consideration of 19.5 million class A common shares ("Common Shares") of the Company with an ascribed value of $350.9 million (the "Vaquero Acquisition"). Transaction costs of $0.4 million were incurred by Highpine. Vaquero was a public oil and gas exploration and production company active in the Western Canadian sedimentary basin, including the Pembina area of Alberta. The transaction has been accounted for using the purchase method with $257.3 million allocated to property, plant and equipment and $201.7 million allocated to goodwill. The property, plant and equipment allocation includes $78.7 million allocated to unproved lands. A working capital deficiency of $11.1 million and bank debt of $37.0 million were assumed by Highpine. Asset retirement obligations of $1.9 million, a mark-to-market liability on outstanding financial contracts of $0.2 million and future tax liabilities of $57.6 million were also recorded.

OIL AND GAS REVENUES AND PRODUCTION

Daily Production	2005	2004	% Change
Oil and NGLs (bbls/d)	3,984	1,578	152
Natural gas (mcf/d)	13,823	6,423	115
boe/d	6,288	2,648	137
Oil and NGLs	63%	60%	-
Natural gas	37%	40%	-
Total	100%	100%	-

Oil and gas revenues for the year ended December 31, 2005 totalled $147.3 million representing a 237% increase over revenues for the year ended December 31, 2004 of $43.7 million. The increase in revenue is attributable to increased production in the Pembina and Retlaw areas, combined with production from the properties acquired on the Vaquero Acquisition. Production volumes for 2005 averaged 6,288 boe/d compared to an average of 2,648 boe/d in 2004, an increase of 3,640 boe/d or 137%. In addition, higher commodity prices were realized in 2005. Oil and NGL revenue was reduced by a realized hedging expense of $6.1 million (2004 - $2.7 million). Natural gas revenue was reduced by a realized hedging expense of $0.5 million (2004 - nil).

PRICING

Selling Prices before Hedges	2005	2004	% Change
Crude oil and NGLs ($/bbl)	67.16	47.61	41
Natural gas ($/mcf)	9.84	6.91	42
Total combined ($/boe)	64.18	45.13	42

Realized crude oil and NGL prices, prior to hedging expenses, increased 41% in 2005 compared to 2004. Realized natural gas prices increased 42% in 2005 as compared to 2004.

COMMODITY PRICE RISK MANAGEMENT

	2005	2004	% Change
Average volumes hedged (boe/d)	1,086	550	97
% of production hedged	17%	21%	(19)
Realized hedging expense ($000s)	6,613	2,718	143
Realized hedging expense ($/boe)	2.88	2.80	3

The Company had in place a 700 bbl/d crude oil swap agreement at a price of CDN $47.20/bbl for all of 2005. The Company also had in place a 700 bbl/d crude oil collar for the period June 1, 2005 to September 30, 2005 with a price range of US $45.00/bbl to US $54.50/bbl. The crude oil collar was assumed by Highpine on the closing of the Vaquero Acquisition.

The Company had a physical natural gas collar for 3,000 GJ/d with a price range of CDN $5.75/GJ to $7.45/GJ for the period May 31, 2005 to October 31, 2005 that was assumed on the closing of the Vaquero Acquisition.

The Company has entered into the following contracts for 2006:

Term	Contract	Volume	Fixed Price	Unrealized Gains at December 31, 2005 (CDN $000s)
Jan 06 to Dec 06	Oil Collar	2,000 bbls/d	US $60.00 to $69.80	540
Jan 06 to Dec 06	Oil Collar	1,000 bbls/d	US $55.00 to $77.25	135
Jan 06 to Dec 06	Gas Collar	5,000 GJs/d	CDN $9.00 to $14.70	763

ROYALTY EXPENSE

	2005	2004	% Change
Total royalties, net of ARTC ($000s)	38,995	10,140	285
As a % of oil and gas sales (before hedging expense)	26%	23%	13
$/boe	16.99	10.46	62

Royalties as a percentage of oil and gas sales before hedging expense averaged 26% for 2005 compared to 23% for 2004. Royalty rates as a percentage of revenue have been higher in 2005 due to higher royalty rates on wells in the Pembina area, gross overriding royalties payable on certain wells in the West Central Gas Fairway and royalty holidays expiring on certain wells.

OPERATING COSTS, TRANSPORTATION COSTS AND PROCESSING REVENUES

	2005	2004	% Change
Operating costs ($000s)	16,210	6,363	155
$/boe	7.06	6.56	8
Processing revenues ($000s)	(2,010)	(1,026)	96
$/boe	(0.88)	(1.06)	(17)
Operating costs (net of processing) $/boe	6.18	5.50	12
Transportation costs ($000s)	2,814	598	371
$/boe	1.23	0.62	98
Combined $/boe	7.41	6.12	21

On a combined basis, operating costs and transportation costs net of processing revenues increased 21% from $6.12/boe to $7.41/boe.

Operating costs were $16.2 million for 2005 compared to $6.4 million for 2004. Operating costs increased 8% to $7.06/boe for 2005 from $6.56/boe for 2004. These increases are a result of higher industry related costs, as well as higher operating costs in the Pembina area.

Transportation costs for 2005 were 371% higher than for 2004 primarily due to higher production volumes in 2005. In addition, Highpine incurred $0.9 million of sulphur trucking costs for wells in the Pembina area, including a one-time charge of $0.4 million relating to the prior year. On a per unit basis, gas pipeline fees and transportation totalled $0.22/mcf (2004 - $0.16/mcf) and oil trucking was $0.31/bbl (2004 - $0.37/bbl).

In 2005, the Company earned $2.0 million of processing revenues up from $1.0 million in 2004. The increase in processing revenues is primarily attributable to the Joffre gas plant which commenced operations in January of 2005 as well as from facilities in the Pembina area.

OPERATING NETBACKS

($/boe)	2005	2004	% Change
Sales price before hedging	64.18	45.13	42
Processing revenues	0.88	1.06	(17)
Royalties	(16.99)	(10.46)	62
Operating costs	(7.06)	(6.56)	8
Transportation costs	(1.23)	(0.62)	98
Netback before hedges	39.78	28.55	39
Realized hedging expense	(2.88)	(2.80)	3
Operating netbacks	36.90	25.75	43

Operating netbacks before hedging expense increased 39% from $28.55/boe in 2004 to $39.78/boe for 2005 as a result of higher commodity prices in 2005 partially offset by higher royalties, operating costs and transportation costs.

GENERAL AND ADMINISTRATIVE EXPENSES

	2005	2004	% Change
Gross expenses ($000s)	7,154	3,110	130
Capitalized ($000s)	(1,377)	(295)	367
Net expenses ($000s)	5,777	2,815	105
$/boe	2.52	2.90	(13)
% capitalized	19	9	111

General and administrative expenses decreased 13% on a $/boe basis from $2.90/boe in 2004 to $2.52/boe in 2005 as a result of increased production volumes in the year.

STOCK BASED COMPENSATION

Stock based compensation expense of $3.2 million was recorded in 2005 compared to $0.4 million in 2004. The increase was primarily the result of stock options granted to former Vaquero employees that have remained with Highpine and to new employees hired in the year.

INTEREST AND FINANCE COSTS

Interest and finance costs for 2005 were $3.6 million, an increase of 58% from $2.3 million 2004. Interest and finance costs were higher in 2005 due to higher average debt levels as a result of capital expenditures incurred.

DEPLETION, DEPRECIATION AND ACCRETION

	2005	2004	% Change
Depletion, depreciation and accretion ($000s)	53,893	14,887	262
$/boe	23.48	15.36	53

Depletion, depreciation and accretion ("DD&A") amounted to $53.9 million or $23.48/boe for 2005, compared with $14.9 million or $15.36/boe in 2004, a 53% increase on a $/boe basis. The increase is attributable to significant capital expenditures incurred in 2005 combined with the costs of the Vaquero Acquisition.

INCOME TAXES

Cash taxes of $0.7 million for 2005 (2004 - $0.2 million) relate to the Federal Large Corporation Tax. Large Corporation Tax was higher in 2005 as a result of a higher capital tax base resulting from the completion of the Vaquero Acquisition on May 31, 2005. 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 in 2006.

CASH FLOW AND NET EARNINGS

	2005	2004	% Change
Funds from operations ($000s)	74,550	19,773	277
Per diluted share	2.09	1.16	80
Net earnings ($000s)	12,274	3,177	286
Per diluted share	0.34	0.19	79

Funds from operations increased 277% to $74.6 million in 2005 compared to $19.8 million in 2004 with funds from operations per diluted share increasing 80% for the year. The increase of funds from operations as well as per diluted share in 2005 is attributable to higher commodity prices and significantly higher production volumes realized in 2005. Net income increased 286% to $12.3 million in 2005 from $3.2 million in 2004.

LIQUIDITY AND CAPITAL RESOURCES

($000s)	2005	2004
Bank debt	104,707	34,822
Working capital deficiency	4,892	14,815
Net debt	109,599	49,637

At December 31, 2005, the Company had a revolving term credit facility of $105 million and a demand operating credit facility of $20 million. At December 31, 2005, Highpine had a working capital deficiency of $4.9 million and net debt of $109.6 million. The bank debt was $104.7 million or 84%, providing excess credit capacity of $20.3 million. On February 21, 2006, the amount available under the Company's credit facilities was increased from $125 million to $150 million.

Highpine's 2006 capital budget of approximately $160 million will be funded from available bank debt, cash flow from operations and the proceeds of a bought deal equity financing which closed on February 23, 2006. The bought deal equity financing resulted in Highpine issuing 4.3 million common shares at $23.40 per share for net cash proceeds of $96.6 million.

At March 7, 2006, Highpine's bank debt was approximately $26.0 million which includes the assumption of $3.7 million of White Fire's bank debt.

CAPITAL EXPENDITURES

($ millions)	2005	2004	% Change
Land	42.3	12.4	241
Seismic	14.4	4.8	200
Drilling and completions	54.2	27.2	99
Facilities and equipment	36.4	21.6	69
Property acquisitions and disposition (net)	3.8	(5.0)	-
Office and other	2.5	0.1	2,400
Total	153.6	61.1	151

Capital expenditures, excluding corporate acquisitions and net of property dispositions, were $153.6 million for the year ended December 31, 2005 compared to $61.1 million for 2004. Highpine incurred significant expenditures at Crown land sales acquiring parcels in Pembina and the Company's West Central Gas Fairway. Drilling and completion expenditures were focused in Pembina and the Company's West Central Gas Fairway. Facility expenditures were primarily attributable to Highpine's Violet Grove oil processing facilities. Other expenditures are comprised of office related expenditures including the acquisition of a field office building in Drayton Valley.

CONTRACTUAL OBLIGATIONS

The Company was committed to make future payments pursuant to contractual obligations at December 31, 2005 as follows:

($000s)	Total	2006	2007/2008	2009/2010	After 2010
Operating leases [1]	8,355	1,261	2,354	2,420	2,320

Notes: [1] Operating leases include leases for office space and field equipment.

SHAREHOLDERS' EQUITY

During 2005, 47,500 Common Shares were issued on the exercise of stock options for proceeds of $0.2 million.

The Company issued 4.0 million Common Shares at a price of $18.00 per share for gross proceeds totalling $72.0 million pursuant to its initial public offering. Costs associated with the issuance of the Common Shares were $4.8 million including the underwriters' fee of $3.7 million. On April 5, 2005, the issued and outstanding Common Shares were listed and posted for trading on the Toronto Stock Exchange under the symbol "HPX".

The Company also issued 19.5 million Common Shares to acquire all the outstanding shares of Vaquero Energy Ltd. on May 31, 2005.

OUTSTANDING COMMON SHARES

As at March 7, 2006, the Company had 52.8 million Common Shares outstanding and had granted options to employees, directors and officers to acquire a further 4.5 million Common Shares.

FOURTH QUARTER REVIEW

The following are the highlights of the fourth quarter of 2005:

- Highpine's funds from operations increased by 347% from $6.3 million in the fourth quarter of 2004 to $28.0 million in the fourth quarter of 2005. Funds from operations per diluted share increased by 100% as a result of cash flow generated from properties relating to the Vaquero Acquisition, increased production from Highpine's drilling program and higher commodity prices. Highpine's production increased from 3,027 boe/d in the fourth quarter of 2004 to 8,549 boe/d in the fourth quarter of 2005.
- Highpine acquired a 15% interest in the Dominion Violet Grove oil battery and also increased its interest in the Keyera Easyford facility.

PROPOSED TRANSACTION

On December 12, 2005, Highpine announced that it had entered into an agreement with White Fire Energy Ltd. ("White Fire") whereby Highpine would acquire all the issued and outstanding shares of White Fire pursuant to a plan of arrangement. On February 21, 2006, upon closing the plan of arrangement, shareholders of White Fire received 0.132 Common Shares of the Company for each common share of White Fire held resulting in the Company issuing approximately 4.1 million Common Shares to the former White Fire shareholders. On February 21, 2006, Highpine assumed $3.7 million outstanding on White Fire's credit facility which was repaid using Highpine's credit facilities.

The acquisition of White Fire will increase the Company's production of crude oil, natural gas and natural gas liquids which is expected to result in increased earnings and increased cash flows.

TRANSACTION WITH RELATED PARTY

As at December 31, 2005, $122,000 was due from an officer of the Company. The loan was repaid in February 2006.

RESOLUTION OF CONTINGENCY

On December 14, 2004, the Company was granted a license from the Alberta Energy and Utilities Board (the "EUB") relating to the expansion of an existing facility. On December 15, 2004, a notice of objection was filed with the EUB by a corporation which is a joint lease owner where the facility was being constructed. In the fourth quarter of 2005, the corporation rescinded the objection.

CHANGES IN ACCOUNTING POLICIES IN THE CURRENT PERIOD

Variable Interest Entities

Effective January 1, 2005, the Company adopted the new CICA accounting guideline 15 ("AcG-15"), "Consolidation of Variable Interest Entities". This standard requires that certain entities be consolidated by the primary beneficiary. There is no impact on the Company's financial statements as a result of adopting this guideline.

FUTURE ACCOUNTING CHANGE

Financial Instruments

The CICA has issued a new accounting standard, CICA Accounting Standard Handbook section 3855, "Financial Instruments Recognition and Measurement." This standard prescribes how and at what amount financial assets, financial liabilities and non-financial derivatives are to be recognized on the balance sheet. The standard prescribes fair value in some cases while cost-based measures are prescribed in other cases. It also specifies how financial instrument gains and losses are to be presented. The new standard is effective for fiscal years beginning on or after October 1, 2006. The Company has not assessed the impact of this standard on its financial statements.

CRITICAL ACCOUNTING ESTIMATES

The preparation of the Company's financial statements requires management to adopt accounting policies that involve the use of significant estimates and assumptions. These estimates and assumptions are developed based on the best available information and are believed by management to be reasonable under the existing circumstances. New events or additional information may result in the revision of these estimates over time. A summary of the significant accounting policies used by Highpine can be found in Note 2 to the December 31, 2005 consolidated financial statements. The following discussion outlines what management believes to be the most critical accounting policies involving the use of estimates or assumptions.

Depletion, Depreciation and Accretion

Highpine follows CICA accounting guideline AcG-16 on full cost accounting in the oil and gas industry to account for oil and gas properties. Under this method, all costs associated with the acquisition of, exploration for, and the development of crude oil and natural gas reserves are capitalized and costs associated with production are expensed. The capitalized costs are depleted using the unit-of-production method based on estimated proved reserves using management's best estimate of future prices. Reserves estimates can have a significant impact on earnings, as they are a key component in the calculation of depletion.

Asset Impairment

Producing properties and unproved properties are assessed annually, or as economic events dictate, for impairment. The cash flows used in the impairment assessment require management to make estimates and assumptions as to recoverable reserves, future commodity prices and operating costs. Changes in any of the estimates or assumptions could result in an impairment of the carrying value of producing properties and unproved properties.

Asset Retirement Obligations

Asset retirement obligations require that management make estimates and assumptions regarding future liabilities and cash flows involving environmental reclamation and remediation. Estimates of future liabilities and cash flows are subject to uncertainty associated with the method of reclamation and remediation, environmental legislation, the timing of reclamation and remediation activities and the cost of reclamation and remediation activities.

Purchase Price Allocation

Business acquisitions are accounted for by the purchase method of accounting. Under this method, the purchase price is allocated to the assets acquired and the liabilities assumed based on the fair value at the time of acquisition. The excess purchase price over the fair value of identifiable assets and liabilities acquired is goodwill. The determination of fair value often requires management to make assumptions and estimates about future events. The assumptions and estimates with respect to determining the fair value of property, plant and equipment acquired generally require the most judgment and include estimates of reserves acquired, future commodity prices and discount rates. Future net earnings can be affected as a result of changes in future depletion and depreciation, asset impairment or goodwill impairment.

Goodwill Impairment

Goodwill is subject to impairment tests annually, or as economic events dictate, by comparing the fair value of the reporting entity to its carrying value, including goodwill. If the fair value of the reporting entity is less than its carrying value, a goodwill impairment loss is recognized as the excess of the carrying value of the goodwill over the implied value of the goodwill. The determination of fair value requires management to make assumptions and estimates about recoverable reserves, future commodity prices, operating costs, production profiles and discount rates. Changes in any of these assumptions, such as a downward revision in reserves, a decrease in future commodity prices, an increase in operating costs or an increase in discount rates could result in an impairment of all or a portion of the goodwill carrying values in future periods.

Accounting for Stock Options

The Company recognizes compensation expense on options granted to employees. Compensation expense is based on the theoretical fair value of each option at its grant date, the estimation of which requires management to make assumptions about the future volatility of the Company's stock price, future interest rates and the timing of employee's decisions to exercise the options. The effects of a change in one or more of these variables could result in a materially different fair value.

DISCLOSURE CONTROLS

Highpine's Chief Executive Officer and Chief Financial Officer have evaluated the Company's disclosure controls and procedures as at December 31, 2005. Based on that evaluation, these officers have concluded that the Company's disclosure controls and procedures are effective in ensuring that material information required to be in this annual report is made known to them on a timely basis.

BUSINESS RISKS AND UNCERTAINTIES

Highpine is exposed to numerous risks and uncertainties associated with the exploration for and development, production and acquisition of crude oil, natural gas and NGLs. Primary risks include:

- Uncertainty associated with obtaining drilling licenses;
- Finding and producing reserves economically;
- Marketing reserves at acceptable prices; and
- Operating with minimal environmental impact.

Highpine strives to minimize and manage these risks in a number of ways, including:

- Employing qualified professional and technical staff;
- Communicating openly with members of the public regarding our activities;
- Concentrating in a limited number of areas;
- Utilizing the latest technology for finding and developing reserves;
- Constructing quality, environmentally sensitive, safe production facilities;
- Maximizing operational control of drilling and producing operations; and
- Minimizing commodity price risk through strategic hedging.

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. These risks should not be construed as exhaustive.

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 its 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.

SELECTED ANNUAL INFORMATION

($000s except per share data)	2005	2004	2003	2002	2001
FINANCIAL					
Total revenues[1]	143,644	42,051	17,459	6,647	3,005
Net earnings	12,274	3,177	19,108	1,017	29
Per share – basic	0.35	0.19	1.26	0.08	0.00
Per share – diluted	0.34	0.19	1.25	0.08	0.00
Funds from operations	74,550	19,773	11,616	3,130	889
Per share - basic	2.13	1.18	0.77	0.24	0.08
Per share – diluted	2.09	1.16	0.76	0.24	0.08
Corporate acquisitions	257,314	51,151	-	-	-
Capital expenditures[2]	153,606	61,133	24,651	11,268	2,638
Total assets	753,690	163,388	34,386	23,594	12,611
OPERATING					
Average daily production:					
Oil and NGLs (bbls/d)	3,984	1,578	443	301	237
Gas (mcf/d)	13,823	6,423	4,281	1,809	545
Total (boe/d)	6,288	2,648	1,157	603	328

Notes: (1) Total revenues are after realized and unrealized hedging expense and include processing revenues.
(2) Capital expenditures are net of property dispositions.

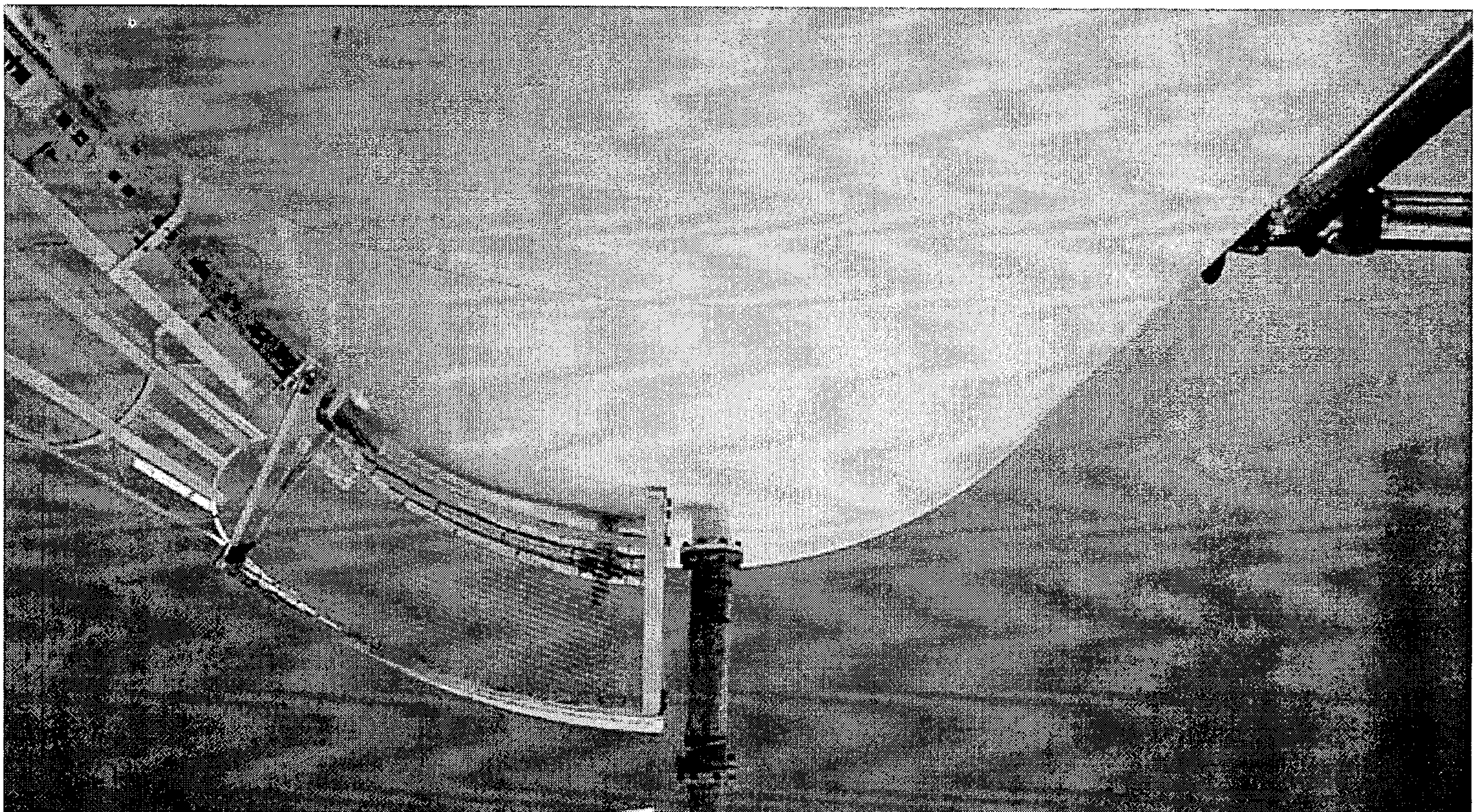
Highpine's net earnings for the year ended December 31, 2003 were positively impacted by the sale of the Company's investment in Monolith Oil Corp. which resulted in a one-time gain of $17.4 million.

SUMMARY OF QUARTERLY RESULTS

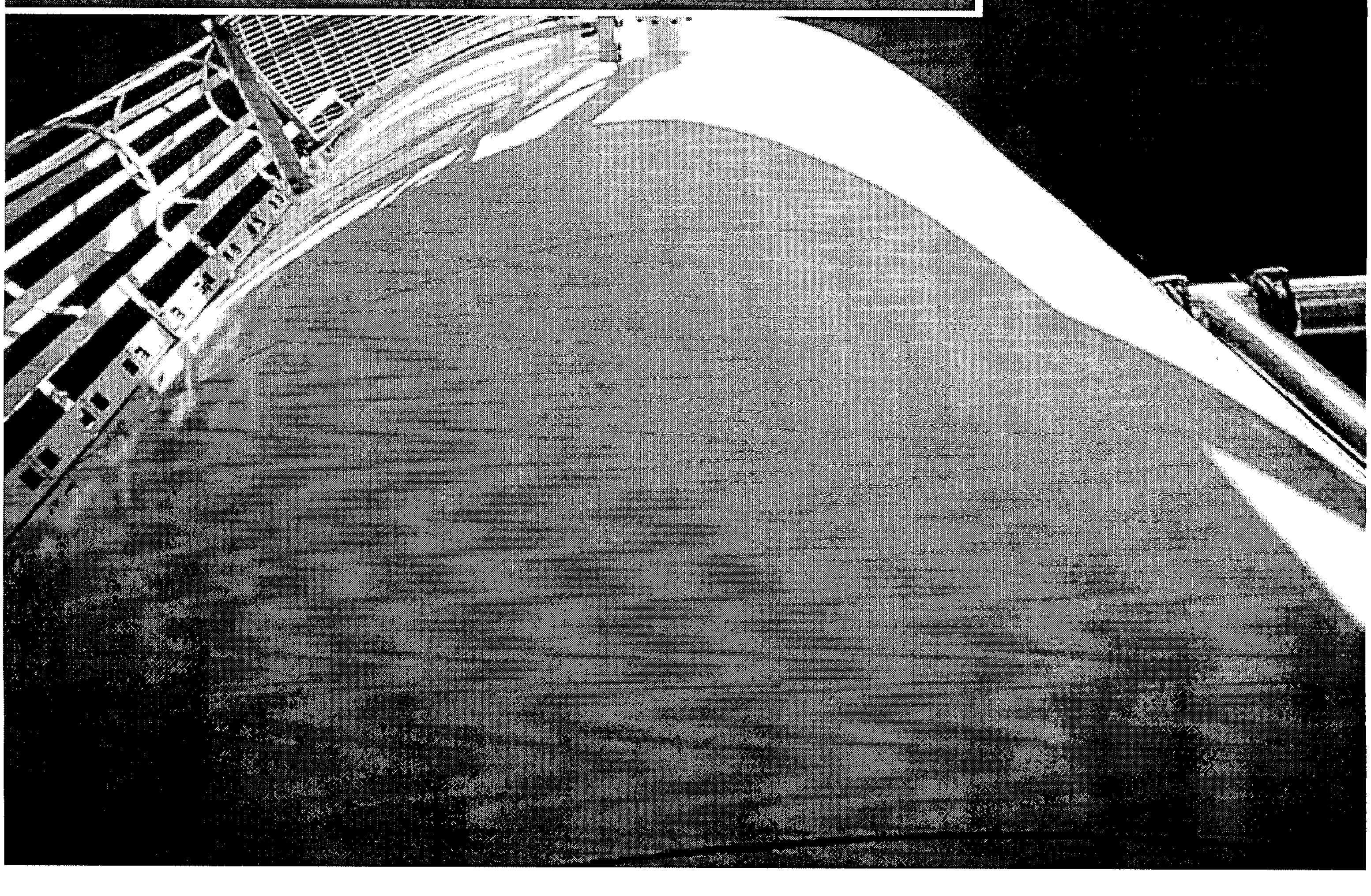
	2005				2004			
($000s except per share data)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
FINANCIAL								
Total revenues[1]	54,614	52,075	22,320	14,635	12,585	11,787	11,359	6,320
Net earnings (loss)	4,855	6,683	(32)	768	1,046	507	1,371	252
Per share – basic	0.11	0.15	(0.00)	0.04	0.05	0.03	0.09	0.02
Per share – diluted	0.11	0.15	(0.00)	0.04	0.05	0.03	0.09	0.02
Funds from operations	27,957	29,796	9,856	6,941	6,254	5,229	5,493	2,797
Per share - basic	0.63	0.67	0.31	0.32	0.31	0.31	0.36	0.18
Per share – diluted	0.62	0.65	0.31	0.32	0.31	0.31	0.36	0.18
Corporate acquisitions	-	-	257,314	-	-	-	-	51,151
Capital expenditures[2]	50,861	48,149	19,839	34,757	23,619	12,305	16,711	8,498
Total assets	753,690	715,360	677,834	198,599	163,388	138,941	129,187	117,641
OPERATING								
Average daily production								
Oil and NGLs (bbls/d)	5,881	5,562	2,617	1,816	1,897	1,812	1,628	969
Gas (mcf/d)	16,006	18,277	11,593	9,293	6,784	7,091	6,759	5,046
Total (boe/d)	8,549	8,608	4,549	3,365	3,027	2,994	2,754	1,810

Notes: (1) Total revenues are after realized and unrealized hedging expense and include processing revenues.
(2) Capital expenditures are net of property dispositions.

Highpine's revenue has increased through the previous eight quarters as a result of production from the properties acquired on the acquisitions of Vaquero in May 2005 and Rubicon Energy Corporation in March 2004 and the Company's drilling programs.



CONSOLIDATED FINANCIAL STATEMENTS



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 auditor, 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.

A. Gordon Stollery President and Chief Executive Officer	Harry D. Cupric Vice President, Finance and Chief Financial Officer

Calgary, Canada
February 24, 2006

Auditors' Report To The Shareholders

We have audited the consolidated balance sheets of Highpine Oil & Gas Limited as at December 31, 2005 and 2004 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, 2005 and 2004 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants
Calgary, Canada
February 24, 2006

Consolidated Balance Sheets

As at December 31 (Thousands)

	2005	2004
Assets		
Current assets:		
Accounts receivable (note 4)	$ 40,716	$ 13,366
Prepaid expenses and deposits	1,795	659
Financial instruments (note 13)	763	-
	43,274	14,025
Property, plant and equipment (note 5)	493,330	134,282
Long-term investment, at cost (note 6)	1,000	1,000
Deferred charges (note 7)	251	-
Goodwill (note 3)	215,835	14,081
	$ 753,690	$ 163,388
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$ 47,403	$ 28,840
Bank indebtedness (note 8)	104,707	34,822
	152,110	63,662
Future income taxes (note 10)	84,167	20,419
Asset retirement obligations (note 9)	5,898	1,974
Deferred lease inducements	492	-
Shareholders' equity:		
Share capital (note 11)	479,496	52,830
Contributed surplus (note 11)	3,627	511
Retained earnings	27,900	23,992
	511,023	77,333
Commitments (note 12)		
Subsequent events (notes 4, 8 and 14)		
	$ 753,690	$ 163,388

See accompanying notes to consolidated financial statements.

On behalf of the Board:

Andrew Krusen
Director

Richard Carl
Director

Consolidated Statements of Earnings and Retained Earnings

For the years ended December 31 (Thousands, except per share amounts)

	2005	2004
Revenues:		
Oil and gas revenues	$ 147,303	$ 43,743
Royalties, net of Alberta Royalty Tax Credits	(38,995)	(10,140)
Financial instruments:		
Realized (losses)	(6,613)	(2,718)
Unrealized gains	944	-
	102,639	30,885
Processing revenues	2,010	1,026
Interest and other income	7	406
	104,656	32,317
Expenses:		
Operating costs	16,210	6,363
Transportation costs	2,814	598
General and administrative	5,777	2,815
Depletion, depreciation and accretion	53,893	14,887
Interest and finance costs	3,631	2,296
Stock based compensation (note 11)	3,151	396
	85,476	27,355
Earnings before taxes	19,180	4,962
Taxes (note 10):		
Current	723	185
Future	6,183	1,600
	6,906	1,785
Net earnings	12,274	3,177
Retained earnings, beginning of year	23,992	20,815
Stock dividend and adjustment (note 11)	(8,366)	-
Retained earnings, end of year	$ 27,900	$ 23,992
Net earnings per share (note 11)		
Basic	$ 0.35	$ 0.19
Diluted	$ 0.34	$ 0.19

See accompanying notes to consolidated financial statements.

Consolidated Statements of Cash Flows

For the years ended December 31 (Thousands)

		2005		2004
Cash provided by (used in):				
Operations:				
Net earnings	$	12,274	$	3,177
Items not involving cash:				
Depletion, depreciation and accretion		53,893		14,887
Gain on sale of investment		-		(350)
Future income taxes		6,183		1,600
Shares issued for services performed		-		63
Stock based compensation		3,151		396
Unrealized gains on financial instruments		(944)		-
Amortization of deferred lease inducements		(7)		-
Funds from operations		74,550		19,773
Change in non-cash operating working capital		(18,017)		(2,940)
		56,533		16,833
Financing:				
Common shares issued for cash, net of share issue costs		67,189		10,692
Special warrants issued for cash, net of issue costs		-		27,981
Proceeds on exercise of stock options		176		-
Increase in bank indebtedness		32,857		31,428
		100,222		70,101
Investments:				
Property, plant and equipment additions		(154,015)		(66,106)
Debenture receivable repayment		-		3,737
Proceeds on sale of investment		-		350
Long-term investment, at cost		-		(760)
Proceeds on the disposition of property, plant and equipment		409		4,973
Net cash paid on business combination (note 3)		(429)		(42,089)
Deferred lease inducements		581		-
Deferred charges (note 7)		(251)		-
Change in non-cash investing working capital		(3,050)		12,424
		(156,755)		(87,471)
Decrease in cash and cash equivalents		-		(537)
Cash and cash equivalents, beginning of year		-		537
Cash and cash equivalents, end of year	$	-	$	-
Supplemental disclosure of cash flow information				
Cash taxes paid	$	494	$	60
Cash interest paid		3,070		1,651

See accompanying notes to consolidated financial statements.

Notes to Consolidated Financial Statements

For the years ended December 31, 2005 and 2004 (Tabular amounts in thousands except per share amounts)

1 DESCRIPTION OF BUSINESS:

Highpine Oil & Gas Limited (the "Company") was incorporated under the laws of the Province of Alberta on April 2, 1998. The Company is engaged in the exploration for, and the development and production of crude oil, natural gas and natural gas liquids in Western Canada.

2 SIGNIFICANT ACCOUNTING POLICIES:

a) Principles of consolidation:

These consolidated financial statements include the accounts of the Company and its subsidiaries.

b) Property, plant and equipment:

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 and accumulated in one cost centre. These costs include lease acquisition costs, geological and geophysical expenses, carrying charges of unproved 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.

Depletion, depreciation and amortization

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 costs of acquiring and evaluating unproved 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.

Office equipment and computers are depreciated on a declining balance basis at 20% per year. Leasehold improvements are amortized on a straight line basis over the lease term. Buildings are amortized on a straight line basis over 20 years. Land is not depreciated.

Ceiling test

The Company 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 ceiling test is an impairment test whereby the carrying amount of property, plant and equipment is compared to the sum of the undiscounted cash flows expected from the production of proved reserves and the lower of cost and market of unproved properties. If the carrying amount exceeds the undiscounted cash flows, an impairment loss would be determined by comparing the carrying amount to the sum of the net present value of future pre-tax cash flows from proved plus probable reserves and the lower of cost or market value of the Company's unproved properties. The impairment loss would be recorded in income.

c) Asset retirement obligations:

The Company recognizes the fair value of an Asset Retirement Obligation ("ARO") in the period in which it is incurred. The fair value of the estimated ARO is recorded as a liability on a discounted basis, 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.

d) **Goodwill:**

The Company records goodwill 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 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.

e) **Revenue recognition:**

Revenues from the sale of crude oil, natural gas and natural gas liquids are recorded when title passes to the customer.

f) **Long-term investment:**

The Company's long-term investment is accounted for by the cost method (see note 6). 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) **Financial instruments:**

The Company may enter into derivative instrument contracts to manage its commodity price exposure. The Company does not enter into derivative instrument contracts for trading or speculative purposes. When the Company enters into a hedge it formally assesses both at the hedge's inception and on an ongoing basis whether the hedge is highly effective in offsetting changes in cash flows of the hedged item. These derivative contracts, accounted for as hedges, are not recognized on the balance sheet. Realized gains and losses on these contracts are recognized in revenues in the same period in which the revenues associated with the hedged transactions are recognized. Financial instruments that do not qualify as effective hedges for accounting purposes are recorded on a mark-to-market basis with the resulting gains or losses taken into income.

h) **Future income taxes:**

The Company follows 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 a change in rates on future income tax liabilities and assets is recognized in the period in which the change occurs.

i) **Stock-based compensation:**

The Company records compensation expense using the fair value method. Under the fair value method, a compensation cost is measured at fair value 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 received together with the amount previously recorded in contributed surplus is recorded as an increase to share capital.

j) **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. A future tax liability is recognized upon the renunciation of tax pools and share capital is reduced by a corresponding amount.

k) 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.

l) Earnings per share:

Basic earnings per common share are computed by dividing earnings 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. The treasury stock method assumes that proceeds received from the exercise of in-the-money stock options are used to repurchase common shares at the average market price for the reporting period.

m) Joint ventures:

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.

n) Measurement uncertainty:

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 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.

o) Deferred lease inducements:

Deferred lease inducements are accounted for as a reduction of rent expense over the term of the lease.

3 ACQUISITIONS:

Vaquero Energy Ltd:

On May 31, 2005, the Company acquired Vaquero Energy Ltd. ("Vaquero") for consideration of 19.5 million class A common shares with an ascribed value of $350.9 million. Vaquero was a public oil and gas exploration and production company active in the Western Canadian sedimentary basin. The transaction has been accounted for using the purchase method with the allocation of the purchase price as follows:

Net assets acquired and liabilities assumed		
Property, plant and equipment (including unproved properties totalling $78,657)	$	257,314
Goodwill		201,754
Working capital deficiency		(11,062)
Bank debt		(37,028)
Asset retirement obligations		(1,903)
Financial instruments		(181)
Future income taxes		(57,569)
	$	351,325
Consideration		
Acquisition costs	$	429
Class A common shares issued		350,896
	$	351,325

Rubicon Energy Corporation:

In March 2004, the Company acquired 50% of the issued and outstanding shares of Rubicon Energy Corporation ("Rubicon"). Rubicon was a private oil and gas exploration and production company active in the Western Canadian sedimentary basin. The transaction has been accounted for using the purchase method with the allocation of the purchase price as follows:

Net assets acquired and liabilities assumed	
Property, plant and equipment	$ 51,151
Goodwill	14,081
Working capital deficiency	(6,314)
Bank debt	(3,394)
Asset retirement obligations	(950)
Future income taxes	(12,485)
	$ 42,089
Consideration	
Acquisition costs	$ 279
Cash paid	41,810
	$ 42,089

4 ACCOUNTS RECEIVABLE:

As at December 31, 2005, accounts receivable included a loan due from an officer of the Company totalling $122,000 including accrued interest (December 31, 2004 - $117,000). The loan bears interest at 4.75% compounded annually, is due on demand and is secured by the pledge of 57,143 class A common shares of the Company. Subsequent to December 31, 2005, the loan was repaid in its entirety.

5 PROPERTY, PLANT AND EQUIPMENT:

2005	Cost	Accumulated depletion and depreciation	Net book value
Petroleum and natural gas properties	$ 566,538	$ 75,869	$ 490,669
Land, buildings and leaseholds	2,358	41	2,317
Office equipment and computers	594	250	344
	$ 569,490	$ 76,160	$ 493,330
2004			
Petroleum and natural gas properties	$ 156,534	$ 22,439	$ 134,095
Land, buildings and leaseholds	11	2	9
Office equipment and computers	342	164	178
	$ 156,887	$ 22,605	$ 134,282

At December 31, 2005, $112.4 million (2004 - $13.0 million) of unproved properties were excluded from the depletion calculation and future development costs of $13.3 million (2004 - $9.5 million) were included in the depletion calculation.

During the year ended December 31, 2005, the Company capitalized $1.4 million (2004 - $0.3 million) of general and administrative expenses.

The Company performed a ceiling test at December 31, 2005 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, 2005.

	Oil/bbl	Gas/mcf	Condensate/bbl	NGLs/bbl
2006	$ 65.83	$ 11.35	$ 68.62	$ 55.36
2007	63.21	10.20	65.88	52.75
2008	60.51	8.85	62.65	50.58
2009	57.51	8.15	59.47	48.43
2010	54.45	7.45	56.39	46.20
2011 and thereafter	54.31	8.34	57.57	48.30

Prices after 2010 escalate at approximately 1% to 2% per annum.

6 LONG-TERM INVESTMENT:

At December 31, 2005, the Company's long-term investment of $1.0 million was comprised of 960,000 common shares of In Depth Resources Ltd., a private oil and gas company in which the Chairman of the Company is a director. The Company has a right of first refusal to participate in certain prospects generated by In Depth Resources Ltd.

7 DEFERRED CHARGES:

In December 2005, the Company incurred various costs in connection with the acquisition of White Fire Energy Ltd. (note 14). Deferred charges represent part of the overall consideration paid and will be allocated to the net assets acquired on the acquisition of White Fire Energy Ltd.

8 BANK INDEBTEDNESS:

At December 31, 2005, the Company had available a $105 million revolving term credit facility and a $20 million demand operating credit facility with Canadian financial institutions. The revolving term credit facility bears interest within a range of the lenders' prime rate to prime plus 0.25% depending on the Company's ratio of consolidated debt to net income before interest, taxes, depletion, depreciation, accretion and compensation expense. The demand operating credit facility bears interest at the lenders' prime rate. The facilities are reviewed and renewed semi-annually on April 30 and October 31. The facilities are secured by a general security agreement and a first floating charge over all of the Company's assets.

On February 21, 2006, the amount available under the Company's credit facilities was increased from $125 million to $150 million.

9 ASSET RETIREMENT OBLIGATIONS:

At December 31, 2005, the estimated total undiscounted amount required to settle asset retirement obligations was $10.0 million which will be incurred between 2006 and 2026. This amount has been discounted using a credit adjusted risk-free interest rate of 8.0 % per annum and inflated using an inflation rate of 2.0 % per annum.

Changes to asset retirement obligations were as follows:

	2005	2004
Asset retirement obligations, beginning of year	$ 1,974	$ 378
Liabilities acquired	1,903	950
Liabilities incurred	1,694	1,144
Liabilities disposed of	-	(600)
Accretion	327	102
Asset retirement obligations, end of year	$ 5,898	$ 1,974

10 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 37.62% (2004 – 38.62%) to earnings before taxes. The difference results from the following:

	2005	2004
Effective tax rate	37.62%	38.62%
Computed expected income taxes	$ 7,216	$ 1,915
Add (deduct):		
Non-deductible crown payments, net of Alberta Royalty Tax Credits	5,326	2,494
Resource allowance	(4,466)	(2,146)
Large corporation tax	723	185
Non-taxable portion of capital gains	-	(70)
Stock based compensation	1,185	153
Effect of change in tax rate and other	(3,078)	(746)
	$ 6,906	$ 1,785

The components of the future income tax liability at December 31, 2005 and 2004 are as follows:

	2005	2004
Property, plant and equipment net book value in excess of tax value	$ 68,203	$ 11,472
Partnership deferral	28,182	11,656
Asset retirement obligations	(1,983)	(622)
Attributed royalty income deductible for provincial taxes	(2,074)	(234)
Share issue costs	(2,758)	(648)
Loss carryforward	(5,700)	(1,251)
Financial instruments	257	-
Long-term investment	40	46
Future income tax liability	$ 84,167	$ 20,419

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.

11 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.

(b) Shares issued:

	2005		2004	
	Number	Amount	Number	Amount
Class A common shares:				
Balance, beginning of year	15,208	$ 24,247	13,195	$ 13,455
Issued for cash	4,000	72,000	1,200	6,000
Issued to acquire Vaquero	19,494	350,896	-	-
Shares issued for services performed	-	-	13	63
Conversion of class B shares	1,271	1	-	-
Special warrants exercised	3,300	28,582	-	-
Stock dividend and adjustment	930	8,366	-	-
Stock option exercises	47	176	-	-
Contributed surplus transferred on exercise of options	-	35	-	-
Flow-through shares issued	-	-	800	4,800
Flow-through shares renounced	-	(1,613)	-	-
Share issue costs less tax effect of (2005 - $1,617; 2004 - $38)	-	(3,194)	-	(71)
Balance, end of year	44,250	479,496	15,208	24,247
Class B common shares:				
Balance, beginning of year	1,271	1	1,271	1
Conversion of class B shares	(1,271)	(1)	-	-
Balance, end of year	-	-	1,271	1
Special warrants:				
Balance, beginning of year	3,300	28,582	-	-
Issued for cash	-	-	3,300	29,700
Exercised	(3,300)	(28,582)	-	-
Share issue costs less tax effect of (2004 - $602)	-	-	-	(1,118)
Balance, end of year	-	-	3,300	28,582
Total		$ 479,496		$ 52,830

On May 31, 2005, 19.5 million class A common shares of the Company were issued as consideration to acquire the outstanding shares of Vaquero.

On April 5, 2005, 4.0 million class A common shares of the Company were issued pursuant to the Company's initial public offering. Costs associated with the initial public offering totalled approximately $4.8 million.

On March 31, 2005, 3.5 million class A common shares of the Company were issued upon the exercise of the special warrants.

On February 15, 2005, the Company declared a stock dividend in the amount of $7.0 million which resulted in 0.047 of a class A common share being issued for each issued and outstanding class A common share. In accordance with the terms of the issued and outstanding special warrants of the Company the stock dividend resulted in an additional 0.2 million class A common shares being issuable upon exercise of the outstanding special warrants.

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.

(c) Per share amounts:

Weighted average number of common shares outstanding	2005	2004
Basic	35,051	16,747
Dilutive effect of options	667	289
Diluted	35,718	17,036

Weighted average class A common shares outstanding have been retroactively restated to give effect to the February 15, 2005 stock dividend.

(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, 2005 and 2004:

	2005		2004	
	Class A Common shares issuable	Weighted average exercise price	Class A Common shares issuable	Weighted average exercise price
Balance, beginning of year	1,542	$ 5.26	530	$ 2.84
Granted	2,308	18.96	1,012	6.53
Exercised	(47)	(3.89)	-	-
Cancelled	(224)	(17.00)	-	-
Adjustment as a result of stock dividend	73	-	-	-
Balance, end of year	3,652	$ 13.06	1,542	$ 5.26
Exercisable, end of year	556	$ 4.33	175	$ 2.78

Details of the exercise prices and expiry dates of options outstanding at December 31, 2005 are as follows:

	Options outstanding			Options exercisable	
Range of exercise price	Class A Common shares issuable	Weighted average years to expiry	Weighted average exercise price	Class A Common shares issuable	Weighted average exercise price
$ 2.60 - $5.00	1,110	3.77	$ 3.73	447	$ 3.33
$ 8.10 - $14.00	598	4.99	$ 9.92	109	$ 8.43
$18.00 - $21.35	1,944	5.51	$ 19.36	-	-
	3,652	4.89	$ 13.06	556	$ 4.33

Anti-dilutive options excluded from the calculation of diluted earnings per share were 232,000 (2004 – nil).

The fair value of stock options granted during the year ended December 31, 2005 and December 31, 2004 was estimated using the Black-Scholes option pricing model with the following assumptions:

	2005	2004
Expected volatility	45%	50%
Risk free rate of return	4.5%	4.5%
Expected option life	4 years	4 years
Weighted average fair market value per option	$ 7.43	$ 3.48

The Company does not anticipate paying any dividends during the expected life of the options.

(e) Contributed surplus:

	2005	2004
Balance, beginning of year	$ 511	$ 115
Stock based compensation expense	3,151	396
Transferred on exercise of stock options	(35)	-
Balance, end of year	$ 3,627	$ 511

12 COMMITMENTS:

The Company is committed to operating leases for office space and equipment annually as follows:

2006	$ 1,261
2007	1,196
2008	1,158
2009	1,210
2010	1,210
Thereafter	2,320

13 FINANCIAL INSTRUMENTS:

(a) Commodity price risk management:

The following financial instrument contracts were outstanding at December 31, 2005:

Financial WTI crude oil contracts

Term	Contract	Volume (bbls/d)	Fixed Price/bbl	Unrealized Gain (CDN)
Jan 06 to Dec 06	Collar	2,000	US $60.00 to $69.80	540
Jan 06 to Dec 06	Collar	1,000	US $55.00 to $77.25	135

Financial AECO natural gas contract

Term	Contract	Volume (GJs/d)	Fixed Price/GJ	Unrealized Gain (CDN)
Jan 06 to Dec 06	Collar	5,000	CDN $9.00 to $14.70	763

The financial AECO natural gas contract does not qualify as an effective hedge for accounting purposes and as such, the unrealized gain has been recorded in income and as a financial instrument asset.

(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.

(c) Fair values:

The carrying values of the Company's financial assets and liabilities, with the exception of the Company's long-term investment (note 6), approximated their fair values as at December 31, 2005 and 2004. The fair value of the Company's long-term investment was considered undeterminable due to the inability to apply a valuation method or obtain market prices.

14 SUBSEQUENT EVENTS:

(a) Public offering:

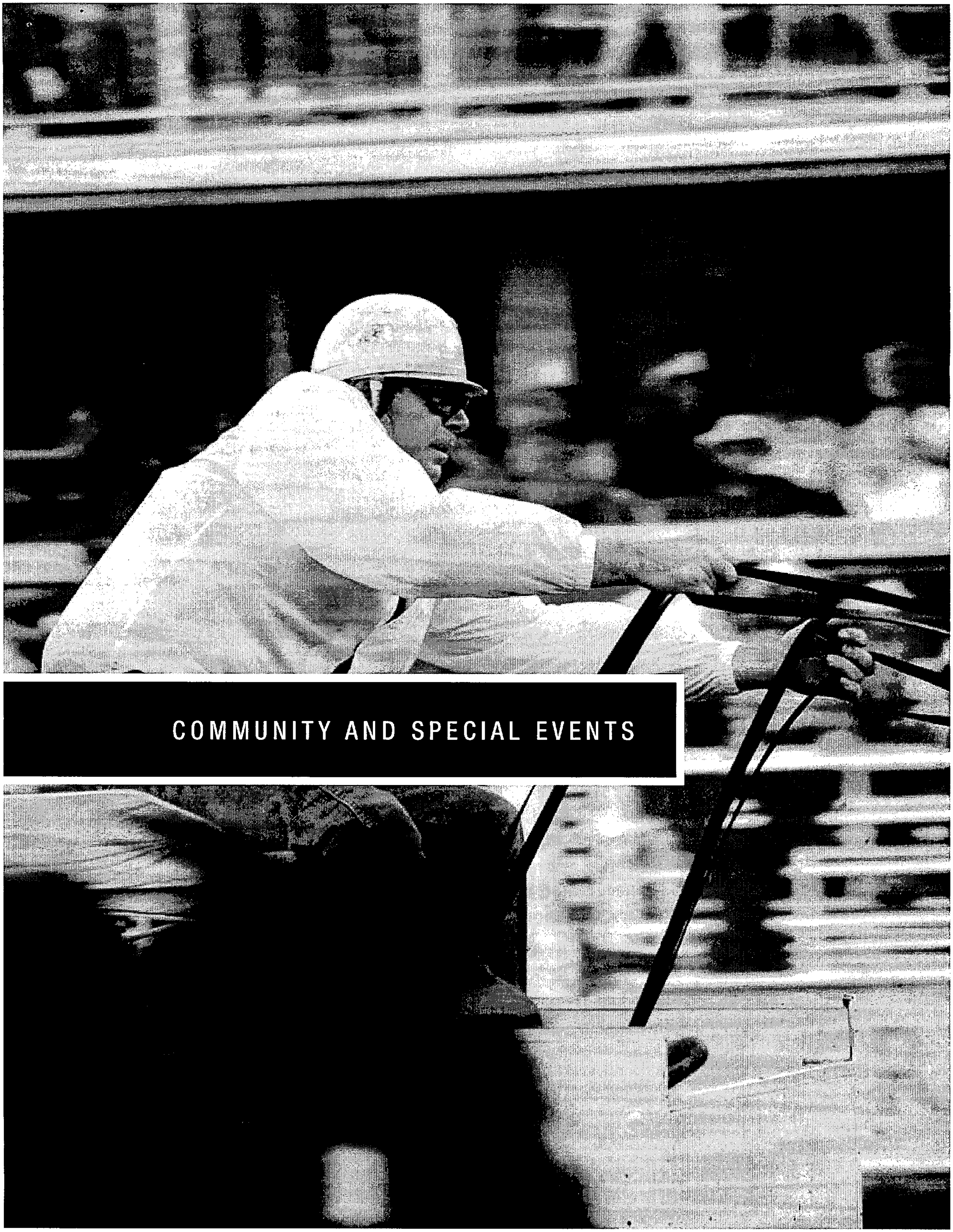
On February 23, 2006, the Company and a syndicate of underwriters closed a bought deal equity financing pursuant to which the syndicate sold 4.3 million class A common shares of the Company for gross proceeds of $100.6 million (net proceeds - $96.6 million).

(b) Acquisition of White Fire Energy Ltd.:

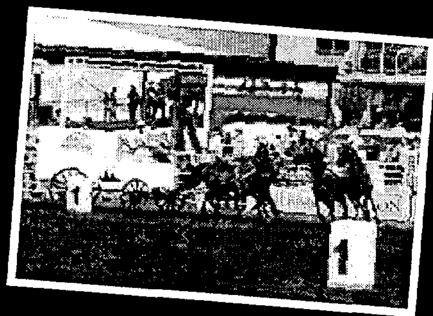
On February 21, 2006, the Company closed the previously announced acquisition of White Fire Energy Ltd. ("White Fire") by way of a Plan of Arrangement. Under the Plan of Arrangement, shareholders of White Fire received 0.132 class A common shares of the Company for each common share of White Fire held. The Company issued approximately 4.1 million class A common shares to shareholders of White Fire.

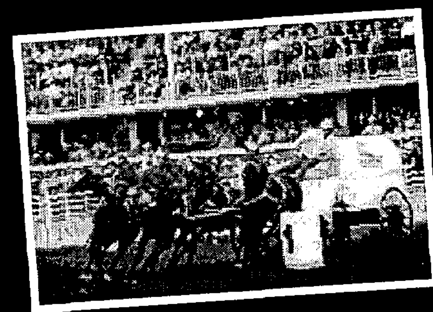
15 COMPARATIVE BALANCES:

Certain of the comparative balances have been reclassified to conform to the current year's presentation.



COMMUNITY AND SPECIAL EVENTS

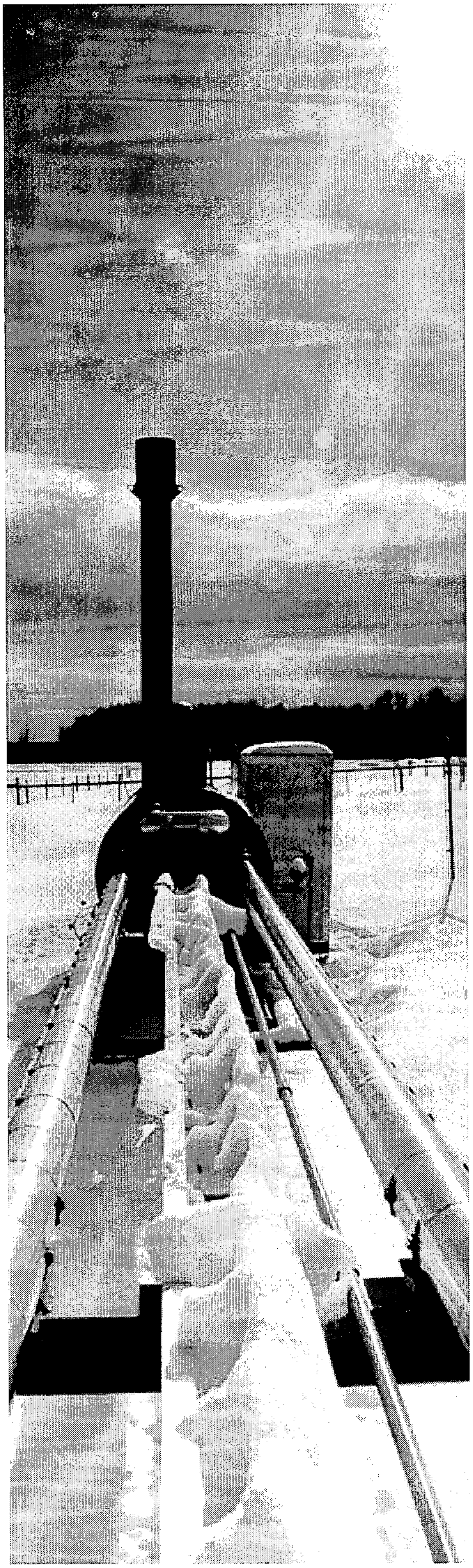




Highpine is a strong believer in being a good corporate citizen and a responsible neighbour in the community. It is necessary, conscientious and above all, rewarding.

In the Drayton Valley and Whitecourt areas, Highpine is a committed sponsor for many valuable activities and programs. This includes sponsorship of the 4H Beef Program, the Food Bank, Santa's Anonymous, several elementary school activities, as well as a platinum-level sponsorship of the Field House Recreation Centre. Donations have also been made to other charitable organizations, including the Alberta Children's Hospital and both the Canadian and American Red Cross.

Highpine also sponsors the World Professional Chuckwagon Association at the Calgary Stampede and the Ponoka Stampede. These sponsorships provide Highpine's staff - and the residents of the communities in which we work - a great opportunity to get involved with this exhilarating sport. Highpine has established this tradition as a way to support the community for years to come.



Board of Directors

John Brussa [2]
Partner
Burnet, Duckworth & Palmer, LLP

Richard Carl [1] [2] [3]
Independent Businessman

Andrew Krusen [1] [3]
President
Dominion Financial Group Inc.

A. Gordon Stollery
Chairman & CEO
Highpine Oil & Gas Limited

Hank Swartout [1] [2]
President & CEO
Precision Drilling Corporation

Robert N. Waldner
President & CEO
Vaquero Resources Ltd.

Ken Woolner [3]
Independent Businessman

[1] Member of the Audit Committee
[2] Member of the Compensation, Nominating and Corporate Governance Committee
[3] Member of the Reserves Committee

Senior Management

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Chairman & CEO

Greg Baum
President & COO

Bob Rosine
Executive Vice President, Corporate Development

Harry Cupric
Vice President, Finance & CFO

Bob Fryk
Senior Vice President, Engineering & Operations

Wayne Gray
Vice President, Land

Dave Humphreys
Vice President, Operations

Doug McArthur
Senior Vice President, Exploration

Rob Pinckston
Vice President, W5M Gas

Evaluation Engineers
Paddock, Lindstrom & Associates Ltd.

Registrar and Transfer Agent
Valiant Trust Company

Stock Listing
Toronto Stock Exchange
Symbol: HPX

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Alberta Treasury Branches

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Abbreviations

WTI	West Texas Intermediate
API	American Petroleum Institute
bbl	one stock tank barrels
mbbl	one thousand barrels
bbl/d	barrels per day
boe	barrels of oil equivalent
mboe	thousands of barrels of oil equivalent
boe/d	barrels of oil equivalent per day
NGL	natural gas liquids
mcf	one thousand standard cubic feet
mmcf	one million standard cubic feet
bcf	one billion standard cubic feet
mcf/d	one thousand standard cubic feet per day
mmcf/d	one million standard cubic feet per day
GJ	gigajoules
GJ/d	gigajoules per day
ARTC	Alberta Royalty Tax Credit

* Barrel of Oil Equivalency
A barrel of oil equivalent (boe), is derived by converting gas to oil in the ratio of six thousand cubic feet of gas to one barrel of oil, may be misleading, particularly if used in isolation.
A boe conversion is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

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