PENGROWTH ENERGY TRUST
Form 40-F
March 31, 2006

U.S. SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 40-F

o **REGISTRATION STATEMENT PURSUANT TO SECTION 12 OF THE SECURITIES EXCHANGE ACT OF 1934.**

þ **ANNUAL REPORT PURSUANT TO SECTION 13(a) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended: **December 31, 2005** Commission File Number: **1-31253**

PENGROWTH ENERGY TRUST
(Exact name of Registrant as specified in its charter)
Alberta, Canada
(Province or other jurisdiction of incorporation or organization)

1311	**None**
(Primary Standard Industrial Classification Code Number)	(I.R.S. Employer Identification Number)

Suite 2900, 240 4th Avenue S.W.
Calgary, Alberta Canada T2P 4H4
(403) 233-0224
(Address and telephone number of Registrant s principal executive offices)
Vinson & Elkins L.L.P.
2300 First City Tower, 1001 Fannin
Houston, Texas 77002-6760
(713) 758-2222
(Name, address (including zip code) and telephone number (including area code) of agent for service in the United States)
Securities registered or to be registered pursuant to Section 12(b) of the Act.

Title of each class	**Name of each exchange on which registered**
Class A Trust Units	New York Stock Exchange

Securities registered or to be registered pursuant to Section 12(g) of the Act.
None
(Title of Class)
Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act.
None
(Title of Class)

For Annual Reports indicate by check mark the information filed with this Form:

þ Annual information form þ Audited annual financial statements

Indicate the number of outstanding shares of each of the issuer s classes of capital or common stock as of the close of the period covered by the annual report:

There were 77,524,673 Class A Trust Units, of no par value, outstanding as of December 31, 2005.

Indicate by check mark whether the Registrant filing the information contained in this Form is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934 (the Exchange Act). If Yes is marked, please indicate the filing number assigned to the Registrant in connection with such Rule.

Yes o No þ

Indicate by check mark whether the Registrant (1) has filed all reports to be filed by Section 13 or 15(d) of the Exchange Act during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports) and (2) has been subject to filing requirements for the past 90 days.

Yes þ No o

DOCUMENTS FILED AS PART OF THIS ANNUAL REPORT

The following documents have been filed as part of this Annual Report on Form 40-F as Appendices hereto:

Appendix	Documents
A	Pengrowth Energy Trust Annual Information Form for the year ended December 31, 2005.
B	Management s Discussion and Analysis (included on pages 54 through 80 of the Pengrowth Energy Trust 2005 Annual Report).
C	Consolidated Financial Statements of Pengrowth Energy Trust, including note 20 thereof which includes a reconciliation of the Consolidated Financial Statements to United States generally accepted accounting principles.
D	Five Year Review Pengrowth Energy Trust Consolidated Financial Results (included on pages 115 through 119 of the Pengrowth Energy Trust 2005 Annual Report).
E	Corporate Governance (included on pages 48 through 53 of the Pengrowth Energy Trust 2005 Annual Report).
F	Oil and Gas Producing Activities Prepared in Accordance with SFAS No. 69 Disclosures about Oil and Gas Producing Activities .

CONTROLS AND PROCEDURES

As of the end of the period covered by this report, an evaluation was carried out under the supervision, and with the participation, of the Registrant s management, including the Chief Executive Officer and Chief Financial Officer, of the effectiveness of the Registrant s disclosure controls and procedures, as that term is defined in Rules 13a - 15(e) and 15d - 15(e). Based on that evaluation, the Registrant s Chief Executive Officer and Chief Financial Officer concluded that the design and operation of these disclosure controls and procedures were effective to ensure that material information required to be disclosed by the Registrant in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Commission s rules and forms.

During the fiscal year ended December 31, 2005, there were no changes in the registrant s internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, the registrant s internal control over financial reporting. It should be noted that any system of controls, however well designed and operated, can provide only reasonable, and not absolute, assurance that the objectives of the system are met. In addition, the design of any control system is based in part upon certain assumptions about the likelihood of future events. Because of these and other inherent limitations of control systems, there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions, regardless of how remote.

NOTICES PURSUANT TO REGULATION BTR

None

IDENTIFICATION OF THE AUDIT COMMITTEE

The registrant has a separately-designated standing audit committee established in accordance with Section 3(a)(58)(A) of the Exchange Act. The members of the audit committee are: Thomas A. Cumming, Kirby L. Hedrick, Michael S. Parrett and A. Terence Poole.

AUDIT COMMITTEE FINANCIAL EXPERT

The board of directors of the Registrant has determined that each of Michael S. Parrett and A. Terence Poole, members of the Registrant s audit committee, qualify as audit committee financial experts for purposes of paragraph (8) of General Instruction B to Form 40-F. The board of directors has further determined that each of Mr. Parrett and Mr. Poole is also independent, as that term is defined in the Corporate Governance Listing Standards of the New York Stock Exchange. The Commission has indicated that the designation of each of Mr. Parrett and Mr. Poole as an audit committee financial expert does not make either of them an expert for any purpose, impose any duties, obligations or liabilities on them that are greater than those imposed on members of the audit committee and the board of directors who do not carry this designation or affect the duties, obligations or liabilities of any other member of the audit committee or the board of directors.

GOVERNANCE DISCLOSURE INCORPORATED BY REFERENCE

Certain disclosure regarding the corporate governance practices of the Registrant, including disclosure of the Registrant s code of ethics, principal accountant fees and services, pre-approval policies and procedures, off-balance sheet arrangements and contractual obligations, is included on pages · through · of the Annual Information Form contained in Appendix A and incorporated herein.

UNDERTAKING

Registrant undertakes to make available, in person or by telephone, representatives to respond to inquiries made by the Commission staff, and to furnish promptly, when requested to do so by the Commission staff, information relating to: the securities registered pursuant to Form 40-F; the securities in relation to which the obligation to file an annual report on Form 40-F arises; or transactions in said securities.

SIGNATURES

Pursuant to the requirements of the Exchange Act, the Registrant certifies that it meets all of the requirements for filing on Form 40-F and has duly caused this Annual Report to be signed on its behalf by the undersigned, thereunto duly authorized.

Date: March 29, 2006

PENGROWTH ENERGY TRUST
by its Administrator
PENGROWTH CORPORATION

By: /s/ James S. Kinnear
James S. Kinnear
Chairman, President and
Chief Executive Officer

APPENDIX A
PENGROWTH ENERGY TRUST ANNUAL INFORMATION FORM FOR THE YEAR ENDED DECEMBER 31, 2005

PENGROWTH ENERGY TRUST
ANNUAL INFORMATION FORM

Pengrowth Energy Trust is an energy investment trust formed under the laws of the Province of Alberta which offers and sells its trust units to the public. The trust units are not deposits within the meaning of the Canadian Deposit Insurance Corporation Act (Canada) (CDIC Act) and are not insured under the provisions of the CDIC Act or any other legislation. Furthermore, Pengrowth Energy Trust is not a trust company and, accordingly, is not registered under any trust and loan company legislation as it does not carry on or intend to carry on the business of a trust company.

March 29, 2006

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Unless otherwise indicated, all of the information provided in this Annual Information Form is as at December 31, 2005.

GLOSSARY OF TERMS AND ABBREVIATIONS

Capitalized terms in this Annual Information Form have the meanings set forth below:

Corporate

Board of Directors refers to the board of directors of the Corporation;

Computershare refers to Computershare Trust Company of Canada;

Corporation refers to Pengrowth Corporation, the administrator of the Trust;

Pengrowth, we, us *and* ***our*** refers to the Trust and the Corporation on a consolidated basis;

Manager refers to Pengrowth Management Limited, the manager of the Trust and the Corporation;

Reclassification means the reclassification of our outstanding Trust Units as Class B Trust Units and the conversion of Class B Trust Units held by non-residents of Canada to Class A Trust Units which occurred on July 27, 2004;

Trust refers to Pengrowth Energy Trust;

Trust Units, when used in reference to any time before 5:00 p.m. Eastern Daylight Time on July 27, 2004, refers to the Trust Units of the Trust as they existed before the Reclassification, and when used in reference to any time after 5:00 p.m. Eastern Daylight Time on July 27, 2004, refers to the Class A Trust Units and the Class B Trust Units of the Trust as well as the Trust Units of the Trust that remain as they existed before the Reclassification; and

Unitholders refers to holders of Trust Units issued by the Trust.

Engineering

Company Gross Interest *or* ***Pengrowth Gross Interest*** refers to the Working Interest share of reserves prior to the deduction of interests owned by others (burdens). Company Royalty Interest reserves are not included in the Company Gross Interest reserves;

Company Net Interest *or* ***Pengrowth Net Interest*** refers to Pengrowth s Working Interest share of production or reserves, as the case may be, after the deduction of royalties and including Company Royalty Interest reserves, and, with respect to land and wells, refers to Pengrowth s Working Interest share therein;

Company Royalty Interest refers to an interest in production and payment that is based on the gross production at the wellhead. A royalty is paid in either cash or kind, but is paid on a value calculated at the wellhead;

Developed Non-Producing Reserves refers to 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;

Developed Producing Reserves refers to those reserves 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 Reserves refers to those reserves that are expected to be recovered from existing wells and facilities or, if facilities have not been installed, that would involve a low expenditure to put the reserves on production. The developed category may be subdivided into producing and non-producing;

GLJ refers to GLJ Petroleum Consultants Ltd., independent petroleum consultants, Calgary, Alberta;

GLJ Report refers to the report prepared by GLJ dated February 17, 2006, having an effective date of December 31, 2005;

Gross with respect to production and reserves refers to the total production and reserves attributable to a property before the deduction of royalties and with respect to land and wells refers to the total number of acres or wells, as the case may be, in which Pengrowth has a Working Interest or a royalty interest;

Net refers to Pengrowth s Working Interest share of production or reserves, as the case may be, after the deduction of royalties, and, with respect to land and wells, refers to Pengrowth s Working Interest share therein;

Pengrowth Company Interest is equal to Company Gross Interest plus Company Royalty Interest. That is, the Working Interest share of production or reserves prior to the deduction of interests owned by others (burdens) plus the interest in production made from gross production or reserves at the wellhead;

Pengrowth Total Proved Plus Probable Reserves means Company Interest share of the Total Proved Plus Probable Reserves;

Probable Reserves refers to those additional reserves that are less likely 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;

Proved Reserves refers to 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;

Reserve Life Index refers to the number of years determined by dividing the aggregate of the reserves of a property by the estimated production per year from such property using estimated production for the year 2006 as a reference;

Reserves refers to estimated remaining quantities of oil and natural gas and related substances anticipated to be recovered from known accumulations, from a given date forward, based on: (i) analysis of drilling, geological, geophysical and engineering data; (ii) the use of established technology; and specified economic conditions which are generally accepted as being reasonable and shall be disclosed. Reserves are classified according to the degree of certainty associated with the estimate (e.g., proved, probable);

Total Proved Plus Probable Reserves means the aggregate of Proved Reserves and Probable Reserves before the deduction of royalties;

Undeveloped Reserves refers to those reserves expected to be produced from known accumulations where a significant expenditure (e.g. the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserve classification (proved, probable) to which they are assigned;

Unitization refers to a process whereby owners of adjoining properties pool reserves into a single unit operated by one of the owners, typically in order to conduct secondary recovery projects in a manner that promotes improved recovery of reserves from a pool or field; and

Working Interest refers to the percentage of undivided interest held by Pengrowth in an oil and gas property.

Abbreviations

API means American Petroleum Institute;

bbl, bbls, mbbls, and mmbbls refers to barrel, barrels, thousands of barrels and millions of barrels, respectively;

bblpd refers to barrels per day;

boe, mboe and mmboe refers to barrels of oil equivalent, thousands of barrels of oil equivalent and millions of barrels of oil equivalent, respectively, on the basis of one boe being equal to one barrel of oil or NGLs or six mcf of natural gas; barrels of oil equivalent may be misleading, particularly if used in isolation; a conversion ratio of 6 mcf of natural gas to one boe is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead;

boepd refers to barrels of oil equivalent per day;

CBM refers to coal bed methane;

EOR refers to enhanced oil recovery;

$M and ***$MM*** refers to thousands of dollars and millions of dollars, respectively;

mmBtu and ***mmBtupd*** refers to million British thermal units and million British thermal units per day respectively;

mcf, mmcf, bcf and ***tcf*** refers to thousands of cubic feet, millions of cubic feet, billions of cubic feet and trillions of cubic feet, respectively;

mcfpd and ***mmcfpd*** refers to thousands of cubic feet per day and millions of cubic feet per day respectively;

NGLs refers to natural gas liquids;

NYSE refers to the New York Stock Exchange; and

TSX refers to the Toronto Stock Exchange.

CONVERSION

In this Annual Information Form measurements are given in Standard Imperial or metric units only. The following table sets forth certain standard conversions:

To Convert From	To	Multiply by
mcf	cubic metre	28.174
cubic metre	cubic feet	35.494
bbls	cubic metre	0.159
cubic metre	bbls	6.29
feet	metre	0.305
metre	feet	3.281
miles	kilometre	1.609
kilometre	miles	0.621
acres	hectares	0.405
hectares	acres	2.471

Unless otherwise stated, all sums of money referred to in this Annual Information Form are expressed in Canadian dollars.

PRESENTATION OF OUR FINANCIAL INFORMATION

Financial information in this Annual Information Form has been prepared in accordance with generally accepted accounting principles (GAAP) in Canada. Canadian GAAP differs in some significant respects from U.S. GAAP and thus our financial statements may not be comparable to the financial statements of U.S. companies. The principal differences as they apply to us are summarized in note 20 to the audited annual consolidated financial statements of the Trust which are available on the SEDAR website at www.sedar.com and in our Form 40-F which is available through EDGAR at the United States Securities and Exchange Commission s website at www.sec.gov.

PRESENTATION OF OUR RESERVE INFORMATION

The United States Securities and Exchange Commission (the SEC) generally permits oil and gas companies, in their filings with the SEC, to disclose only proved reserves after the deduction of royalties and interests of others which are those reserves that a company has demonstrated by actual production or conclusive formation tests to be economically producible under existing economic and operating conditions. In 2003, the securities regulatory authorities in Canada (other than Québec) adopted National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* (NI 51-101), which imposes oil and gas disclosure standards for Canadian public issuers engaged in oil and gas activities. NI 51-101 permits oil and gas issuers, in their filings with Canadian securities regulators, to disclose not only proved reserves but also probable reserves, and to disclose reserves and production on a gross basis before deducting royalties. Probable reserves are of a higher risk and are less likely to be accurately estimated or recovered than proved reserves. Because we are permitted to prepare this Annual Information Form in accordance with Canadian disclosure requirements, we have disclosed in this Annual Information Form and in the documents incorporated by reference reserves designated as probable . If this Annual Information Form was required to be prepared in accordance with U.S. disclosure requirements, the SEC s guidelines would prohibit reserves in these categories from being included. Moreover, in accordance with Canadian practice, we have determined and disclosed estimated future net cash flow from our reserves using both escalated and constant prices and costs; for the constant prices and costs case, prices and costs in effect as of December 31, 2005 were held constant for the economic life of the reserves. The SEC does not permit the disclosure of estimated future net cash flow from reserves based on escalating prices and costs and generally requires that prices and costs be held constant at levels in effect at the date of the reserve report. For a description of these and additional differences between Canadian and U.S. standards of reporting reserves (see page 66 Risk Factors Canadian and United States practices differ in reporting reserves and production). Additional information prepared in accordance with United States Statement of Financial Accounting Standards No. 69 Disclosures About Oil and Gas Producing Activities relating to our oil and gas reserves is set forth in our Form 40-F which is available through EDGAR at the SEC s website at www.sec.gov.

FORWARD-LOOKING STATEMENTS

This Annual Information Form contains forward-looking statements within the meaning of securities laws, including the safe harbour provisions of the Ontario *Securities Act* and the United States *Private Securities Litigation Reform Act of 1995*. Forward-looking information is often, but not always, identified by the use of words such as anticipate , believe , expect , plan , intend , forecast , target , project , may , will , should , could , estimate , p suggesting future outcomes or language suggesting an outlook. Forward-looking statements in this Annual Information Form include, but are not limited to, statements with respect to: business strategy and strengths, goals, focus and the effects thereof, acquisition criteria, capital expenditures, reserves, reserve life indices, estimated production, remaining producing reserve lives, net present values of future net revenue from reserves, commodity prices and costs, exchange rates, the impact of contracts for commodities, development plans and programs, tax horizon, abandonment and reclamation costs, government royalty rates and expiring acreage. Statements relating to reserves are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the reserves described exist in the quantities predicted or estimated and can profitably be produced in the future.

Forward-looking statements and information are based on Pengrowth s current beliefs as well as assumptions made by and information currently available to Pengrowth concerning anticipated financial performance, business prospects, strategies and regulatory developments. Although management considers these assumptions to be reasonable based on information currently available to it, they may prove to be incorrect.

By their very nature, forward-looking statements involve inherent risks and uncertainties, both general and specific, and risks that predictions, forecasts, projections and other forward-looking statements will not be achieved. We caution readers not to place undue reliance on these statements as a number of important factors could cause the actual results to differ materially from the beliefs, plans, objectives, expectations and anticipations, estimates and intentions expressed in such forward-looking statements. These factors include, but are not limited to: the volatility of oil and gas prices; production and development costs and capital expenditures; the imprecision of reserve estimates and estimates of recoverable quantities of oil, natural gas and liquids; Pengrowth s ability to replace and expand oil and gas reserves; environmental claims and liabilities; incorrect assessments of value when making acquisitions; increases in debt service charges; the loss of key personnel; the marketability of production; defaults by third party operators; unforeseen title defects; fluctuations in foreign currency and exchange rates; inadequate insurance coverage; compliance with environmental laws and regulations; changes in tax laws; the failure to qualify as a mutual fund trust; and Pengrowth s ability to access external sources of debt and equity capital. Further information regarding these factors may be found under the heading Business Risks in our management s discussion and analysis for the year ended December 31, 2005 and under Risk Factors herein.

Pengrowth cautions that the foregoing list of factors that may affect future results is not exhaustive. When relying on our forward-looking statements to make decisions with respect to Pengrowth, investors and others should carefully consider the foregoing factors and other uncertainties and potential events. Furthermore, the forward-looking statements contained in this Annual Information Form are made as of the date of this Annual Information Form and Pengrowth does not undertake any obligation to up-date publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained in this Annual Information Form are expressly qualified by this cautionary statement.

PENGROWTH ENERGY TRUST

The Trust is an oil and gas royalty trust that was created under the laws of the Province of Alberta on December 2, 1988. The Trust is governed by a trust indenture dated July 27, 2004 (amending and restating the trust indenture dated June 17, 2003 and subject to further amendments authorized by Unitholders on April 26, 2005), between the Corporation and Computershare, as trustee. In 1996, the Trust s original name, Pengrowth Gas Income Fund , was changed to Pengrowth Energy Trust . The purpose of the Trust is to purchase and hold royalty units issued by the Corporation, its majority owned subsidiary, and to issue Trust Units to members of the public. The Corporation acquires, owns and manages Working Interests and royalty interests in oil and natural gas properties as well as oil and gas processing facilities. The beneficiaries of the Trust are the Unitholders.

The Corporation was created under the laws of the Province of Alberta on December 30, 1987. In 1998, the name of the Corporation was changed from Pengrowth Gas Corporation to Pengrowth Corporation . The Corporation has 1,100 common shares outstanding, 1,000 of which are owned by the Trust and 100 of which are owned by the Manager. The Corporation has its head and registered offices at 2900, 240 4th Avenue S.W., Calgary, AB T2P 4H4.

The Manager was created under the laws of the Province of Alberta on December 16, 1982 as Pengrowth Management Limited. The Manager serves as the manager of the Trust and as the manager of the Corporation.

GENERAL DEVELOPMENT OF PENGROWTH TRUST

Organization and Structure

Under the royalty indenture between the Corporation and Computershare, as trustee, the Corporation has granted a royalty consisting of a 99 percent share of royalty income to the holders of royalty units. The royalty units represent fractional undivided interests in the royalty.

Under the trust indenture between the Corporation and Computershare, as trustee, the Trust has issued Trust Units to the Unitholders. Each Trust Unit represents a fractional undivided beneficial interest in the Trust. Our Unitholders are entitled to receive monthly distributions in respect of the royalty and in respect of investments that are held directly by us.

The Trust presently holds approximately 99.9 percent of the royalty units issued by the Corporation. In addition, the Trust holds other permitted investments, such as oil and gas processing facilities, debt obligations of the Corporation and its affiliates and cash.

The Corporation directly and indirectly acquires, owns and operates Working Interests and royalty interests in oil and natural gas properties. The Corporation has issued royalty units which entitle the holders thereof to receive a 99 percent share of the royalty income (on page 48) related to the oil and natural gas interests of the Corporation. The Corporation owns all of the issued and outstanding shares of Stellar Resources Limited (Stellar), a corporation incorporated under the laws of the Province of Alberta. Stellar holds a 0.01 percent partnership interest in three partnerships, Pengrowth Heavy Oil Partnership, Pengrowth Energy Partnership and Crispin Energy Partnership and acts as the general partner of the partnerships. The remaining 99.99 percent partnership interest in each of the partnerships is held by the Corporation. Pengrowth Heavy Oil Partnership and Pengrowth Energy Partnership were acquired in connection with the acquisition of certain properties from Murphy. Crispin Energy Partnership was acquired during 2005 in connection with the acquisition of Crispin Energy Inc. (Crispin).

Pursuant to the unanimous shareholder agreement dated June 17, 2003 (amending and restating the unanimous shareholder agreement dated April 23, 2002 and subject to amendments authorized by Unitholders on April 22, 2004 and April 26, 2005) among the Manager, the Trust, the Corporation and Computershare, our Unitholders and holders of royalty units (other than Computershare) are entitled to notice of, and to attend, all meetings of shareholders of the Corporation and vote as shareholders at all meetings of the shareholders of the Corporation to the same extent as if they were holders of common shares of the Corporation in respect of all matters upon which the *Business*

Corporations Act (Alberta) requires a shareholder vote including voting on the election of the directors of the Corporation (other than the two directors to be appointed by the Manager), appointing its auditors and appointing the auditor of the Trust. In addition, our Unitholders are entitled to vote on any proposed amendment to the unanimous shareholder agreement.

The principal business of the Manager is that of a specialty fund manager. The Manager currently provides advisory, management, and administrative services to the Trust and to the Corporation. In particular, the Manager also manages and provides services relating to the acquisition and disposition of oil and natural gas properties and other related assets on behalf of the Corporation. James S. Kinnear, President and a director of Pengrowth Management and Chairman, President, Chief Executive Officer and a director of the Corporation, owns, directly or indirectly, all of the issued and outstanding voting securities of the Manager.

The following chart illustrates the organization and structure of Pengrowth:

Note:

(1) These properties were acquired on May 31, 2004 in an acquisition from Murphy Oil which had interests in oil and natural gas assets in Alberta and

(2) These properties were acquired on April29, 2005 in the acquisition of Crispin.

Business Strategy and Strengths

Our goal is to maximize cash distributions on a per Trust Unit basis to our Unitholders over time while enhancing the value of our Trust Units. We engage in limited exploration for oil and natural gas. Instead, we focus on making accretive acquisitions, adding reserves and production through development drilling, and maximizing the value of our mature property base by reducing operating costs, implementing new development technologies, such as tertiary recovery operations, and implementing other operational efficiencies.

Our ability to pay out distributions while enhancing Unitholder value over time is dependent upon effective operations and investments, and our ability to make acquisitions which yield returns that exceed our cost of capital. We evaluate acquisition opportunities based upon the following acquisition criteria:

Financial

Acquisitions should increase future distributions on a per Trust Unit basis based upon current economics.

The undiscounted aggregate projected future net cash flow from the properties should exceed the aggregate purchase price of the properties and provide a reasonable rate of return.

The oil and gas producing properties to be acquired should, in the context of the market, have an attractive rate of return.

Operational

Properties to be acquired should be high quality, relatively long life and proven producing properties. The Corporation gives priority to properties with:

- low anticipated capital expenditures relative to the cash generation potential of the properties;
- relatively low operating costs or high netbacks;
- experienced, well regarded industry operators or where operatorship may be assumed by Pengrowth;
- favourable production history;
- upside potential through infill drilling, improved field operations and other development activities;
- relatively long reserve life;
- potential synergies with our current properties and areas of our core expertise; and
- low environmental and site remediation risk.

Independent Verification

Each purchase of new properties will be based on an independent engineering report except for properties where the purchase price is less than $5 million.

Our structure, tax effectiveness and cost of capital allow us to bid competitively for oil and natural gas properties relative to taxable corporations and other taxable entities. Opportunities to acquire oil and gas properties generally arise from sellers looking to reduce indebtedness, seeking funds for higher risk exploration and development activities, exiting the business, or fulfilling other strategic objectives.

Historical Development

The Corporation s first acquisition, in December of 1988, was the purchase of a 2.6507 percent Working Interest in Dunvegan Gas Unit No. 1 located near Fairview, Alberta in the Peace River Arch. The Corporation financed the acquisition by issuing 1,250,000 royalty units at a price of $10.00 per royalty unit, substantially all of which were issued to the Trust. The Trust issued 1,243,500 Trust Units to the public at a price of $10.00 per Trust Unit for gross proceeds of $12,435,000 which were used to pay for the royalty units. An additional 56,500 royalty units were also issued in the public offering. Of these additional royalty units, 18,240 royalty units were outstanding as of December 31, 2005.

Commencing in 1991, the Manager adopted a plan, and established criteria, to build Unitholder value through accretive acquisitions and financings of those acquisitions. Thereafter the Corporation completed a series of acquisitions that were financed through periodic issuances of Trust Units, rights offerings and bank indebtedness.

The Trust commenced a series of fully marketed equity offerings in 1994 to fund various property acquisitions. Since that time the Corporation has continued a course of targeted asset acquisitions for cash. The most significant purchases and financings are described below.

Effective July 1, 1997, the Corporation acquired a 98.11 percent Working Interest in the Judy Creek Beaverhill Lake Unit, a 94.58 percent Working Interest in the Judy Creek West Beaverhill Lake Unit and a 9.58 percent Working Interest in Swan Hills Unit No. 1 for a net purchase price of $496.1 million. In November 1997, the Corporation increased its Working Interest in the Judy Creek Beaverhill Lake Unit to 100 percent.

On October 15, 1997, the Trust completed an offering of 23,928,572 Trust Units on an installment receipt basis with $12.50 per Trust Unit paid on closing and the balance of $8.75 per unit due on or before October 15, 1998. Gross proceeds raised amounted to $508 million comprised of cash of $299 million and an installment receivable of $209 million. On April 15, 1998, the Corporation assumed operatorship of the Judy Creek Units from Imperial Oil Resources Ltd. Effective October 15, 1998, the Trust acquired certain facilities interests related to operations in the Judy Creek and Swan Hills areas from the Corporation for consideration of $106 million. The Trust entered into an agreement to lease the facilities back to the Corporation.

On November 10, 2000, the Trust issued 8,165,000 Trust Units to raise gross proceeds of $155,135,000 which were applied to acquire interests in Goose River, House Mountain, Minnehik Buck Lake, Mitsue and Weyburn from Canadian Natural Resources Limited for cash consideration of $128 million and the transfer of certain properties.

On May 31, 2001, the Trust issued 10,895,000 Trust Units to raise gross proceeds of $225.5 million.

Effective June 15, 2001, the Corporation acquired a royalty representing substantially all of the beneficial interest in the natural gas and liquids production from an 8.4 percent Working Interest in the Sable Offshore Energy Project (SOEP) from Nova Scotia Resources (Ventures) Limited (NSRVL) for $265 million (net adjusted price of $228.4 million). On December 24, 2001, the Corporation acquired certain additional petroleum and natural gas rights and other assets from NSRVL for a gross purchase price of $27.5 million. On May 7, 2003, the Corporation acquired an 8.4 percent Working Interest in the four SOEP production facilities downstream of Thebaud Central Platform from SOEP co-venturers ExxonMobil Canada Properties, Shell Canada Resources Limited, Imperial Oil Resources Ltd. and Mosbacher Operating Company Ltd. for net consideration of approximately $57 million. In May 2003 Pengrowth entered into an agreement with Nova Scotia Resources Limited (NSRL) to purchase varying interests in eleven Significant Discovery Licenses (SDLs) for $4.5 million plus a 10 percent Net Profit Interest to NSRL. In December 2003 Pengrowth acquired from Emera Offshore Incorporated (and its subsidiaries, associates and affiliates on a consolidated basis) (Emera) their 8.4 percent interest in the SOEP offshore production platforms facilities for $65 million. As a result of the foregoing transactions, the Corporation holds an undivided 8.4 percent Working Interest in SOEP.

On June 4, 2002, the Trust issued 8,000,000 Trust Units at a price of $15.40 per Trust Unit for total gross proceeds of $123.2 million.

On October 1, 2002, with an effective date of July 1, 2002, the Corporation acquired certain properties located in northeast British Columbia from Calpine Natural Gas Partnership for net consideration after adjustments of $352 million.

In November, 2002, the Trust completed a cross-border equity offering in Canada and the United States of 20,125,000 Trust Units at $14.00 per Trust Unit (U.S. $8.93 per unit) for gross proceeds of approximately

$281.8 million. In total, two public Trust Unit offerings completed during 2002 raised $380 million in net equity proceeds.

On April 23, 2003, Pengrowth completed a U.S. $200 million private placement of senior unsecured notes to a group of U.S. investors. The notes were offered in two tranches: U.S. $150 million at 4.93 percent due April 23, 2010 and U.S. $50 million at 5.47 percent due April 23, 2013. Interest on the notes is payable semi-annually.

On March 23, 2004, the Trust completed an equity offering of 10,900,000 Trust Units, including 2,700,000 Trust Units issued upon exercise of an underwriters option, at a price of $18.40 per Trust Unit for gross proceeds of $200.5 million.

On May 31, 2004 the Corporation acquired certain properties from Murphy Oil Corporation (the Murphy Properties) for $551 million. The Murphy Properties represent a diverse group of assets within western Canada, encompassing interests in the West Central Alberta and Peace River areas (including interests in the McLeod and Deep Basin areas); Southern Alberta (including interests in the Countess, Princess and Twining/Three Hills areas); and heavy oil (including interests in the Lindbergh, Tangleflags and Bodo/Cactus areas). The properties also include 219,000 acres of undeveloped land.

On July 27, 2004 Pengrowth implemented the Reclassification whereby the existing outstanding Trust Units were reclassified into Class B Trust Units and the Class B Trust Units held by non-residents of Canada were converted into Class A Trust Units (with the exception of Trust Units held by holders who did not provide a residency declaration to Computershare which remained unchanged pending receipt of a suitable residency declaration).

On August 12, 2004 Pengrowth acquired an additional 34.35 percent Working Interest in the company operated Kaybob Notikewin Gas Unit, adding approximately 2 mmboe of proved plus probable reserves for $20 million before adjustments. The acquisition increased Pengrowth s Working Interest in the unit to 99 percent.

On December 30, 2004, the Trust completed an equity offering of 15,985,000 Class B Trust Units, including 5,285,000 Class B Trust Units issued upon exercise of an underwriters option and an over-allotment option, at a price of $18.70 per Class B Trust Unit for gross proceeds of $298.9 million.

On February 28, 2005, Pengrowth closed the acquisition of an additional 11.89 percent Working Interest in Swan Hills Unit No. 1 increasing Pengrowth s total Working Interest in the unit to 22.34 percent. The purchase price was $87 million, after adjustments from the October 1, 2004 effective date to the closing date.

On April 29, 2005, pursuant to a Plan of Arrangement under the *Business Corporations Act* (Alberta), Pengrowth completed the acquisition of Crispin which held interests in oil and natural gas assets including CBM assets mainly in Alberta. Pengrowth issued 3,538,581 Class B Trust Units and 686,732 Class A Trust Units valued at $88 million in exchange for all outstanding shares of Crispin.

On December 1, 2005, Pengrowth completed a £50 million private placement of senior unsecured 10 year notes with a group of U.K. based investors. In a related transaction, Pengrowth entered into a series of currency swaps to hedge the foreign exchange risk and fixed the effective coupon rate of the notes at 5.49 percent.

On January 12, 2006, Pengrowth announced transactions with Monterey Exploration Ltd. (Monterey) under which Pengrowth sold approximately 1,000 boepd of non-core production for $22 million cash and 8 million shares in Monterey and farmed out acreage in northeast British Columbia under terms that include our ability to participate in exploration activities in conjunction with Monterey. As at March 24, 2006, Pengrowth holds approximately 34 percent of the common shares of Monterey.

Since the formation of Pengrowth in 1988, Pengrowth has completed a total of 18 public equity financings for gross proceeds of approximately $2.3 billion.

Recent Acquisitions, Financings and Developments

2006 Forecast Capital, Production and Operating Costs

On November 29, 2005, the Board of Directors of the Corporation approved Pengrowth s 2006 Capital Expenditure Program of up to $236 million. Pengrowth will continue to develop the Judy Creek miscible flood program through a combination of infill drilling and new horizontal injection wells. In northeast British Columbia, Pengrowth will focus on new gas wells and further development of existing waterflood programs. Pengrowth also anticipates an additional well being drilled and increased compression being installed at SOEP. Several drilling opportunities in both heavy oil and shallow gas in Southern Alberta are anticipated to be completed in 2006.

Pengrowth expects to fund the 2006 Capital Expenditures Program through a combination of undistributed cash from operations, unused credit facilities, dividend reinvestment program proceeds rights and options proceeds and any proceeds from property dispositions.

The table below describes the forecasted capital, production and operating costs for 2006:

PLANNED CAPITAL EXPENDITURES	$ MILLIONS	% OF TOTAL
Drilling expenditures	131	56
Facilities and maintenance	64	27
Land and seismic	21	9
Recompletions and workovers	12	5
Other	8	3
TOTAL	236	100

Average daily production volume (boepd)	54,000 - 56,000(1)
Operating costs per boe	$ 11.00(2)

Notes:

1. After the divestiture of approximately 1,300 boepd of production in the first quarter of 2006 comprised of volumes associated with previously disclosed purchase and sale agreements, as well as the divestment of approximately 1,000 boepd of production related to the Monterey transactions announced on January 12, 2006. The 2006 estimate excludes potential additions through acquisition.

2. Assuming the production targets for 2006 are achieved.

Borrowing and Note Payable

The Corporation has a $370 million revolving unsecured credit facility syndicated among eight financial institutions with an extendible 364 day revolving period and a three year amortization term period. The revolving credit facility will revolve until June 16, 2006, whereupon it may be renewed for a further 364 days, subject to satisfactory review by the lenders, or converted into a term facility. If converted to a term facility, one third of the amount outstanding would be repaid in equal quarterly instalments in each of the first two years with the final one third to be repaid upon maturity of the term period. In addition, the Corporation has a $35 million demand operating line of credit. As of March 24, 2006, an aggregate of $11 million was drawn on these facilities which are also reduced by outstanding letters of credit in the amount of approximately $17 million. In addition, a note payable is due to Emera in respect to the acquisition of the SOEP facilities. The note is secured by Pengrowth s Working Interest in SOEP. It is a non-interest bearing note with the final $20 million payment due on December 31, 2006.

U.K. 10 Year Term Notes

On December 1, 2005, Pengrowth completed a £50 million private placement of senior unsecured 10 year notes to a group of U.K. based investors. In a related transaction, Pengrowth entered into a series of currency swaps to hedge the foreign exchange risk and fixed the effective coupon rate of the notes at 5.49 percent. We enter into term loans from time to time to diversity our sources of debt and to stagger repayment over time.

Crispin Acquisition

On April 29, 2005, pursuant to a Plan of Arrangement under the *Business Corporations Act* (Alberta) Pengrowth completed the acquisition of Crispin which held interests in oil and natural gas assets mainly in Alberta. Pengrowth issued 3,538,581 Class B Trust Units and 686,732 Class A Trust Units valued at $88 million in exchange for all of the outstanding shares of Crispin.

Monterey Transaction

On January 12, 2006, Pengrowth announced certain transactions with Monterey under which Pengrowth sold approximately 1,000 boepd of production for $22 million of cash and 8 million shares in Monterey and farmed out acreage in northeast British Columbia under terms that include our ability to participate in exploration activities in conjunction with Monterey. As at March 24, 2006, Pengrowth holds approximately 34 percent of the common shares of Monterey.

Monterey has agreed to drill a minimum of 20 exploration wells and pay 100 percent of the costs to earn a 75 percent interest in the farmed out lands.

Formation of Special Committee to Examine Dual Class Structure

On March 23, 2006 the Trust received a letter from the Department of Finance (Canada) confirming that it remains the intention of the Department of Finance to recommend to the Minister of Finance the changes to the *Tax Act* contained in the comfort letter the Department provided to the Trust dated November 26, 2004. The Department of Finance undertook therein to recommend to the Minister of Finance that an amendment be made to the Property Test (as defined herein) that would clarify the Trust s ability to rely upon that test and effectively remove any significant risk regarding the status of the Trust as a mutual fund trust.

On March 27, 2006 Pengrowth announced the formation of a special committee of the Board of Directors to make recommendations to the Board of Directors. The mandate of the special committee includes examining alternatives to that structure including the removal of the restriction from the Class B Trust Units, the merger of the Class A Trust Units and the Class B Trust Units into a single class of Trust Units or any other alternatives the committee considers appropriate.

For added information see page 43 Trust Units Trust Unit Reclassification Background .

Trends

There are a number of business and economic factors which underlie trends in the oil and gas industry that influence the near term future of our business.

The conversion of traditional oil and gas companies into income and royalty trusts continued in 2005. The proliferation of income and royalty trusts, the efforts of these trusts to replace annual production declines, robust oil and natural gas prices and low interest rates have resulted in a very competitive market for the acquisition of oil and gas properties and related assets. There has been a corresponding increase in the valuation parameters for corporate and asset acquisitions, while at the same time income and royalty trusts, including the Trust, have enjoyed favourable access to equity and debt capital markets.

Many Canadian royalty trusts, including Pengrowth, have increased their capital spending on development drilling opportunities and limited exploration prospects in order to replace production. Pengrowth engaged a highly qualified operations team including retaining three new vice presidents in 2005 in the areas of operations, geosciences and strategic planning and reservoir exploitation. We have developed areas of core competency that include EOR, shallow gas, heavy oil and CBM. In recent transactions with Murphy and Crispin, we have enhanced our undeveloped land position. As a result we have an opportunity to add reserves less expensively through development than through the current acquisition market. Thus, expanded development drilling programs have become more important to Pengrowth.

Commodity prices, while volatile, are at high levels compared with historical averages. However, the appreciation of the Canadian dollar in 2005 relative to the U.S. dollar has offset a portion of the economic benefit to Canadian oil and gas producers, including trusts, of these higher prices. Increases or decreases in the Canadian dollar relative to the U.S. dollar also result in decreases or increases, respectively, in net revenue as the main markets for our oil and gas are priced in U.S. dollars or based on pricing linked to U.S. dollars and operating costs are denominated in Canadian dollars. The Canadian dollar has continued its strength into 2006.

For additional information regarding the Trust s strategy in this business environment, see Management s Discussion and Analysis Outlook on page 78 of the Trust s Annual Report for the year ended December 31, 2005.

PENGROWTH MANAGEMENT LIMITED

Business

The principal business of Pengrowth Management is to provide advisory, management, and administrative services primarily to the Trust and the Corporation. The Manager also previously provided investment advisory and management services in relation to investments by several Canadian pension funds in the energy sector. These investments were subsequently acquired by the Corporation for royalty units and cash. The Manager utilizes its extensive experience and employs prudent oil and gas business practices to increase the value of the assets of the Corporation through effective acquisitions and dispositions and through effective operations. The Manager has focused upon high quality, long life proven producing properties located in Canada. The Manager will continue to focus upon acquisitions which are strategic and which add value to the Corporation and the Trust on a per Trust Unit basis.

Management Agreement

The Unitholders and the holders of royalty units approved an amended and restated management agreement among the Trust, the Corporation, the Manager and Computershare, as trustee (the Management Agreement) at annual and special meetings held on June 17, 2003. The Management Agreement governs both the Trust and the Corporation. The Board of Directors negotiated the Management Agreement with the Manager, to incentivize future performance and to avoid the upfront termination payments associated with internalizations of management.

Key elements of the Management Agreement are:

- two distinct 3-year terms with a declining fee structure in the second 3-year term;

- a base fee determined on a sliding scale:
  - o in the first three-year contract term:
    - § 2 percent of the first $200 million of Income; and
    - § 1 percent of the balance of Income over $200 million; and
  - o in the second three-year contract term:
    - § 1.5 percent of the first $200 million of Income; and
    - § 0.5 percent of the balance of Income over $200 million.

For these purposes, Income means the aggregate of net production revenue of the Corporation and any other income earned from permitted investments of the Trust (excluding interest on cash or near-cash deposits or similar investments).

- a performance based fee based on total returns received by Unitholders which essentially compensates the Manager for total annual returns which average in excess of 8 percent per annum over a 3-year period;

a ceiling on total fees payable determined in reference to a percentage of the fees paid under the previous management agreement: 80 percent each year in the first three-year contract term and 60 percent each year in the second three-year contract term and subject to a further ceiling essentially equivalent to $12 million annually during the second three-year contract term;

requirement for the Manager to pay certain expenses of the Corporation and the Trust of approximately $2 million per year;

an annual minimum management fee of $3.6 million comprised of $1.6 million of management fees and $2.0 million of expenses;

key man provisions in respect of James S. Kinnear, the President of the Manager;

an annual bonus pool based on 10 percent of the Manager s base fee and performance fee for employees of, and special consultants to, the Corporation; and

an optional buyout of the Management Agreement at the election of the Board of Directors upon the expiry of the first three-year contract term with a termination payment of approximately 2/3 of the management fee paid during the first three-year contract term plus expenses of termination.

The responsibilities of the Manager under the Management Agreement include:

reviewing and negotiating acquisitions for the Corporation and the Trust;

providing written reports to the Board of Directors to keep the Corporation fully informed about the acquisition, exploration, development, operation and disposition of properties, the marketing of petroleum substances, risk management practices and forecasts as to market conditions;

supervising the Corporation in connection with it acting as operator of certain of its properties;

arranging for, and negotiating on behalf of, and in the name of, the Corporation all contracts with third parties for the proper management and operation of the properties of the Corporation;

supervising, training and providing leadership to the employees and consultants of the Corporation and assisting in recruitment of key employees of the Corporation;

arranging for professional services for the Corporation and the Trust;

arranging for borrowings by the Corporation and equity issuances by the Trust; and

conducting general Unitholder services, including investor relations, maintaining regulatory compliance, providing information to Unitholders in respect of material changes in the business of the Corporation or the Trust and all other reports required by law, and calling, holding and distributing material in respect of meetings of Unitholders and holders of royalty units.

Despite the broad authority of the Manager, approval of the Board of Directors is required on decisions relating to any offerings, including the issuance of additional Trust Units, acquisitions in excess of $5 million, annual operating and capital expenditure budgets, the establishment of credit facilities, the determination of cash distributions paid to Unitholders, the compensation practices, specific compensation programs for certain key executives of the Corporation, the amendment of any of the constating documents of the Corporation or the Trust and the amount of the assumed expenses of the Manager which are a portion of the compensation of the Manager.

Management Fee

Management fees are calculated on a percentage of net operating income (oil and gas sales and other income, less royalties, operating costs, solvent amortization and reclamation funding.) The base fee has been reduced from a sliding scale between 3.5 percent and 2.5 percent, to the new rate of 2 percent on the first $200 million of net operating income and 1 percent on net operating income over $200 million. Acquisition fees were eliminated (effective July 1, 2003), and the Manager is eligible to receive a performance fee if certain performance criteria are met. The previous fee arrangements remain relevant however as there is a cap imposed on the fees, including the performance fee, limiting the aggregate of such fees to 80 percent of the fees that would otherwise have been paid under the old management agreement (inclusive of acquisition fees) for the first three years, and 60 percent for the second three years.

Bonus Pool

As an incentive to officers, employees and special consultants of the Manager (including employees of the Corporation but excluding the President, James S. Kinnear), an annual bonus pool has been established which is carved out from the management fee paid to the Manager, determined as 10 percent of the total fees received by the Manager (i.e. 10 percent of the management fee and any performance fee earned). Bonuses are paid from time to time in accordance with criteria recommended by the Manager as a further incentive for top performing employees.

Management Agreement Second Term

Under the terms of the Management Agreement, the Corporation had the right to terminate the Management Agreement effective June 30, 2006 on payment to the Manager of a termination fee and certain other amounts. In the absence of such termination, the Management Agreement continues in effect for a final three year term ending June 30, 2009.

An Independent Committee of the Board of Directors of the Corporation was constituted for the purpose of considering a termination of the Management Agreement. The Committee retained Scotia Capital Inc. as its financial advisor. After considering the anticipated effects to the Corporation and to the Unitholder value of both a termination of the Management Agreement and a continuation of the Management Agreement, the Committee recommended to the full Board of Directors that the Management Agreement not be terminated at the end of the first term.

The Committee based its recommendation on several factors including:

- The amount of the termination fee payable to the Manager on termination of the Management Agreement effective June 30, 2006;

- The estimated cost of internal management to June 30, 2009 in the event of a termination of the Management Agreement effective June 30, 2006;

- The estimated maximum management fees that would be payable to the Manager over the final three years of the term of the Management Agreement;

- The advice of its financial advisor;

- The fee ceiling applicable during the final three years of the Management Agreement which will result in lower management fees in the second term of the Management Agreement ending June 30, 2009 as compared to the first term of the Management Agreement ending June 30, 2006; and

- The commitment by the Manager to certain key governance standards relating to the conduct of the affairs of the Trust and a continuing commitment to overall corporate governance practices (as such practices would apply to Pengrowth in an internalized management structure); and a further commitment to assist and work with the Board in establishing a plan for the orderly transition to a traditional corporate management structure at the end of the final term of the Management Agreement on June 30, 2009.

Based on the recommendation of the Independent Committee, the Board of Directors resolved not to terminate the Management Agreement at the end of the first term and has therefore resolved to continue the Management Agreement in accordance with its terms for a second three year term ending on June 30, 2009.

PENGROWTH CORPORATION   OPERATIONAL INFORMATION

As at December 31, 2005, the Corporation had 303 permanent employees. The Corporation has invested more than $3 billion in the energy sector primarily to purchase mature, proven producing oil and natural gas properties in Canada.

Principal Properties

The portfolio of properties acquired and held by the Corporation primarily includes relatively long life, oil and gas producing properties with established production profiles.

The Corporation obtained the GLJ Report dated February 17, 2006 in respect to the oil and gas properties of the Corporation effective December 31, 2005. All reserve data presented under this sub-heading is based on the GLJ Report.

The Corporation s producing properties are summarized in the following table:

Summary of Property Interests Held by Pengrowth Corporation as at December 31, 2005[3]
Forecast Prices and Costs

	Remaining Reserve Life (Years)	Reserve Life Index (Years)	Company Interest Total Proved Plus Probable Reserves[2] (Mboe)	Value at 10% Discount ($million)	2005 Actual Oil Equivalent Production[2] (boepd)
Judy Creek BHL Unit	50	11.9	36,820	538.1	8,847
Swan Hills Unit No.1	50	21.1	19,903	196.5	2,481
Weyburn Unit	50	18.6	19,253	186.1	2,649
SOEP	11	5.7	15,241	346.1	7,075
Judy Creek West BHL Unit	50	23.1	9,160	81.1	1,415
Monogram Gas Unit	36	8.7	6,265	120.6	2,517
McLeod River	50	7.3	5,480	92.5	2,321
East Bodo	50	28.3	5,252	31.5	542
Dunvegan Gas Unit No. 1	39	9.3	5,154	72.6	1,442
Twining	45	10.3	4,390	63.9	1,360
Kaybob Notikewin Unit No. 1	40	12.8	4,366	53.6	1,048
Tangleflags	18	6.8	4,344	22.8	1,806
Oak	50	10.9	4,030	70.4	1,014
Quirk Creek	35	11.9	3,574	42.7	807
Princess	50	9.0	3,556	65.1	796
Enchant	50	15.3	3,270	37.1	684
Rigel	21	6.7	3,150	73.4	1,625
Other[1]	50	8.9	66,188	1,110.4	20,928
Total	50	10.5	219,396	3,204.5	59,357

Notes:

1. Other includes the Corporation s working and royalty interest in approximately 100 other properties. 2. Natural gas has been converted to barrels of oil equivalent on the basis of six mcf of natural gas being equal to one boe.

3. The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

Judy Creek Beaverhill Lake Unit and Judy Creek West Beaverhill Lake Unit

The Corporation holds a 100 percent Working Interest in both the Judy Creek Beaverhill Lake Unit (the Judy Creek A Pool) and the Judy Creek West Beaverhill Lake Unit (the Judy Creek B Pool), (together, Judy Creek). Judy Creek is located approximately 200 kilometres northwest of Edmonton in north-central Alberta and covers an area of approximately 155 square kilometres (60 sections). Judy Creek was discovered in 1959, placed on waterflood (secondary recovery) in 1962 and miscible flood (tertiary recovery) in 1985. Original-oil-in-place totaled 815 mmbbls in the Judy Creek A Pool, making it one of the largest oil pools discovered in western Canada. To December 31, 2005, a total of 353 mmbbls (gross) have been produced from the Judy Creek A Pool. Remaining Total Proved Plus Probable Reserves at December 31, 2005 are estimated at 36.8 mmboe. Original-oil-in-place at the Judy Creek B Pool totaled 262 mmbbls, and at December 31, 2005, 115 mmbbls (gross) have been produced.

The remaining producing reserve life is 50 years and the Reserve Life Index is 11.9 and 23.1 years, respectively for the A and B pools. Pengrowth s Company Interest production for Judy Creek averaged 10,262 boepd in 2005.

Development Activity

The Corporation operates both the Judy Creek A and B Pools, which are produced using both waterflood and the EOR program that was initiated in 1985. In the Judy Creek hydrocarbon miscible flood, oil production is increased by injecting a hydrocarbon-based solvent (mostly natural gas and ethane) into the reservoir. In 2005, solvent was injected at 11 miscible patterns with anticipated increased oil production from up to 32 producing wells.

Development activity in 2005 was largely focused within the A Pool and included one horizontal solvent injection well, one produced water injector and three oil producers. Three additional drilling locations from the 2005 program were delayed until the first quarter of 2006. The horizontal solvent injector pattern is a follow-up to a similar pattern developed in 2001 which has to date recovered over 750 mbbls of oil.

Drilling and related activities such as well workovers and conversions resulted in the development of four new solvent patterns and one new waterflood pattern in 2005. Six new solvent patterns will be developed in 2006. During 2005 significant upgrades were completed on the Judy Creek A Pool produced water injection system. These proactive upgrades improve the integrity of the system and reduce the potential for line failures and spills. Development plans in 2006 include drilling up to ten new oil wells, three injection wells and eleven gas wells targeting shallow natural gas reservoirs. Other methods of enhancing future production in Judy Creek are being investigated including the use of CO_2 as a solvent.

Natural gas production may also be possible through development of the CBM on Pengrowth s acreage. Pengrowth entered into an agreement with a prominent CBM company for the farmout of a portion of Pengrowth s lands at Judy Creek with CBM potential. Several horizontal wells have been drilled on these lands to test the Mannville coal formations.

Swan Hills Unit No. 1

After acquiring an additional 11.89 percent Working Interest in February 2005, Pengrowth holds a 22.34 percent Working Interest in the partner-operated Swan Hills Unit No. 1 located in north central Alberta. At December 31, 2005, GLJ estimates remaining Pengrowth Company Interest Total Proved Plus Probable Reserves of 19.9 mmboe with a remaining reserve life of 50 years and a Reserve Life Index of 21.1 years. Pengrowth Company Interest production averaged 2,481 boepd in 2005 and exited the year at 2,874 boepd.

Development Activity

In 2005 seven new wells were drilled in the Phase 3 hillslide area of the Unit adding about 560 boepd (gross) to year end production. In addition to the drilling, four wells were reactivated, two wells were acid fracture stimulated and four wells were equipped with larger pumping systems collectively adding a further 750 boepd (gross) to year end production. Although no new hydrocarbon miscible flood patterns were developed in 2005, the Unit continued injecting into three existing patterns.

The 2006 development plans include drilling four new infill wells in the Phase 1 northwest area of the Unit, developing two new miscible flood injection patterns and carrying out a variety of well and pump optimization projects.

The CO_2 miscible flood pilot project has completed seven of nine scheduled injection cycles since starting up in October, 2004. Due to the limited response seen so far at the producing wells, the pilot will probably be extended for at least two additional injection cycles after the originally scheduled nine cycles are completed later in 2006.

Weyburn Unit

Pengrowth holds a 9.76 percent Working Interest in the partner-operated Weyburn Unit in southeast Saskatchewan. Medium gravity oil is produced from the Midale carbonate reservoir under waterflood and a CO_2 miscible flood enhanced recovery scheme. At December 31, 2005, GLJ estimates remaining Pengrowth Company Interest Total Proved Plus Probable Reserves of 19.3 mmboe with a remaining reserve life of 50 years and a Reserve Life Index of 18.6 years. Pengrowth Company Interest production averaged 2,649 boepd in 2005 and exited the year at 2,813 boepd.

Development Activity

A total of 53 horizontal infill/re-entry wells were drilled in 2005 adding about 7,000 boepd (gross) to year end production. Additionally, eight new CO_2 miscible flood patterns were brought on stream in 2005, bringing the number of active patterns up to 44. Ultimately, 75 patterns are expected to be developed. The Unit secured an additional 30 mmcfpd of CO_2 under a new agreement signed with the supplier in 2005 increasing the total CO_2 supply to 125 mmcfpd. The additional CO_2, scheduled to come on stream in the third quarter of 2006, will allow the Unit to expand the EOR program and should result in higher overall production and ultimate oil recovery.

Building on the success of the 2004 and 2005 infill drilling programs, an additional 40 wells are planned for 2006. The 2006 development program also includes four new CO_2 miscible flood patterns. Higher production volumes have resulted in some infrastructure bottlenecks that will be addressed in 2006; most notably, 90,000 bblpd of water injection pumping capacity will be added (on stream early 2007) and 100 mmcfpd of CO_2 recycle compression capacity will be added (on stream late 2007).

Sable Offshore Energy Project

SOEP involves the development of several natural gas fields near Sable Island which is located approximately 225 kilometres off the east coast of Nova Scotia. Raw gas from SOEP is delivered to the onshore gas plant facility at Goldboro, where the liquids are extracted and sent to the fractionation plant in Point Tupper for processing. Sales gas is transported to market via the Maritimes & Northeast Pipeline. Propane and butane is shipped by both truck and rail while condensate is transported by ship.

As of December 31, 2005, the total SOEP remaining gross Total Proved Plus Probable Reserves are estimated by GLJ to be 841.0 bcf of natural gas and 41.3 mmbbls of NGLs and Pengrowth Company Interest Total Proved Plus Probable Reserves are estimated to be 70.6 bcf of natural gas and 3.5 mmbbls of NGLs. Pengrowth s Working Interest is 8.4 percent in SOEP. The Pengrowth Company Interest production averaged 32.1 mmcfpd of sales gas and 1,722 bblpd of NGLs and condensate in 2005.

Development Activity

A significant portion of Pengrowth s capital expenditures on partner-operated properties was invested at SOEP in 2005 with the addition of three new wells. The South Venture 2 well was drilled in 2004 and completed in 2005 while the South Venture 3 and Venture 7 wells were both drilled and completed in 2005.

Capital was also spent on the construction of a 30,000 HP compression project which will be installed at Thebaud in 2006. As of December 31, 2005, fabrication of the compression facilities was approximately 75 percent complete. The compression project involves the fabrication of an additional platform and topsides that will be installed beside the Thebaud platform and connected to Thebaud by a bridge. Installation of the platform and topsides will occur in mid 2006 with start-up scheduled for late 2006. Compression will allow the SOEP fields to be drawn down to much lower pressures allowing for a higher recovery of gas at higher production rates.

Monogram Gas Unit

Pengrowth holds a 53.8 percent Working Interest in the partner-operated Monogram Gas Unit located in southern Alberta. The Monogram Gas Unit produces sweet, dry natural gas from the Medicine Hat, Milk River and Second White Specks formations. At December 31, 2005, GLJ estimates remaining Pengrowth Company Interest Total

Proved Plus Probable Reserves at 6.3 mmboe with a remaining reserve life of 36 years and a Reserve Life Index of 8.7 years. Pengrowth Company Interest production averaged 2,517 boepd in 2005 from 520 wells.

Development Activity

A successful infill drilling program in 2004 consisted of 154 wells and effectively downspaced the unit to eight wells per section. New field and central compression was added, along with main line looping to reduce back pressure on the existing wells. No development drilling occurred in 2005. In 2006, a 20 well refracture program will determine if the original well completions effectively opened all perforated intervals. A 10 well perforation/fracture stimulation program will determine if non-unitized formations contain pay that was by-passed. This could result in the unitization of additional formations within the Unit area. These initiatives, if successful, would add additional reserves and would be incorporated into a potential 100 well infill drilling program that would commence late in 2006.

McLeod River

The McLeod River property is located approximately 110 kilometres west of Edmonton. Production is obtained from the Rock Creek, Gething, Notikewin and Cardium formations.

At December 31, 2005, GLJ estimated remaining Pengrowth Company Interest Total Proved Plus Probable Reserves of 5.8 mmboe with a remaining reserve life of 50 years and a Reserve Life Index of 7.3 years. Pengrowth Company Interest production averaged 2,321 boepd in 2005.

Development Activity

McLeod River activity will consist of a minor drilling program. Future activity will include facility consolidation.

Bodo/Cactus Lake/Plover

The Bodo, Cactus and Plover heavy oil properties were purchased in the Murphy acquisition and straddle the Alberta-Saskatchewan border. The properties produce mainly 12° API oil from the McLaren and 15° API oil from the Lloydminster reservoirs. The fields have several batteries to treat oil to pipeline specification, as well as a number of compressor stations to process solution and non-associated gas. An active waterflood is underway in East Bodo Lloydminster sands. At December 31, 2005, GLJ estimated remaining Pengrowth Company Interest Total Proved Plus Probable Reserves of 13.1 mmboe with a remaining reserve life of 50 years and a Reserve Life Index of 8.9 years. Pengrowth Company Interest production averaged 4,330 boepd in 2005.

Pengrowth continues to review uphole gas potential on the acquired lands and has successfully added processing volumes in existing facilities by aggressively pursuing third party opportunities.

Development Activity

East Bodo was an active area in 2005 with three new drills. Four producers will be converted to injectors in the first quarter of 2006. These will increase the level of pressure support to the waterflood. Additionally, a polymer injection skid was commissioned in December 2005 for use in a pilot. Polymer will be used to enhance the waterflood with the potential to add significant incremental waterflood recovery. An additional nine horizontal wells are planned for the third quarter of 2006 in East Bodo (Alberta) and Cosine (Saskatchewan) which are in the same trend. One vertical well was drilled and cased in Cosine in the fourth quarter of 2005.

In South Bodo, a five well horizontal infill drilling program is planned for late in the second quarter of 2006 based on the success of the 2004 program. Three of these wells will be drilled closer to the water-oil-contact to take advantage of gravity drainage to increase the current recovery factor for the pool.

Three to five horizontal wells are planned for late in the fourth quarter of 2006 in Cactus Lake (Saskatchewan) which is the same channel trend as South Bodo (Alberta). A vertical step out well was drilled in late 2005 and cased for two gas horizons in the Plover area. This could also lead to further development.

The Company is actively pursuing various EOR technologies to maximize value. These include Alkaline Surfactant Flooding, Polymer Flooding, Toe to Heel Waterflooding, Solvent Flooding and Steam Assisted Gravity Drainage (SAGD).

Dunvegan Gas Unit No. 1

Pengrowth holds a 7.97 percent Working Interest in Dunvegan Gas Unit No. 1 located 430 kilometres northwest of Edmonton, Alberta in the Peace River area. The partner-operated Dunvegan natural gas field has approximately 180 producing wells and covers an area of 213 square kilometres. Approximately 95 percent of the Unit s identified natural gas reserves are contained in the Mississippian Debolt formation. At December 31, 2005, GLJ estimates remaining Pengrowth Company Interest Total Proved Plus Probable Reserves of 5.2 mmboe with a remaining reserve life of 39 years and a Reserve Life Index of 9.3 years. In 2005, Pengrowth Company Interest production averaged 1,442 boepd.

Development Activity

A successful infill drilling program that was first initiated in 2003 continued in 2005 with the drilling of 26 additional wells. Although 15 of the new wells remained to be tied-in at year end, results indicated an average production rate exceeding 1 mmcfpd and 1 bcf of gross Reserves per well. Based on the success of this infill program, an additional 23 wells are planned for 2006.

Twining

The Twining Field is located approximately 160 kilometres northeast of Calgary. The primary producing zone is the Pekisko with additional production from the Ellerslie, Glauconite and Belly River zones. At December 31, 2005, GLJ estimated remaining Pengrowth Company Interest Total Proved Plus Probable Reserves of 4.4 mmboe with a remaining reserve life of 45 years and a Reserve Life Index of 10.3 years. Pengrowth Company Interest production from the Twining Field averaged 1,360 boepd during 2005.

Pengrowth operates over 100 wells and four main battery facilities in the Twining area. The company also operates the Equity Gas Unit No. 1 and has Working Interests in four partner-operated units.

Development Activity

Since acquiring Murphy s interests in the Twining area, Pengrowth has been evaluating potential drilling locations. A 3-D seismic program in the first quarter of 2005 helped identify locations for drilling which is expected to start in the second quarter of 2006.

Pengrowth is also monitoring CBM activity in the area including an existing program operated by MGV Energy Inc. on Pengrowth lands under a farmout agreement initiated by Murphy. Pengrowth (via the Murphy acquisition) receives a non-convertible royalty from the Twining Horseshoe Canyon farmout wells. Production commenced in July 2005 with peak production reaching 7.5 mmcfpd from 64 producing wells. MGV s success has provided Pengrowth the confidence to initiate development on offsetting Working Interest lands. An initial 18 well program (11 net) will commence drilling in the first quarter of 2006 with first sales occurring by the third quarter of 2006. Up to 50 additional wells could be drilled in 2006 based on continued drilling success and pooling arrangements.

Kaybob Notikewin No. 1

Kaybob Notikewin Unit No. 1 produces natural gas and natural gas liquids from the Notikewin formation. Initial production began in 1962. Pengrowth s ownership in this unit is 98.88 percent. At December 31, 2005, GLJ estimated remaining Pengrowth Company Interest Total Proved Plus Probable Reserves of 4.4 mmboe with a remaining reserve life of 40 years and a Reserve Life Index of 12.8 years.

Development Activity

No further activity has been planned for 2006 as the field has been fully developed with the current wells.

Tangleflags

Pengrowth holds a 50 percent Working Interest in the Canadian Natural Resources Limited operated Tangleflags North EOR project. Located in west central Saskatchewan, approximately 40 kilometres northeast of Lloydminster, the property produces 12° API oil mainly from the Lloydminster sands under a SAGD thermal recovery process. The EOR project area contains horizontal producing wells along with both vertical and horizontal steam injection wells and commenced operation in the late 1980 s. As steam is injected into the reservoir and oil and water is withdrawn, a steam chamber is created which expands vertically and laterally, heating the reservoir and allowing the oil to drain more easily to the horizontal producing wells located near the base of the reservoir. Ultimately, it is expected that in excess of 70 percent of the original-oil-in-place will be recovered in the EOR project area. Recovery to date is approximately 50 percent. At December 31, 2005, GLJ estimates remaining Pengrowth Company Interest Total Proved Plus Probable Reserves of 4.3 mmboe with a remaining reserve life of 18 years and a Reserve Life Index of 6.8 years. Pengrowth Company Interest production averaged 1,806 boepd in 2005.

Development Activity

Five new infill wells are planned in 2006 as well as a hillside stability study on the 9-23 steam plant that has been on-going since 2005. Optimization activities continue in an effort to maintain production and maximize recovery.

Oak

The Oak area is located in northeast British Columbia, approximately 20 kilometres north of Fort St. John. The property consists of 43 operated oil and natural gas wells, eight injection wells and seven water source wells surrounding two batteries and three natural gas compressor facilities. The Corporation also holds a 20.6 percent Working Interest in the non-operated Oak Cecil I Unit No. 1. Production is obtained from the Halfway, Cecil, Baldonnel, Cadomin and Bluesky formations. Two vertical Baldonnel gas wells were drilled in 2005 with one tied-in and the other abandoned.

The Oak C simulation modeling was completed in 2005 to optimize the waterflood performance and resulted in drilling of one infill producer. The Oak B waterflood scheme was approved in early 2004 and water injection began in July, 2004. Since that time there has been significant waterflood response.

At December 31, 2005, GLJ estimated remaining Pengrowth Company Interest Total Proved Plus Probable Reserves of 4.0 mmboe with a remaining reserve life of 50 years and a Reserve Life Index of 10.9 years. Pengrowth Company Interest production averaged 1,014 boepd in 2005.

Development Activity

An Oak area Baldonnel gas play is proceeding with three proposed drilling locations and two recompletions planned for 2006, and potential follow-up locations based on the success in 2006. An additional infill well in the Oak C pool is also under consideration.

Quirk Creek

The Corporation holds a 68 percent Working Interest in three producing Rundle Formation deep plate gas wells, a 31 percent Working Interest in 10 producing Rundle upper plate gas wells, a 25 percent Working Interest in 3 producing gas wells in Millarville and a 30.5 percent Working Interest in the Quirk Creek natural gas plant located in the Quirk Creek area of Southern Alberta, approximately 30 kilometres southwest of Calgary.

Pengrowth Company Interest production for 2005 was approximately 3.8 mmcfpd of natural gas and 174 bblpd of natural gas liquids. GLJ estimates Pengrowth Company Interest Total Proved Plus Probable Reserves at December 31, 2005 to be 3.6 mmboe, consisting of 17.0 bcf of natural gas and 0.7 mmbbls of NGLs. GLJ estimated a remaining reserve life of 35 years and a Reserve Life Index of 11.9 years. Pengrowth Company Interest production averaged 807 boepd for 2005.

Development Activity

The Corporation is participating in one development Rundle deep plate well in 2006. The operator is evaluating the opportunity for additional third party gas processing revenue in the area. Third party processing revenues in 2005 made up 18 percent of gross revenues for the property.

Princess

The Pengrowth operated Princess property in southeast Alberta covers 38 sections of land with mostly 100 percent Working Interest ownership. The field produces sweet dry gas from stacked sands within the Milk River, Medicine Hat and Second White Specks sequence. The wells are typically low volume, long life producers. The field has two compressor stations with dehydration facilities servicing approximately 230 Pengrowth wells. At December 31, 2005, GLJ estimated remaining Pengrowth Total Proved Plus Probable Reserves of 3.6 mmboe with a remaining reserve life of 50 years and a Reserve Life Index of 9.0 years. Pengrowth Company Interest production averaged 796 boepd in 2005. Pengrowth Company Interest production averaged 4.8 mmcfpd of sales gas for the year, but with new wells coming on in November, the 2005 exit rate was 7.1 mmcfpd.

Development Activity

During 2005 Pengrowth drilled 44 infill wells with 100 percent success. Pengrowth has plans to drill another 20 infill wells in 2006 to complete down-spacing to eight wells per section. Further down-spacing will be assessed based on performance.

Enchant

The Enchant property is located approximately 200 kilometres southeast of Calgary. The property consists of four operated oil pools in which the Corporation holds an average 88 percent Working Interest. These pools produce 32°API oil from the Arcs formation.

The Corporation holds a 99 percent Working Interest in the largest pools (the J and VV pool) which consist of 33 producing and 10 injection wells with treating, water handling and gas conservation located at a central battery facility. Primary production commenced in 1992 and a waterflood project was implemented in 1995. As of December 31, 2005, GLJ estimates remaining Pengrowth Company Interest Total Proved Plus Probable Reserves to be 3.3 mmboe with a remaining reserve life of 50 years and a Reserve Life Index of 15.3 years. Pengrowth Company Interest production averaged 684 boepd for 2005.

In the Enchant Arcs Unit No. 2, where the Corporation converted a well to injection in mid-2000, pressure support is now apparent and initial expected water breakthrough is being observed in the oil producers.

Development Activity

The Corporation is currently evaluating drilling up to three potential oil wells in the Arcs Unit No. 2 in 2006 to capture bypassed reserves due to water breakthrough.

Rigel

The Rigel area is located in northeast British Columbia, approximately 40 kilometres north of Fort St. John. The Corporation holds an average 60 percent Working Interest in the property. The property consists of four Cecil oil pools containing 33 oil wells, 16 injection wells and a central battery facility.

Optimization of pumping equipment is ongoing and stimulation of selected injectors will continue to optimize waterflood performance. The Rigel I and H pools are targeted for modeling and simulation work to identify opportunities to optimize the existing waterfloods. At December 31, 2005, GLJ estimated remaining Pengrowth Company Interest Total Proved Plus Probable Reserves of 3.2 mmboe with a remaining reserve life of 21 years and a Reserve Life Index of 6.7 years. Pengrowth Company Interest production averaged 1,625 boepd in 2005.

Development Activity
Three new operated wells and one partner operated well are planned for 2006. One of the operated well targets is a gas cap location resulting from concurrent gas cap production approval obtained for the Rigel H pool in 2005.
Reserves
The effective date of the information in this section is December 31, 2005 and the preparation date of the information is January 16, 2006. The information in this section is based upon an evaluation by GLJ with an effective date of December 31, 2005 contained in the GLJ Report dated February 17, 2006. The information in this section summarizes the oil, liquids and natural gas reserves of Pengrowth Corporation and the net present values of future net revenue for these reserves using GLJ s constant prices and costs and forecast prices and costs and conforms with requirements of NI 51-101. The Corporation engaged GLJ to provide an evaluation of Proved Reserves and Total Proved Plus Probable Reserves and no attempt was made to evaluate possible reserves. It is Pengrowth s practice to obtain an engineering report evaluating all of its Proved Reserves and Probable Reserves as at December 31 of each year.
All of the Corporation s reserves are in Canada in the provinces of Alberta, British Columbia, Saskatchewan and Nova Scotia (SOEP).
The following tables set forth certain information relating to the oil and natural gas reserves of the Corporation and the present value of the estimated future net cash flow associated with such reserves as at December 31, 2005. The information set forth below is derived from the GLJ Report which has been prepared in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook and the reserves definitions contained in NI 51-101 and the Canadian Oil and Gas Evaluation Handbook. The GLJ Report incorporates estimates of future well abandonment obligations but does not include estimates of remediation costs. **All evaluations of future net cash flow are stated prior to any provision for income taxes, interest costs or general and administrative costs and after the deduction of estimated future capital expenditures for wells to which reserves have been assigned. It should not be assumed that the estimated future net cash flow shown below is representative of the fair market value of the properties. There is no assurance that such price and cost assumptions will be attained and variances could be material. The recovery and estimates of 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**.
In 2003, the securities regulatory authorities in Canada (other than Québec) adopted NI 51-101 which imposed new oil and gas disclosure standards for Canadian public issuers engaged in oil and gas activities. Under the new reserve categories, reserves are 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:

a. analysis of drilling, geological, geophysical and engineering data;

b. the use of established technology; and

c. specified economic conditions.

Reserves are classified according to the degree of certainty associated with the estimates.

a. 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.

b. 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.

Reported reserves should target the following levels of certainty under a specific set of economic conditions:

at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and

at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.

A quantitative measure of the certainty levels pertaining to the estimates prepared for the various reserve categories is desirable to provide an understanding of the associated risks and uncertainties. However, the majority of reserve estimates are prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

In addition, where there are reserve and future net revenue estimates for less than Pengrowth as a whole, the estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties due to the effects of aggregation.

The Corporation is entitled to claim Alberta Royalty Credits. The Alberta Royalty Credits program is based on a price-sensitive formula linked to crude oil prices. Credits vary from a high of 75 percent of the eligible Alberta Crown Royalties for a taxation year to a maximum of $1,500,000 (75 percent of $2,000,000) when the price of oil falls below U.S. $15 per barrel, to a low of 25 percent (maximum $500,000) when the price of oil rises above U.S. $30 per barrel. Although this program may be expected and is usually assumed to continue indefinitely, the credits are not included in the GLJ forecasts.

The net cash flows estimated in the GLJ Report represent estimates of the revenues from oil and gas sales from the petroleum and natural gas properties of the Corporation together with an estimate of processing revenues less royalties (net of incentives), mineral taxes, field operating expenses and capital obligations. These net cash flows are not the same as the distributable cash reported by the Trust. The computation of distributable cash is described under the heading Distributable Cash Distributions and Taxability of Distributions in the Management s Discussion and Analysis appearing on page 67 of the Trust s Annual Report 2005. Significant factors to consider include:

a. the GLJ Report does not estimate general and administrative expenses, interest, management fees and holdbacks;

b. the GLJ Report does not estimate all abandonment or any reclamation liabilities;

c. for purposes of calculating distributable income, the Trust amortizes the cost of miscible flood injection fluids purchased from third parties over the period of expected future economic benefit arising from the injection of those fluids, which had been 30 months and was revised to 24 months for 2005 onward. The GLJ Report includes the full cost of purchased injection fluids ($34.7 million in 2005) in operating costs in the year incurred; and

d. the Corporation withholds certain amounts from distributable cash to fund capital.

In accordance with the requirements of NI 51-101, the Report on Reserves Data by Independent Qualified Reserves Evaluator in Form 51-101F2 and the Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3 are attached as Appendices A and B hereto, respectively.

SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
as of December 31, 2005
CONSTANT PRICES AND COSTS

	OIL AND GAS RESERVES								
	Light and Medium Oil			Heavy Oil			Natural Gas		
Reserves Category	**Pengrowth Company Interest (mbbls)**	**Pengrowth Gross Interest (mbbls)**	**Pengrowth Net Interest (mbbls)**	**Pengrowth Company Interest (mbbls)**	**Pengrowth Gross Interest (mbbls)**	**Pengrowth Net Interest (mbbls)**	**Pengrowth Company Interest (bcf)**	**Pengrowth Gross Interest (bcf)**	**Pengrowth Net Interest (bcf)**
Proved Reserves									
Proved Developed Producing	59,164	58,988	50,539	10,860	10,853	9,627	368.0	360.2	290.8
Proved Developed Non-Producing	368	368	311	62	62	57	24.5	24.1	18.5
Proved Undeveloped	18,761	18,748	15,574	1,673	1,673	1,402	31.2	29.3	24.2
Total Proved Reserves	78,292	78,104	66,424	12,595	12,588	11,086	423.7	413.6	333.5
Probable Reserves	21,361	21,324	17,820	3,118	3,117	2,651	94.4	91.1	72.7
Total Proved Plus Probable Reserves	99,653	99,427	84,245	15,713	15,705	13,737	518.1	504.7	406.2

	OIL AND GAS RESERVES					
	Natural Gas Liquids			Total Oil Equivalent Basis		
Reserves Category	**Pengrowth Company Interest (mbbls)**	**Pengrowth Gross Interest (mbbls)**	**Pengrowth Net Interest (mbbls)**	**Pengrowth Company Interest (mboe)**	**Pengrowth Gross Interest (mboe)**	**Pengrowth Net Interest (mboe)**
Proved Reserves						
Proved Developed Producing	13,660	13,478	9,377	145,010	143,348	118,007
Proved Developed Non-Producing	642	633	462	5,149	5,071	3,920
Proved Undeveloped	1,157	1,106	821	26,788	26,419	21,834
Total Proved Reserves	15,459	15,217	10,660	176,948	174,838	143,761
Probable Reserves	3,631	3,552	2,604	43,839	43,180	35,193
Total Proved Plus Probable Reserves	19,090	18,768	13,264	220,788	218,019	178,954

Reserves Category	**NET PRESENT VALUES OF FUTURE NET REVENUE CONSTANT PRICES AND COSTS BEFORE INCOME TAXES DISCOUNTED AT (%/YEAR)**				
	0% ($MM)	**5% ($MM)**	**10% ($MM)**	**15% ($MM)**	**20% ($MM)**
Proved Reserves					
Proved Developed Producing	4,745.1	3,568.7	2,896.0	2,460.1	2,153.1
Proved Developed Non-Producing	183.2	134.0	106.0	87.7	74.8
Proved Undeveloped	770.4	499.3	342.5	243.7	177.4
Total Proved Reserves	5,698.7	4,202.0	3,344.5	2,791.5	2,405.3
Probable Reserves	1,587.6	904.8	608.7	449.6	351.6
Total Proved Plus Probable Reserves	7,286.3	5,106.8	3,953.2	3,241.1	2,756.9

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
as of December 31, 2005
CONSTANT PRICES AND COSTS

Reserves Category	REVENUE ($MM)	ROYALTIES ($MM)	OPERATING COSTS ($MM)	CAPITAL DEVELOPMENT COSTS ($MM)	ABANDONMENT COSTS[1] ($MM)	FUTURE NET REVENUE BEFORE INCOME TAX ($MM)
Proved Reserves	10,453	1,988	2,348	318	99	5,699
Total Proved Plus Probable Reserves	13,082	2,523	2,791	379	101	7,286

Note:

1. Includes downhole abandonment cost but does not include surface reclamation costs. See page 37 Abandonment & Reclamation Costs.

FUTURE NET REVENUE
BY PRODUCTION GROUP
as of December 31, 2005
CONSTANT PRICES AND COSTS

Reserves Category	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10% yr) ($M)
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products) [1]	1,666,575
	Heavy Oil (including solution gas and other by-products)[1]	122,962
	Natural Gas (including by-products but excluding solution gas from oil wells) [2]	1,554,956

Total Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products) (1)	1,977,086
	Heavy Oil (including solution gas and other by-products) (1)	148,256
	Natural Gas (including by-products but excluding solution gas from oil wells) (2)	1,827,831

Notes:

1. NGL s associated with the production of solution gas are included as a by-product.

2. NGL s associated with the production of natural gas are included as a by-product.

**SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
as of December 31, 2005
FORECAST PRICES AND COSTS**

	OIL AND GAS RESERVES								
	Light and Medium Oil			Heavy Oil			Natural Gas		
Reserves Category	**Pengrowth Company Interest (mbbls)**	**Pengrowth Gross Interest (mbbls)**	**Pengrowth Net Interest (mbbls)**	**Pengrowth Company Interest (mbbls)**	**Pengrowth Gross Interest (mbbls)**	**Pengrowth Net Interest (mbbls)**	**Pengrowth Company Interest (bcf)**	**Pengrowth Gross Interest (bcf)**	**Pengrowth Net Interest (bcf)**
Proved Reserves									
Proved Developed Producing	58,219	58,060	49,693	10,924	10,916	9,621	366.2	358.5	289.4
Proved Developed Non-Producing	365	365	308	62	62	57	24.3	23.9	18.4
Proved Undeveloped	18,768	18,755	15,991	1,699	1,699	1,420	30.8	29.0	23.9
Total Proved Reserves	77,351	77,179	65,992	12,684	12,677	11,098	421.3	411.4	331.7
Probable Reserves	21,332	21,296	17,937	3,106	3,104	2,616	94.3	91.0	72.6
Total Proved Plus Probable Reserves	98,684	98,476	83,929	15,790	15,781	13,714	515.6	502.4	404.3

	OIL AND GAS RESERVES					
	Natural Gas Liquids			Total Oil Equivalent Basis		
Reserves Category	**Pengrowth Company Interest (mbbls)**	**Pengrowth Gross Interest (mbbls)**	**Pengrowth Net Interest (mbbls)**	**Pengrowth Company Interest (mboe)**	**Pengrowth Gross Interest (mboe)**	**Pengrowth Net Interest (mboe)**
Proved Reserves						
Proved Developed Producing	13,566	13,385	9,334	143,741	142,103	116,877
Proved Developed Non-Producing	637	628	460	5,113	5,035	3,893
Proved Undeveloped	1,139	1,088	805	26,745	26,376	22,200
Total Proved Reserves	15,342	15,101	10,600	175,599	173,513	142,970
Probable Reserves	3,643	3,564	2,617	43,797	43,138	35,276
Total Proved Plus Probable Reserves	18,985	18,665	13,218	219,396	216,652	178,246

NET PRESENT VALUES OF FUTURE NET REVENUE

Reserves Category	FORECAST PRICES AND COSTS BEFORE INCOME TAXES discounted at (%/year)				
	0% ($MM)	5% ($MM)	10% ($MM)	15% ($MM)	20% ($MM)
Proved Reserves					
Proved Developed Producing	3,676.7	2,871.1	2,401.0	2,089.9	1,865.9
Proved Developed Non-Producing	148.7	109.2	87.6	73.7	63.8
Proved Undeveloped	559.9	347.9	229.6	156.7	108.5
Total Proved Reserves	4,385.3	3,328.2	2,718.2	2,320.3	2,038.2
Probable Reserves	1,308.2	727.9	486.3	359.7	282.8
Total Proved Plus Probable Reserves	5,693.5	4,056.1	3,204.5	2,680.0	2,321.0

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
as of December 31, 2005
FORECAST PRICES AND COSTS

Reserves Category	REVENUE ($MM)	ROYALTIES ($MM)	OPERATING COSTS ($MM)	CAPITAL DEVELOPMENT COSTS ($MM)	ABANDONMENT COSTS [1] ($MM)	FUTURE NET REVENUE BEFORE INCOME TAX ($MM)
Proved Reserves	9,302	1,712	2,735	335	134	4,385
Total Proved Plus Probable Reserves	11,818	2,186	3,390	402	147	5,694

Note:

1. Includes downhole abandonment cost but does not include surface reclamation costs. See page 37 Abandonment & Reclamation Costs.

FUTURE NET REVENUE
BY PRODUCTION GROUP
as of December 31, 2005
FORECAST PRICES AND COSTS

Reserves Category	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10% yr) ($M)
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products) [1]	1,285,742
	Heavy Oil (including solution gas and other by-products) [1]	138,224
	Natural Gas (including by-products but excluding solution gas from oil wells) [2]	1,294,222

Total Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products) [1]	1,532,149
	Heavy Oil (including solution gas and other by-products)[1]	165,396
	Natural Gas (including by-products but excluding solution gas from oil wells) [2]	1,506,936

Notes:

1. NGL s associated with the production of solution gas are included as a by-product.

2. NGL s associated with the production of natural gas are included as a by-product.

SUMMARY OF PRICING ASSUMPTIONS
as of December 31, 2005
CONSTANT PRICES AND COSTS

	OIL				NATURAL GAS	NATURAL GAS LIQUIDS[1]			EXCHANGE RATE[2]
YEAR[3]	**WTI Cushing Oklahoma** ($US/bbl)	**Edmonton Par Price 40⁰ API** ($Cdn/bbl)	**Cromer Medium 29.3⁰ API** ($Cdn/bbl)	**LLB Crude Oil at Hardisty** ($Cdn/bbl)	**AECO Gas Price** ($Cdn/mmbtu)	**Propane** ($Cdn/bbl)	**Butane** ($Cdn/bbl)	**Pentanes Plus** ($Cdn/bbl)	($US/Cdn)
2005[4]	61.04	68.27	51.84	39.20	9.71	43.69	50.52	71.67	0.8577

Notes:

1. FOB Edmonton.
2. The exchange rate used to generate the benchmark reference prices in this table.
3. Information provided as at December 31, 2005.
4. This forecast represents the constant price forecast used by GLJ and is a representation of posted prices as of December 31, 2005.

SUMMARY OF PRICING
AND INFLATION RATE ASSUMPTIONS
as of January 1, 2006
FORECAST PRICES AND COSTS

OIL	NATURAL GAS	NATURAL GAS LIQUIDS[1]	INFLATION RATES[2]	EXCHANGE RATE[3]

Year	WTI Cushing Oklahoma ($US/bbl)	Edmonton Par Price 40^0 API ($Cdn/bbl)	Cromer Medium 29.3^0 API ($Cdn/bbl)	Hardisty Heavy 12^0 API ($Cdn/bbl)	AECO Gas Price ($Cdn/mmbtu)	Propane ($Cdn/bbl)	Butane ($Cdn/bbl)	Pentanes Plus ($Cdn/bbl)	(%/Year)	($US/Cdn)
2005(4)	56.60	69.11	57.07	34.14	8.58	42.55	51.41	69.45	2.20%	0.825
2006	57.00	66.25	55.75	33.25	10.60	42.50	49.00	67.00	2.00%	0.850
2007	55.00	64.00	55.25	32.75	9.25	41.00	47.25	65.25	2.00%	0.850
2008	51.00	59.25	51.25	32.50	8.00	38.00	43.75	60.50	2.00%	0.850
2009	48.00	55.75	48.25	32.50	7.50	35.75	41.25	56.75	2.00%	0.850
2010	46.50	54.00	46.75	32.00	7.20	34.50	40.00	55.00	2.00%	0.850
2011	45.00	52.25	45.25	33.50	6.90	33.50	38.75	53.25	2.00%	0.850
2012	45.00	52.25	45.25	33.50	6.90	33.50	38.75	53.25	2.00%	0.850
2013	46.00	53.25	46.00	34.00	7.05	34.00	39.50	54.25	2.00%	0.850
2014	46.75	54.25	47.00	34.75	7.20	34.75	40.25	55.25	2.00%	0.850
2015	47.75	55.50	48.00	35.25	7.40	35.50	41.00	56.50	2.00%	0.850
2016	48.75	56.50	48.75	36.00	7.55	36.25	41.75	57.75	2.00%	0.850
Thereafter	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	2.00%	0.850

Notes:

1. FOB Edmonton.
2. Inflation rates for forecasting prices and costs.
3. The exchange rates used to generate the benchmark reference prices in this table.
4. Actual average prices, inflation rate and exchange rate estimated for 2005.

RECONCILIATION OF NET RESERVES
BY PRINCIPAL PRODUCT TYPE
FORECAST PRICES AND COSTS

	LIGHT AND MEDIUM OIL			**NATURAL GAS**			**NATURAL GAS LIQUIDS**		
Factors	**Net Proved** (mbbls)	**Net Probable** (mbbls)	**Net Proved Plus Probable** (mbbls)	**Net Proved** (bcf)	**Net Probable** (bcf)	**Net Proved Plus Probable** (bcf)	**Net Proved** (mbbls)	**Net Probable** (mbbls)	**Net Proved Plus Probable** (mbbls)
December 31, 2004	63,572	16,871	80,443	341.4	74.0	415.4	10,974	2,845	13,819
Extensions				13.9	2.7	16.6	492	78	570
Improved Recovery	1,986	225	2,211	1.3	0.2	1.5	309	(116)	193
Technical Revisions	(354)	(1,107)	(1,461)	10.6	(9.6)	1.0	591	(259)	332
Discoveries				1.7	0.4	2.1	2	1	3
Acquisitions	7,769	2,183	9,952	15.2	6.1	21.3	260	73	333
Dispositions	(1,174)	(235)	(1,409)	(3.9)	(1.1)	(5.0)	(71)	(4)	(75)
Economic Factors									
Production	(5,807)		(5,807)	(48.6)		(48.6)	(1,957)		(1,957)
December 31, 2005	65,992	17,937	83,929	331.6	72.7	404.3	10,600	2,618	13,218

	HEAVY OIL			**TOTAL OIL EQUIVALENT BASIS**		
Factors	**Net Proved (mbbls)**	**Net Probable (mbbls)**	**Net Proved Plus Probable (mbbls)**	**Net Proved (mboe)**	**Net Probable (mboe)**	**Net Proved Plus Probable (mboe)**
December 31, 2004	12,733	3,065	15,798	144,171	35,114	179,298
Extensions				2,815	526	3,341
Improved Recovery	117	12	129	2,635	146	2,781
Technical Revisions	59	(471)	(412)	2,074	(3,435)	(1,370)
Discoveries	71	9	80	348	87	435
Acquisitions				10,561	3,266	13,827
Dispositions				(1,888)	(432)	(2,320)
Economic Factors						
Production	(1,882)		(1,882)	(17,746)		(17,746)
December 31, 2005	11,098	2,615	13,714	142,970	35,272	178,246

At year end 2005, the Corporation s remaining recoverable Total Proved Plus Probable Reserves were 219.4 mmboe as compared to 218.6 mmboe reported at year end 2004.

The following additional GLJ reserves reconciliation is presented for year end December 31, 2005.

PENGROWTH COMPANY INTEREST
RECONCILIATION OF RESERVES
ON TOTAL OIL EQUIVALENT BASIS
FORECAST PRICES AND COSTS

	Proved Producing Reserves (mboe)	**Total Proved Reserves** (mboe)	**Proved Plus Probable Reserves** (mboe)
December 31, 2004	142,353	175,502	218,613
Exploration and Development	2,797	4,096	4,898
Improved Recovery and Infill Drilling	7,386	3,193	3,342
Revisions	6,105	4,072	344
Acquisitions	8,964	12,699	16,697
Dispositions	(2,197)	(2,296)	(2,831)
Production	(21,667)	(21,667)	(21,667)
December 31, 2005	143,741	175,599	219,396

Significant factors on the reserves reconciliation were as follows:

The acquisition of Crispin and additional interest in Swan Hills Unit No. 1 accounted for 66 percent of the Total Proved Plus Probable Reserves added in 2005.

New reserves were added from development activity, mainly at Weyburn for infill drilling and improved recovery, West Pembina for drilling extensions and Gutah, in northeast British Columbia where reserves for the field could be booked when economics became favorable. Reserve increases in the Proved Producing category also resulted from reclassification of Proved Undeveloped reserves primarily for development drilling in the SOEP South Venture field and infill drilling in the Dunvegan Unit and Princess shallow gas properties.

Various performance related revisions were made to previous estimates resulting in a net positive change. The largest revisions to proved reserves occurred at Weyburn (+1,131 mboe), Twining (+912 mboe), McLeod River (+484 mboe), Quirk Creek (+464 mboe), SOEP (+464 mboe), Monogram (+461 mboe), Nipisi (+458 mboe), Swan Hills Unit No. 1 (-958 mboe), and Squirrel (-455 mboe).

Numerous small, non-core properties were sold in a disposition program which concluded late in 2005.

RECONCILIATION OF CHANGES IN
NET PRESENT VALUES OF FUTURE NET REVENUE
DISCOUNTED AT TEN PERCENT PER YEAR
PROVED RESERVES
CONSTANT PRICES AND COSTS

PERIOD AND FACTOR	Before Tax 2005 ($M)
Estimated Net Present Value at Beginning of Year	1,992,385
Oil and Gas Sales During the Period Net of Production Costs and Royalties (1)	(706,339)
Net Change due to Prices and Royalties Related to Forecast Production (2)	1,450,352
Change in Development Costs During the Period (3)	165,800
Change in Forecast Development Costs (4)	(139,485)
Change Resulting from Extensions, Infill Drilling and Improved Recovery (5)	126,767
Net Change Resulting from Discoveries (5)	8,094
Change Resulting from Acquisitions of Reserves (5)	195,907
Change Resulting from Dispositions of Reserves (6)	(26,035)
Accretion of Discount (7)	199,239
Net Change in Income Taxes (8)	
Change Resulting from Technical Reserves Revisions (5)	48,218
All Other Changes	29,592
Estimated Net Present Value at End of Year	3,344,494

Notes:

1. Excluding general and administrative expenses.

2. The impact of changes in prices and other economic factors on future net revenue.

3. Actual capital expenditures relating to the development and production of oil and gas reserves.

4.

The change in forecast development costs.

5. End of period net present value of the related reserves.

6. Start of period net present value of related reserves.

7. Estimated as 10 percent of the beginning of period net present value.

8. The difference between forecast income taxes at beginning of period and actual taxes for the period plus forecast income taxes at the end of period.

Additional Information Relating to Reserves Data

Undeveloped Reserves

Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production.

Proved and probable undeveloped reserves have been estimated in accordance with procedures and standards contained in the COGE Handbook. In general, undeveloped reserves are scheduled to be developed within the next two years. Much of the remaining capital scheduled beyond two years is related to the Weyburn, Judy Creek and Swan Hills EOR projects, which have staged development plans.

Proved Undeveloped Reserves

The Corporation s proved undeveloped reserves comprise roughly 15 percent of the total proved reserves on a barrel of oil equivalency basis. Pengrowth Company Interest proved undeveloped reserves of 26.7 mmboe were assigned by GLJ in accordance with NI 51-101. In general, proved undeveloped reserves were assigned to certain properties because capital commitments have been made to convert the undeveloped reserves to proved producing reserves. Proved undeveloped reserves have been primarily assigned for future miscible flood expansion and development drilling.

Judy Creek comprises roughly 25 percent of the proved undeveloped reserves. Miscible injection has resulted in an overall incremental recovery of between five and seven percent of the original-oil-in-place in this area and has been in use since 1985. Miscible flood expansion is an on-going program which is limited by the availability of injectant materials and is budgeted to continue through to 2009. Similarly, at Swan Hills, miscible flood expansion as well as some infill drilling accounts for another 22 percent of Pengrowth s proved undeveloped reserves assignments. The Swan Hills Unit reserves have a 50 year reserve life. The incremental recovery is reflected in the GLJ Report and miscible flood expansion is forecasted to continue until 2021. In the Weyburn Unit, an additional 19 percent of the proved undeveloped reserves assignment reflects the capital allocated to the CO_2 miscible flood. Working Interest partners are committed to a 15 year supply of CO_2 to further develop the flood area from the existing 44 patterns to full development with 75 patterns.

Ongoing development is scheduled in heavy oil properties where approximately seven percent of Pengrowth s Proved Undeveloped Reserves are assigned. These include waterflood expansion in East Bodo and infill drilling in South Bodo and Southeast Bodo. SOEP comprises five percent of the Pengrowth s Proved Undeveloped Reserves. The 2006 budget has allocated capital for drilling a well at Alma, potential recompletions at Venture and completing construction of compression facilities at Thebaud. Multi-well shallow gas infill programs are scheduled for 2006 and beyond at Tilley, Princess and Patricia/Dinosaur. Roughly five percent of the total Proved Undeveloped Reserves can be attributed to these projects. The Gutah, northeast British Columbia property contains about four percent of total Proved Undeveloped Reserves. Now that the economics are favourable, capital is budgeted to tie-in this gas field.

Probable Undeveloped Reserves

Probable Undeveloped Reserves were assigned by GLJ in accordance with the requirements and standards of NI 51-101 and the COGE Handbook. The Corporation s Probable Undeveloped Reserves amount to 13.8 mmboe and represent about six percent of the Total Proved Plus Probable Reserves. Probable Undeveloped Reserves are assigned for similar reasons and generally to the same properties as Proved Undeveloped Reserves, but also meet the requirements of the reserve classification to which they belong. The Corporation s largest Probable Undeveloped Reserves are distributed among certain properties as a percent of the total as follows: Weyburn Unit 22 percent, Swan Hills Unit 20 percent, Judy Creek Units 12 percent, SOEP seven percent, Bodo seven percent, Goose River Unit four percent and Gutah four percent.

Future Development Costs

The following table outlines development costs deducted in the estimation of future net revenue for each of the next five financial years and in total, undiscounted and using a discount rate of 10 percent per annum:

Reserve Category	2006(1) ($MM)	2007(1) ($MM)	2008(1) ($MM)	2009(1) ($MM)	2010(1) ($MM)	Remainder (1) ($MM)	Total(1) ($MM)	Total(2) ($MM)
Proved Reserves (Constant Prices and Costs)	109.5	62.4	40.2	23.4	14.0	68.9	318.4	246.4
Proved Reserves (Forecast Prices and Costs)	109.5	63.6	41.9	24.9	15.2	80.3	335.4	255.0
Proved & Probable Reserves (Forecast Prices and Costs)	121.1	75.3	52.0	29.9	20.1	103.4	401.8	300.2

Notes:

1. Undiscounted.

2. Discounted at 10 percent.

Commencing with the January 2003 distribution to Unitholders, a portion of cash available for distribution has been withheld to fund capital expenditures. See page 50 Distributions .

Finding, Development and Acquisition Costs

Finding and Development Costs

During 2005, Pengrowth spent $175.7 million on development and optimization activities, which added 11.4 mmboe of Proved and 8.6 mmboe of Total Proved Plus Probable Pengrowth Company Interest Reserves, including revisions. The largest additions were from infill drilling and enhanced recovery development in the Weyburn Unit CO_2 miscible flood project and drilling extensions for gas in West Pembina.

In total, Pengrowth participated in drilling 286 gross wells (94 net wells) during 2005 with a 99 percent success rate. Pengrowth continues to develop shallow gas in southeast Alberta, drilling 44 infill wells at Princess and participating in 102 wells at Tilley. Pengrowth was also active in drilling for gas in northern Alberta, participating in 35 infill wells in Dunvegan Gas Unit No. 1.

At Judy Creek, ongoing development of the hydrocarbon miscible flood projects continue to be a focus for Pengrowth. Infill drilling and miscible flood pattern development and optimization contribute to arresting declines and improving recovery.

During 2005, significant capital expenditures were made at SOEP to further exploit gas reserves. Two successful wells, South Venture 3 and Venture 7, were drilled and brought on stream. The massive compression project at Thebaud is progressing with completion anticipated in mid 2006 and start-up scheduled for late 2006.

In the southeast Saskatchewan Weyburn Unit, expansion and optimization of the partner operated CO_2 miscible flood EOR project progresses as planned. Fifty three horizontal infill wells, both new and re-entry, were drilled and facilities are being expanded to accommodate higher CO_2 injection rates.

Acquisitions and Divestitures

During 2005 Pengrowth was again active in making strategic acquisitions. Pengrowth spent $175.1 million adding 10.4 mmboe of Proved and 13.9 mmboe of Total Proved Plus Probable Pengrowth Company Interest Reserves, net of some minor dispositions of scattered non-core properties.

In February 2005, Pengrowth acquired an additional 11.89 percent Working Interest in Swan Hills Unit No. 1, increasing Pengrowth s total Working Interest in the unit to 22.34 percent. The purchase price was $87 million. The acquisition added 11.0 mmboe of Proved Plus Probable Reserves.

In April 2005, Pengrowth completed the acquisition of Crispin, adding approximately 1,900 boepd of production and 5.2 mmboe of Proved Plus Probable Reserves. The acquisition was funded through the issuance of Class A and Class B Trust Units valued at approximately $88 million. Pengrowth also assumed debt of approximately $20 million as part of the acquisition.

In 2005, Pengrowth concluded a disposition program selling non-core oil and natural gas properties with Pengrowth Company Interest Total Proved Plus Probable Reserves of 2.6 mmboe. Total disposition proceeds were $37.6 million.

Future Development Capital

If a company chooses to disclose finding and development costs, NI 51-101 requires that the calculation include changes in forecasted future development costs relating to the reserves. Future development costs reflect the amount of capital estimated by the independent evaluator that will be required to bring non-producing, undeveloped or probable reserves on stream. These forecasts of future development costs will change with time due to ongoing development activity, inflationary changes in capital costs and acquisition or disposition of assets. Pengrowth provides the calculation of finding and development costs both with and without change in future development costs.

FD&A Costs Company Interest Reserves

	Proved	Proved plus Probable
FD&A Costs Excluding Future Development Capital		
Exploration and Development Capital Expenditures $thousands	$175,700	$175,700
Exploration and Development Reserve Additions including Revisions mboe	11,361	8,591
Finding and Development Cost $/boe	$ 15.47	$ 20.45
Net Acquisition Capital $thousands	$175,100	$175,100
Net Acquisition Reserve Additions mboe	10,403	13,866
Net Acquisition Cost $/boe	$ 16.83	$ 12.63
Total Capital Expenditures including Net Acquisitions $thousands	$350,800	$350,800
Reserve Additions including Net Acquisitions mboe	21,764	22,457
Finding Development and Acquisition Cost $/boe	$ 16.12	$ 15.62
FD&A Costs Including Future Development Capital		
Exploration and Development Capital Expenditures $thousands	$175,700	$175,700
Exploration and Development Change in FDC $thousands	($ 54,931)	($ 50,749)
Exploration and Development Capital including Change in FDC $thousands	$120,769	$124,951
Exploration and Development Reserve Additions including Revisions mboe	11,361	8,591
Finding and Development Cost $/boe	$ 10.63	$ 14.54
Net Acquisition Capital $thousands	$175,100	$175,100
Net Acquisition FDC $thousands	$ 17,900	$ 24,700
Net Acquisition Capital including FDC $thousands	$193,000	$199,800
Net Acquisition Reserve Additions mboe	10,403	13,866
Net Acquisition Cost $/boe	$ 18.55	$ 14.41
Total Capital Expenditures including Net Acquisitions $thousands	$350,800	$350,800
Total Change in FDC $thousands	($ 37,031)	($ 26,049)
Total Capital including Change in FDC $thousands	$313,769	$324,751
Reserve Additions including Net Acquisitions mboe	21,764	22,457
Finding Development and Acquisition Cost including FDC $/boe	$ 14.42	$ 14.46

Other Oil and Gas Information

Oil and Gas Wells

As at December 31, 2005 Pengrowth had an interest in 5,591 gross (2,115 net) producing oil and natural gas wells and 1,187 gross (683 net) inactive wells.

	PRODUCING		NON-PRODUCING	
	Gross	Net	Gross	Net
Crude Oil Wells				
Alberta	1,293	613	408	245
British Columbia	151	106	48	44
Saskatchewan	1,078	283	193	84
Nova Scotia	0	0	0	0
Natural Gas Wells				
Alberta	2,794	943	176	48
British Columbia	146	81	65	51
Saskatchewan	40	31	83	43
Nova Scotia	18	1	0	0
Other				
Alberta [(1)]	50	42	142	103
British Columbia [(1)]	0	0	50	46
Saskatchewan [(1)]	21	15	22	19
Total	5,591	2,115	1,187	683

Note:

1. We cannot classify these wells as either oil or gas.

Properties with No Attributed Reserves

The following table sets forth the gross and net acres of unproved properties held by Pengrowth and the net area of unproved properties for which Pengrowth expects its rights to explore, develop and exploit to expire during the next year.

	UNPROVED PROPERTIES (acres)		
Location	**Gross**	**Net**	**Net Area to Expire[(1)]**
Alberta	331,085	198,471	21,013
British Columbia	301,302	139,365	17,007
Saskatchewan	55,955	44,808	1,160
Nova Scotia	0	0	0
Other	0	0	0
TOTAL	688,342	382,644	39,180

Note:

1. This acreage will expire if we take no action to continue the

term through operational or administrative actions. Taking these actions may or may not cause the land expiry to be stayed.

Unproved Properties

The expiring acreage is being evaluated and attempts will be made to continue the acreage based on current activity which is focused on exploitation of up-hole potential in existing wells.

Forward Contracts

Pengrowth sells forward a portion of its future production through a combination of fixed price sales contracts with customers and commodity swap agreements with financial counterparties. Pengrowth is utilizing financial swap contracts for these hedges.

In 2006, Pengrowth has hedged a total of 2,500 mmBtupd against NYMEX for the first quarter of 2006 at an average price of $14.56 per mmBtu. In addition, for full year 2006, Pengrowth has hedged a total of 2,370 mmBtupd at AECO at a price of $8.03 per mmBtu and 2,500 mmBtupd of SOEP production at an average price of $10.63 per mmBtu.

Pengrowth also has a fixed price sales contract for 3,886 mmBtupd at an average price of $2.24 mmBtu for 2006. The contract expires on April 30, 2009.

Pengrowth has hedged 4,000 bblpd of crude oil for 2006 at an average price of $64.08 per bbl, inclusive of foreign exchange conversion.

Abandonment & Reclamation Costs

The total future abandonment and reclamation costs are estimated by management based on Pengrowth Corporation s Working Interest in its wells and facilities, estimated costs to remediate, reclaim and abandon the wells and facilities, and the estimated costs to be incurred in future periods. GLJ s estimate of downhole abandonment costs are included in their report and therefore in their estimate of future net revenue. All other abandonment and reclamation costs are not reflected in their estimate of future net revenue. Pengrowth anticipates incurring abandonment costs on a total of 3,583 net wells.

Pengrowth has estimated the net present value (discounted at 10 percent per annum) of its total asset retirement obligations to be $146 million as at December 31, 2005, based on a total future liability (inflated at 2.0 percent per annum) of $1,041 million. These costs are anticipated to be paid over 50 years with the majority of the costs incurred between 2032 and 2054.

The following table summarizes Pengrowth s total asset retirement obligation:

FUTURE RECLAMATION, REMEDIATION, DISMANTLING AND ABANDONMENT COSTS

	2006 ($M)	**2007 ($M)**	**2008 ($M)**	**Remainder ($M)**	**Total ($M)**
Total Abandonment, Reclamation, Remediation & Dismantling	14,866	15,888	14,154	995,985	1,040,893
Discounted at 10%	14,174	13,772	11,154	107,408	146,508

Income Tax

In determining its taxable income, the Corporation deducts payments made to the Trust, effectively transferring the income tax liability to Unitholders thus reducing taxable income. Under the Corporation s current distribution policy, funds are withheld from distributable cash to fund future capital expenditures and repay debt. As a result of increased amounts being withheld to fund capital spending, the Corporation could become subject to taxation on a portion of its income in the future. This can be mitigated through various options including the issuance of additional Trust Units, increase of the tax accounts equal to capital spending, modifications to the distribution policy or changes to the corporate structure. As a result, the Corporation does not anticipate the payment of any cash income taxes in the foreseeable future.

Costs Incurred

The following table outlines property acquisition, exploration and development costs incurred during the financial year ended December 31, 2005.

NATURE OF COST	AMOUNT ($MM)
Acquisition Costs	
Proved	208.4
Unproved	18.7
Exploration Costs	0.0
Development Costs	204.0
Total	431.1

Development Activities

The following table summarizes the results of development activities during the financial year ended December 31, 2005.

	GROSS	NET
Development Wells		
Gas	209	73.7
Oil	70	15.4
Service	3	2.1
Dry	4	2.7
Total Wells	286	93.9

Production

Production Estimates

The following tables summarizes the volume of production estimated by GLJ for the year ended December 31, 2006 for all properties held on December 31, 2005 using constant and forecast prices and costs. These estimates assume certain activities take place, such as the development of Undeveloped Reserves, and that there are no dispositions. Pengrowth estimates the 2006 production, after the divestment of approximately 1,300 boepd of the production in the first quarter of 2006, to be between 54,000 and 56,000 boepd.

	PRODUCTION	
	Total Proved Constant Prices and Costs	Proved Plus Probable Forecast Prices and Costs
Light and Medium Crude Oil (bblpd)	19,799	20,420
Heavy Oil (bblpd)	4,892	5,169
Natural Gas (mcfpd)	153,257	156,194
Natural Gas Liquids (bblpd)	5,489	5,613
Oil Equivalent (boepd)	55,723	57,234

Production History

The following tables summarize certain information in respect of production, product prices received, royalties paid, operating expenses and resulting operating netbacks of Pengrowth for the periods indicated below:

	QUARTER ENDED			
	March 31, 2005	**June 30, 2005**	**September 30, 2005**	**December 31, 2005**
Light Crude Oil				
Average Daily Oil Production(1) (bblpd)	20,443	20,906	20,660	21,179
Sales Price (net of hedging gains/losses) ($/bbl)	54.42	56.44	63.95	59.40
Processing and other income ($/bbl)	0.80	1.03	1.01	0.51
Royalties ($/bbl)	(7.11)	(9.96)	(11.03)	(6.47)
Amortization of injectants ($/bbl)	(2.93)	(3.13)	(3.14)	(3.63)
Production Costs(2) ($/bbl)	(11.04)	(11.44)	(13.14)	(14.59)
Operating Netback ($/bbl)	34.14	32.94	37.65	35.22
Heavy Oil				
Average Daily Oil Production(1) (bblpd)	6,046	5,641	5,405	5,410
Sales Price (net of hedging gains/losses) ($/bbl)	24.39	30.32	47.74	31.77
Processing and other income ($/bbl)	0.99	0.49	(0.83)	0.74
Royalties ($/bbl)	(2.58)	(4.75)	(8.00)	(2.98)
Production Costs(2) ($/bbl)	(18.56)	(15.88)	(16.30)	(11.60)
Operating Netback ($/bbl)	4.24	10.18	22.61	17.93
NGLs				
Average Daily NGL Production(1) (bblpd)	6,345	5,870	5,448	6,710
Sales Price (net of hedging gains/losses) ($/bbl)	50.48	50.03	57.75	58.46
Royalties ($/bbl)	(14.07)	(14.59)	(20.57)	(21.29)
Production Costs(2) ($/bbl)	(6.88)	(9.15)	(10.13)	(10.05)
Operating Netback ($/bbl)	29.53	26.29	27.05	27.12
Natural Gas				
Average Daily Gas Production(1) (mcfpd)	157,491	153,423	164,288	168,862
Sales Price (net of hedging gains/losses) ($/mcf)	6.84	7.34	8.57	11.97
Processing and other income ($/mcf)	0.21	0.44	0.09	0.19
Royalties ($/mcf)	(1.27)	(1.34)	(1.47)	(2.62)
Production Costs(2) ($/mcf)	(1.17)	(1.25)	(1.40)	(1.50)
Operating Netback ($/mcf)	4.61	5.19	5.79	8.04

Notes:
1. Pengrowth Company Interest.
2. Includes transportation costs.

QUARTER ENDED

	March 31, 2005	June 30, 2005	September 30, 2005	December 31, 2005
Barrels of Oil Equivalent				
Average Daily Production[1] (boepd)	59,082	57,988	58,894	61,442
Sales Price (net of hedging gains/losses) ($/boe)	44.97	47.79	56.07	62.55
Processing and other income ($/boe)	0.94	1.58	0.52	0.77
Royalties ($/boe)	(7.63)	(9.08)	(10.60)	(12.02)
Amortization of injectants ($/boe)	(1.01)	(1.13)	(1.10)	(1.25)
Production Costs [2] ($/boe)	(9.57)	(9.90)	(10.95)	(11.24)
Operating Netback ($/boe)	27.70	29.26	33.94	38.81

Notes:
1. Pengrowth Company Interest.
2. Includes transportation costs.

Production History

The annual and average daily production of crude oil, natural gas and natural gas liquids of the Corporation, since December 31, 1997, is set out in the following table:

PENGROWTH COMPANY INTEREST PRODUCTION

	Light/Medium Oil		**Heavy Oil**		**Natural Gas**		**Natural Gas Liquids**		
	Annual Production	**Average Daily Production**	**Annual Production**	**Average Daily Production**	**Annual Production**	**Average Daily Production**	**Annual Production**	**Average Daily Production**	**Average Daily Total Production**
Year Ended	(mbbls)	(bblpd)	(mbbls)	(bblpd)	(mmcf)	(mcfpd)	(mbbls)	(bblpd)	(boepd)
Dec 31, 1997	2,792	7,650			18,744	51,355	677	1,856	18,140
Dec 31, 1998	6,094	16,695			21,063	57,707	1,220	3,342	29,741
Dec 31, 1999	6,413	17,570			22,445	61,494	1,433	3,927	31,821
Dec 31, 2000	6,441	17,599			25,656	70,098	1,539	4,205	33,581
Dec 31, 2001	7,200	19,726			33,494	91,764	1,919	5,258	40,320
Dec 31, 2002	7,269	19,914			40,775	111,713	1,917	5,252	43,785
Dec 31, 2003	8,518	23,337			43,742	119,842	2,089	5,722	49,033
Dec 31, 2004	7,619	20,817	1,302	3,558	52,806	144,278	1,933	5,281	53,702
Dec 31, 2005	7,591	20,799	2,052	5,623	58,786	161,056	2,224	6,093	59,357

Replacement of Properties

In the event that the Corporation determines that the sale of any of its interests in properties, and the release of the royalty there from, would be in the best interest of the Unitholders, the royalty indenture permits it to make sales without the requirement of approval of the Unitholders, provided that the aggregate properties sold in any given year total less than 25 percent of the assets of the Corporation, determined as at the date of disposition of the properties based upon an independent engineering appraisal. Any sale exceeding this threshold must be approved by an extraordinary resolution of the Unitholders.

The royalty indenture currently provides that if properties that are subject to the royalty are sold and the Corporation does not reinvest the entire net proceeds in replacement properties within the same calendar year, then the remaining net proceeds must be distributed to royalty Unitholders. This obligation of the Corporation would be subject to the rights of the lenders to the Corporation under its credit facility and operating line of credit.

At the special meeting of the royalty Unitholders to be held in 2006, management intends to propose that the requirement to distribute any net proceeds from the sale of properties that are not used to acquire replacement properties to royalty Unitholders be amended so that it is not a mandatory requirement. While management does not foresee any significant dispositions of properties by the Corporation, it is management s view that the mandatory nature of this requirement is too restrictive in that it does not permit the Corporation to retain the net proceeds from the disposition of properties where the Corporation determines that such net proceeds should be used for capital expenditures or debt repayment rather than the purchase of replacement properties. Amending this requirement so that it is not mandatory will provide the Corporation with greater financial flexibility while preserving the discretion of the Board of Directors to declare a special distribution of the net proceeds from the disposition of properties when it is desirable to do so.

An extraordinary resolution of the Trust and royalty Unitholders would be required to amend this requirement.

Borrowing

Pursuant to the royalty indenture, the Corporation is permitted to borrow funds to finance the purchase of properties or capital expenditures, to incur take-or-pay obligations and other burdens and encumbrances in respect of the properties, and to grant security on the properties in priority to the royalty to secure the borrowing of such funds. The Corporation is also permitted to borrow funds to finance purchases of other classes of assets including

partnership units and shares of companies. Repayment of debt shall be scheduled so as to minimize, to the extent possible, income tax payable by the Corporation. Debt service charges (to the extent that they exceed certain revenues of the Corporation) and taxes payable by the Corporation are deducted in computing royalty income.

In 2005, Pengrowth continued its policy of maintaining a conservative capital structure, capitalizing on opportunities to issue new debt and equity when appropriate while maintaining a stable level of per Trust Unit distributions to unit holders. At year end 2005, Pengrowth was in a strong financial position, with a long term debt-to-debt plus equity at book value ratio of 0.20. Pengrowth has $370 million in committed credit facilities, which was reduced by drawings of $35 million and $17 million in letters of credit outstanding at year end. In addition, Pengrowth has a $35 million demand operating line of credit. Pengrowth is well positioned to fund its 2006 development program and to take advantage of acquisition opportunities as they arise. At March 24, 2006, Pengrowth had $361 million available to draw from its credit facilities.

TRUST UNITS

The Trust Indenture

Trust Units are issued under the terms of the trust indenture between the Corporation and Computershare, as trustee. A maximum of 500,000,000 Trust Units may be created and issued pursuant to the trust indenture (including the Class A Trust Units, the Class B Trust Units and any Trust Units in the form in existence before the Reclassification that have not yet been reclassified as Class A Trust Units or Class B Trust Units), of which 159,864,083 Trust Units were outstanding on March 24, 2006 (comprised of 77,524,873 Class A Trust Units, 82,806,801 Class B Trust Units and 27,224 unreclassified Trust Units). Each Trust Unit represents a fractional undivided beneficial interest in the Trust.

The trust indenture, among other things, provides for the establishment of the Trust, the issue of Trust Units, the permitted investments of the Trust, the procedures respecting distributions to Unitholders, the appointment and removal of Computershare as trustee, Computershare s authority and restrictions thereon, the calling of meetings of Unitholders, the conduct of business at such meetings, notice provisions, the form of Trust Unit certificates and the termination of the Trust. The trust indenture may be amended from time to time. Most amendments to the trust indenture, including the early termination of the Trust and the sale or transfer of the property of the Trust as an entirety or substantially as an entirety, require approval by an extraordinary resolution of the Unitholders. An extraordinary resolution of the Unitholders requires the approval of not less than 66 2/3 percent of the votes cast by Unitholders at a meeting of Unitholders held in accordance with the trust indenture at which two or more holders of at least 5 percent of the aggregate number of Trust Units then outstanding are represented. Computershare, as trustee, is permitted to amend the trust indenture without the consent or approval of the Unitholders for certain purposes, including: (i) ensuring that the Trust complies with applicable laws or government requirements, including satisfaction of certain provisions of the *Income Tax Act* (Canada) (the *Tax Act*); (ii) ensuring that additional protection is provided for the interests of Unitholders as Computershare may consider expedient; and (iii) making typographical or other non-substantive changes that are not adverse to the interests of Computershare or Unitholders.

The Trustee

Computershare, as trustee, is generally empowered by the trust indenture to exercise any and all rights and powers that could be exercised by the owner of the assets of the Trust. Computershare s specific responsibilities include, but are not limited to, the following: (i) reviewing and accepting subscriptions for Trust Units and issuing Trust Units subscribed for; (ii) subscribing for royalty units; (iii) issuing Trust Units in exchange for royalty units tendered to it for exchange; and (iv) maintaining records and providing timely reports to Unitholders. Computershare is authorized to delegate its powers and duties as trustee except as prohibited by law.

Computershare, as trustee, must exercise its powers and carry out its functions under the trust indenture honestly, in good faith and in the best interests of the Trust and the Unitholders, and must exercise that degree of care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances. Computershare is not required to devote its entire time to the business and affairs of the Trust.

Computershare, as trustee, shall be reappointed or replaced every two years as may be determined by a majority of the votes cast at an annual meeting of the Trust Unitholders. Computershare may resign upon 60 days notice to the Corporation. Computershare may be removed by extraordinary resolution of the Trust Unitholders or by the Corporation in certain specific circumstances. Such resignation or removal shall become effective upon the acceptance of appointment by a successor.

Redemption Right

Trust Units are redeemable by Computershare, as trustee, at the request of a Unitholder when properly endorsed for transfer and when accompanied by a duly completed and properly executed notice requesting redemption at a redemption price equal to the lesser of: (i) 95 percent of the average closing price of the Class B Trust Units on the ten days after the Trust Units are surrendered for redemption and (ii) the closing price of the Class B Trust Units on the date the Trust Units are surrendered for redemption. The redemption right permits Unitholders in the aggregate to redeem Trust Units for maximum proceeds of $25,000 in any calendar month provided that such limitation may be waived at the discretion of the board of directors of the Corporation. Redemptions in excess of the cash limit must be satisfied by way of a distribution in specie of a pro rata share of royalty units and other assets, excluding facilities, pipelines or other assets associated with oil and natural gas production, which are held by the Trust at the time the Trust Units are to be redeemed. Following the Reclassification, the price of Trust Units for redemption purposes is based upon the closing trading price of the Class B Trust Units irrespective of whether the Trust Units being redeemed are Class A Trust Units or Class B Trust Units.

Voting at Meetings of Pengrowth Trust

Meetings of Unitholders may be called on 21 days notice and may be called at any time by Computershare, as trustee, or upon written request of Unitholders holding in the aggregate not less than 5 percent of the Trust Units, and shall be called by Computershare and held annually. All activities necessary to organize any such meeting will be undertaken by the Corporation on behalf of Computershare. At all meetings of the Unitholders, each holder is entitled to one vote in respect of each Trust Unit held. Unitholders may attend and vote at all meetings of the Unitholders either in person or by proxy and a proxy holder need not be a Unitholder. Two persons present in person either holding personally or representing as proxies at least 5 percent of the outstanding Trust Units constitute a quorum for the transaction of business at all such meetings. Except as otherwise provided in the trust indenture, matters requiring the approval of the Unitholders must be approved by extraordinary resolution.

Unitholders are entitled to pass resolutions that will bind Computershare, as trustee, with respect to a limited list of matters, including but, not limited to, the following: (i) the removal or appointment of Computershare as trustee; (ii) the removal or appointment of the auditor of the Trust; (iii) the amendment of the trust indenture; (iv) the approval of subdivisions or consolidations of Trust Units; (v) the sale of the assets of the Trust as an entirety or substantially as an entirety; and (vi) termination of the Trust.

Unitholders can also consider the appointment of an inspector to investigate whether Computershare has performed its duties arising under the trust indenture. Such an inspector shall be appointed if a resolution approving the appointment of such inspector is passed by a majority of the votes duly cast at a meeting held for that purpose.

Voting at Meetings of Pengrowth Corporation

The Unitholders, along with holders of royalty units other than Computershare, as trustee, are entitled to voting rights at meetings of shareholders of the Corporation on the basis of one vote for each Trust Unit (or royalty Unit) held in respect of all matters upon which the *Business Corporations Act* (Alberta) requires a shareholder vote.

Termination of Pengrowth Trust

The Unitholders may vote to terminate the Trust at any meeting of the Unitholders, subject to the following:

a. a vote may be held only if requested in writing by the holders of not less than 25 percent of the Trust Units, or if the Trust Units have become ineligible for investment by RRSPs, RRIFs, RESPs and DPSPs;

b. the termination must be approved by extraordinary resolution of the Unitholders; and

c. a quorum representing five percent of the issued and outstanding Trust Units must be present or represented by proxy at the meeting at which the vote is taken.

If the Unitholders approve termination, Computershare, as trustee, will sell the assets of the Trust, discharge all known liabilities and obligations, and distribute the remaining assets to the Unitholders. Computershare will distribute directly to the Unitholders any assets which Computershare is unable to sell by the date set for termination.

Unitholder Limited Liability

The trust indenture, provides that no Unitholder will be subject to any personal liability in connection with the Trust or its obligations and affairs, and the satisfaction of claims of any nature arising out of or in connection therewith is only to be made out of the Trust s assets. Additionally, the trust indenture states that no Unitholder is liable to indemnify or reimburse Computershare for any liabilities incurred by Computershare with respect to any taxes payable by or liabilities incurred by the Trust or Computershare, and all such liabilities will be enforceable only against, and will be satisfied only out of, the Trust s assets. It is intended that the operations of the Trust will be conducted, upon the advice of counsel, in such a way and in such jurisdictions as to avoid as far as possible any material risk of liability on the Unitholders for claims against the Trust. Legislation has been enacted in Alberta which reduces the risk to Unitholders from the legal uncertainties regarding the potential liability of Unitholders. See page 68 Risk Factors The Limited Liability of the Trust s Unitholders is Uncertain .

Special Voting Unit

In addition to the Trust Units, the Trust may issue the special voting Trust Unit which entitles the holder thereof to a number of votes equal to the number of outstanding exchangeable shares of the Corporation at any meeting of the Unitholders. The special voting Trust Unit is not entitled to receive distributions from the Trust. The special voting Trust Unit is intended to provide voting rights to the holders of exchangeable shares of the Corporation equivalent to the voting rights attached to Trust Units. As of the date hereof, the special voting Trust Unit has not been issued.

Trust Unit Reclassification

On July 27, 2004 Pengrowth implemented the Reclassification whereby the existing outstanding Trust Units were reclassified into Class B Trust Units and the Class B Trust Units held by non-residents of Canada were converted into Class A Trust Units (with the exception of Trust Units held by holders who did not provide a residency declaration to Computershare which remained unchanged pending receipt of a suitable residency declaration).

Background

Maintaining its status as a mutual fund trust under the *Tax Act* is of fundamental importance to the Trust. The consequences of the loss of this status are described under Risk Factors . If the Trust ceases to qualify as a mutual fund trust it will adversely affect the value of the Trust Units.

Generally speaking, in addition to several other requirements, in order for a trust such as the Trust to be a mutual fund trust under the *Tax Act* it must satisfy one of two tests. The first test is a benefit test that requires that the trust must not be established or maintained primarily for the benefit of non-residents of Canada (which is generally interpreted to mean that the majority of units must be held by residents of Canada) (the Benefit Test). The second test is a property test that requires that, at all times after February 21, 1990, all or substantially all of the trust s property consist of property other than taxable Canadian property (the Property Exception).

Early in 2004 it had become apparent that the level of non-resident ownership of the Trust had risen from approximately 8% at the time of listing on the New York Stock Exchange in April 2002 to a level approaching 50%.

The level of non-resident ownership rose further to approximately 56% by the date of the implementation of the Reclassification.

Pengrowth is aware that many of its competitors have significantly greater than 50% non-resident ownership and are relying on the Property Exception to maintain their mutual fund trust status. However, for reasons that may be unique to the Trust, it was not clear that the Trust could rely upon Property Exception, as a sale and leaseback transaction the Trust entered into with the Corporation in 1998 regarding certain facilities at Judy Creek may have resulted in the Trust s taxable Canadian property exceeding the threshold required by the Property Test. As a result of this uncertainty, the Board of Directors recommended that Reclassification to enable the Trust to manage the level of non-resident ownership on an ongoing basis.

In addition, the Federal Budget tabled by the Minister of Finance on March 23, 2004 proposed several changes to Subsection 132(7) of the *Tax Act* to the effect that the Property Exception would generally no longer be available to royalty trusts after December 31, 2004, subject to certain grandfathering provisions that would extend that date until December 31, 2006.

On April 22, 2004, the Trust sought and obtained the approval of its Unitholders for the Reclassification to enable the Trust to satisfy the Benefit Test by providing a mechanism to ensure that the majority of Trust Units would be held by residents of Canada. The Reclassification was implemented by the Trust on July 27, 2004 and requires that the Class A Trust Units constitute not more than 49.75% of the outstanding Trust Units of the Trust and that all of the Class B Trust Units be held by residents of Canada, to ensure that the Trust would satisfy the Benefit Test. The Trust received an advance tax ruling from the Canada Revenue Agency on July 26, 2004 and an amended ruling on December 1, 2004 that confirmed that the Trust would continue to be a mutual fund trust if the Class A Trust Units constituted less than the ownership threshold of 49.75% by June 1, 2005 and the Trust was a mutual fund trust prior to that date.

As at December 31, 2004, the Class A Trust Units represented 50.2% of the outstanding Trust Units of the Trust. As a result of the issuance of a majority of Class B Trust Units in connection with Pengrowth s acquisition of Crispin in 2005, and the issuance of Class B Trust Units in accordance with the Distribution Reinvestment Program and other Pengrowth incentive plans, the ownership threshold of 49.75% for the Class A Trust Units was achieved prior to June 1, 2005 in accordance with the advance income tax ruling.

On November 26, 2004, the Trust received a customary form of comfort letter from the Department of Finance (Canada) (the November Finance Letter) stating that the Department of Finance will recommend to the Minister of Finance that an amendment be made to the Property Exception that would clarify the Trust s ability to rely upon the Property Exception and would effectively remove any significant risk regarding the status of the Trust as a mutual fund trust. This letter is subject to acceptance of the recommendations therein by the Minister of Finance and Parliament which, based on discussions with the Department of Finance and legal advisors, management of the Corporation believes is reasonable to assume will occur.

On December 6, 2004, the Minister of Finance tabled a Notice of Ways and Means Motion in the House of Commons to implement measures proposed in the March 23, 2004 Federal Budget. However, the changes to the mutual fund trust provisions proposed in the March 23, 2004 Federal Budget to remove the Property Exception were not included. The Minister of Finance indicated that further discussions would be pursued with the private sector concerning the appropriate tax treatment of non-residents investing in resource property through mutual funds. As a result, uncertainty remained as to whether or not the Property Exception would be available to royalty trusts such as the Trust indefinitely.

On September 8, 2005 the Federal government issued a consultation paper entitled Tax and Other Issues Related to Publicly Listed Flow-Through Entities for the purpose of launching consultations with stakeholders on tax issues related to business income trusts and other flow-through entities. On September 19, 2005 the Minister of Finance announced that the Minister of National Revenue had been requested to postpone providing any advance income tax rulings respecting flow-through entity structures, including trusts, effective immediately. On November 23, 2005 the Minister of Finance announced that in response to concerns regarding income trusts and other flow-through entities there would be a reduction in personal income taxes on dividends to help level the playing field between corporations and income trusts, and announced an end to the consultation process. As a result, the Minister of National Revenue resumed providing advance tax rulings on flow-through entity structures.

As a result of the uncertainty, Pengrowth considered it prudent to maintain the Class A and Class B Trust Unit structure in compliance with the advance income tax ruling. The Trust has also relied on the provisions of the November Finance Letter.

Pengrowth held discussions with the Tax Legislation Division of the Department of Finance and on March 23, 2006 the Trust received a letter from the Department of Finance (Canada) confirming that it remains the intention of the Department of Finance to recommend to the Minister of Finance the changes to the *Tax Act* contained in the November Finance Letter. Counsel to Pengrowth has advised that as a result of a number of factors, including receipt by the Corporation of certain confirmations from the Canada Revenue Agency and the Department of Finance including the November Finance Letter and the March 23, 2006 letter, it is no longer necessary to monitor or regulate the level of ownership of Trust Units by persons who are not Canadian residents in order to preserve Pengrowth s status as a mutual fund trust.

During February and March 2006 the spread between the trading values of the Class A and Class B Trust Units declined to the lowest level since shortly after implementing the structure in July 2004. In light of these developments the Board of Directors considered it appropriate to examine whether the Class A and Class B Trust Unit structure continues to be in the best interests of the Trust and its Unitholders and the extent to which the structure may be hindering the execution by Pengrowth of its business plan.

On March 27, 2006 Pengrowth announced the formation of a special committee of the Board of Directors to make recommendations to the Board of Directors. The special committee consists of A. Terence Poole (Chairman), Thomas A. Cumming, Kirby L. Hedrick and Michael S. Parrett, all of whom are independent directors. The mandate of the special committee includes examining the impact of Pengrowth s Class A and Class B Trust Unit structure and examining alternatives to that structure including the removal of the restriction from the Class B Trust Units, the merger of the Class A Trust Units and the Class B Trust Units into a single class of Trust Units or any other alternatives the committee considers appropriate, together with the impact of any course of action on Pengrowth and both the Class A Unitholders and Class B Unitholders and the methods of implementation thereof.

Prior to forming the special committee the Board of Directors sought advice from Canadian and U.S. counsel and preliminary advice from potential financial advisors. The special committee will retain its own financial advisors and has been granted the authority to retain such other advisors as it considers appropriate.

There can be no assurance regarding any changes the special committee will recommend to the Board of Directors, the likelihood of the implementation of any such recommendations, the consequences of such implementation, including the potential effect on the market price or value of the Class A Trust Units or Class B Trust Units, which effect may be significantly different as between the Class A Trust Units and Class B Trust Units or the terms or timing thereof.

At the annual and special meeting of holders of Trust Units on April 26, 2005, the Unitholders authorized the Board of Directors on behalf of the Corporation as administrator of the Trust, to make amendments to the Trust Indenture at the discretion of the Board of Directors to change the rights pertaining to Class A Trust Units and Class B Trust Units. The power and authority granted to the Board of Directors as described above provides broad and extraordinary powers to the Board of Directors. The Board of Directors may exercise this discretion or may seek ratification of authority or additional authority from the Unitholders. Any exercise of discretion by the Board of Directors will be done in a manner it believes is in the best interests of the Trust and the Trust Unitholders.

Key Features of the Trust Units

The key features of the Class A Trust Units and the Class B Trust Units as they are currently constituted are as follows:

Class A Trust Units

- are not subject to any residency restriction;
- are subject to a restriction on the number to be issued such that the total number of issued and outstanding Class A Trust Units will not exceed 99% of the number of issued and outstanding Class B Trust Units (after an initial implementation period) (the Ownership Threshold);

- may be converted by a holder at any time into Class B Trust Units provided that the holder is a resident of Canada and provides a suitable residency declaration;
- trade on both the TSX and NYSE; and
- have identical rights to voting, distributions and assets of Pengrowth Trust on a wind-up to the Class B Trust Units.

Class B Trust Units

- may not be owned or controlled, directly or indirectly, otherwise than by security only, by non-residents of Canada;
- trade only on the TSX;
- may be converted by a holder into Class A Trust Units, provided that the Ownership Threshold will not be exceeded (see page 11 General Development of Pengrowth Trust - Recent Acquisitions, Financings and Developments Conversion of Class B Trust Units into Class A Trust Units); and
- have identical rights to voting, distributions and assets of Pengrowth Trust on a wind-up to the Class A Trust Units.

A resident of Canada for the purposes of the *Tax Act* generally includes a person who is resident, for taxation purposes, in Canada based on such factors as physical location, personal and economic ties, citizenship, place of domicile and place of incorporation or establishment. In general, a person will be a resident of Canada if the person is required to file tax returns in Canada and is subject to Canadian tax on worldwide income as a Canadian resident. If you are uncertain as to your residency for the purposes of the *Tax Act* and any applicable income tax treaty or convention, you should consult with your tax advisors.

Ownership of Class B Trust Units Restricted

The following procedures have been adopted to monitor and constrain the ownership of Class B Trust Units by non-residents of Canada:

- The Canadian Depository for Securities Limited (CDS) has been advised that it is prohibited from holding Class B Trust Units on behalf of non-residents. Pengrowth Corporation will require participants in the book-based system to provide a participant declaration on a periodic basis to ensure that no non-resident of Canada owns any Class B Trust Units;
- Depository Trust Company (DTC) is not be permitted to hold Class B Trust Units;
- a residency declaration is required for any proposed registered transfer of Class B Trust Units; and
- a residency declaration is required for any proposed conversion of Class A Trust Units into Class B Trust Units.

These rules and procedures may be amended from time to time by Pengrowth Trust and Computershare.

Violations of Ownership Provisions

If it appears from the securities registers, or if the Board of Directors of the Corporation determines that, the number of issued and outstanding Class A Trust Units exceeds the Ownership Threshold, from and after June 1, 2005, or such other enforcement date that may be set in accordance with Unitholder approval, the Trust may make a public announcement of the contravention and shall refuse to accept subscriptions for Class A Trust Units or accept conversions of Class B Trust Units into Class A Trust Units. In addition, if the Board of Directors of the Corporation determines that it would not be unfairly prejudicial to, and would not unfairly disregard the interests of, persons beneficially owning or controlling Class A Trust Units, the Trust shall send a notice to the registered holders of Class A Trust Units chosen on the basis of inverse order of registration requiring such holders to dispose of their

Class A Trust Units and pending such disposition may suspend all rights of ownership attached to such Trust Units (including the right to receive distributions). Any such disposition notice will specify in reasonable detail: (i) the nature of the contravention of the Ownership Threshold; (ii) the number of Class A Trust Units that are in excess of the Ownership Threshold; (iii) a date, which shall not be less than 60 days after the date of the notice, by which the Class A Trust Units are to be (A) sold or otherwise disposed of to a person who is not a non-resident of Canada and who concurrently agrees to convert such units into Class B Trust Units or (B) if the holder is not a non-resident of Canada, converted into Class B Trust Units; and (iv) state that unless the holder complies, the Trust may sell or redeem the excess Class A Trust Units held by such holder. If a holder of Class A Trust Units fails to comply with such notice, the Trust may elect to sell, on behalf of the registered holder, the excess Class A Trust Units on its principal stock exchange and pay to the holder the net proceeds of the sale after deduction of any commission, tax or other costs of sale. In addition, if the holder fails to comply with the notice, and the Trust determines that a sale of the excess Class A Trust Units would be impracticable or have a material adverse effect on the market value of the Class A Trust Units, the Trust shall elect to repurchase or redeem the excess Class A Trust Units, without providing further notice. The repurchase or redemption price to be paid for such excess Class A Trust Units will be the 10 day average closing price of the Class B Trust Units on their principal stock exchange.

If it appears from the securities registers, or if the Board of Directors of the Corporation determines that, a person that is a non-resident of Canada holds or beneficially owns any Class B Trust Units, the Trust shall send a notice to the registered holder(s) of the Class B Trust Units requiring such holder(s) to dispose of the Class B Trust Units and pending such disposition may suspend all rights of ownership attached to such Trust Units (including the right to receive distributions). Any such disposition notice would specify in reasonable detail: (i) the number of Trust Units held by such holder; (ii) a date, which shall not be less than 60 days after the date of the notice, by which the Class B Trust Units are to be sold or otherwise disposed of to a person who is not a non-resident of Canada (and does not hold on behalf of any person who is a non-resident of Canada), or by which the holder must provide a declaration that they are not a non-resident of Canada; and (iii) state that unless the holder complies, the Trust may sell or redeem the Class B Trust Units held by such holder. If the holder of Class B Trust Units fails to comply with such notice, the Trust may elect to sell, on behalf of the registered holder, the Class B Trust Units on its principal stock exchange and pay to the holder the net proceeds of the sale after deduction of any commission, tax or other costs of sale. In addition, if the holder fails to comply with the notice, and the Trust determines that a sale of the excess Class B Trust Units would be impracticable or have a material adverse effect on the market value of the Class B Trust Units, the Trust may elect to repurchase or redeem the excess Class B Trust Units, without providing further notice. The repurchase or redemption price to be paid for such Class B Trust Units will be the 10 day average closing price of the Class B Trust Units on their principal stock exchange.

Exclusionary Offers

If an offer is made to purchase Class A Trust Units that must, by reason of securities legislation or stock exchange requirements, be made to all or substantially all of the owners of Class A Trust Units and such offer is not made concurrently with an offer to purchase Class B Trust Units that is identical to the offer to purchase Class A Trust Units in terms of price per Trust Unit and in all other material respects, then each outstanding Class B Trust Unit shall be convertible into one Class A Trust Unit at the option of the holder thereof from the day the offer is made until the expiry date of the offer. In these circumstances, the Ownership Threshold would temporarily cease to apply in respect of the Class A Trust Units. An election of the holder of Class B Trust Units to exercise this conversion right shall also be deemed to constitute the irrevocable election by the holder to deposit such units pursuant to the offer and to exercise a right of the holder to convert such units back into Class B Trust Units if such units are not taken up and paid for under the offer.

If an offer is made to purchase Class B Trust Units that must, by reason of securities legislation or stock exchange requirements, be made to all or substantially all of the owners of Class B Trust Units and such offer is not made concurrently with an offer to purchase Class A Trust Units that is identical to the offer to purchase Class B Trust Units in terms of price per Trust Unit and in all other material respects, then each outstanding Class A Trust Unit shall be convertible into one Class B Trust Unit at the option of the holder thereof. In these circumstances, the restriction on the ownership of Class B Trust Units by non-residents of Canada would temporarily cease to apply in respect of such

Class B Trust Units. An election of the holder of Class A Trust Units to exercise this conversion right shall also be deemed to constitute the irrevocable election by the holder to deposit such units pursuant to the offer and to exercise a right of the holder to convert such units back into Class A Trust Units if such units are not taken up and paid for under the offer.

In order to ensure that compliance with the coat-tail requirements of the TSX would not jeopardize Pengrowth s mutual fund trust status, the trust indenture restricts the operation of these provisions to ensure that the Ownership Threshold cannot be violated by providing that in respect of exclusionary offers made for only one class of Trust Units:

- holders of Class A Trust Units do not have the right to convert Class A Trust Units to Class B Trust Units where an exclusionary offer is made for the Class B Trust Units if the offeror is a non-resident of Canada (this would not be a valid offer because a non-resident is not permitted to hold Class B Trust Units);

- where Class B Trust Units are converted to Class A Trust Units upon an exclusionary offer being made for the Class A Trust Units, those units will be immediately converted back to Class B Trust Units upon being taken up and paid for to preserve the relative number of Class A Trust Units and Class B Trust Units outstanding both before and after the bid (even if the offeror is a non-resident of Canada and Pengrowth will have all of the remedies described above against such offeror);

- if a non-resident acquires 10 percent or more of the outstanding Class A Trust Units (including Class A Trust Units issued on the conversion of Class B Trust Units) the non-resident shall not be entitled to vote or receive distributions in respect to all of such units. These sanctions provide a strong disincentive for a non-resident to make an exclusionary offer for Class A Trust Units;

- if Class A Trust Units or Class B Trust Units are tendered to an exclusionary offer for the Class B Trust Units or the Class A Trust Units, respectively, the deemed conversion of such units is delayed until the take-up of the units pursuant to the offer and not before; and

- if an exclusionary offer is withdrawn or expires, or Trust Units that are tendered to an exclusionary offer are withdrawn, no conversion will occur.

THE ROYALTY INDENTURE

Royalty Units

Royalty units are issued under the terms of the royalty indenture. A maximum of 500,000,000 royalty units can be created and issued pursuant to the royalty indenture. The royalty units represent fractional undivided interests in the royalty, consisting of a 99 percent share of royalty income .

The royalty indenture, among other things, provides for the grant of the royalty, the issue of royalty units, the imposition on and acceptance by the Corporation of certain obligations and business restrictions, the calling of meetings of Unitholders, the conduct of business thereat, notice provisions, the appointment and removal of the trustee, and the establishment and use of the reserve as discussed below.

The royalty indenture may be amended or varied only by extraordinary resolution of the Unitholders and the holders of royalty units, or by the Corporation and Computershare, as trustee, for certain specifically defined purposes so long as, in the opinion of Computershare, the Unitholders and the holders of royalty units are not prejudiced as a result.

The holders of royalty units other than the trustee are currently entitled to vote at shareholder meetings of the Corporation on the basis of one vote for each royalty unit held.

At the special meeting of royalty Unitholders held on April 22, 2004, amendments to the royalty indenture were approved by the Unitholders to facilitate the issuance of exchangeable shares by the Corporation. See 50 Exchangeable Shares .

The Royalty

The royalty consists of a 99 percent share of royalty income . Under the terms of the royalty indenture, the Corporation is entitled to retain a one percent share of royalty income and all miscellaneous income (the Residual Interest) to the extent this amount exceeds the aggregate of debt service charges, general and administrative expenses, and management fees. In 2005 and 2004, this Residual Interest, as computed, did not result in any income being retained by the Corporation. The royalty indenture provides that royalty income means the aggregate of any special distributions and gross revenue less, without duplication, the aggregate of the following amounts:

a. operating costs;

b. general and administrative costs;

c. management fees and debt service charges;

d. taxes or other charges payable by the Corporation; and

e. any amounts paid into the reserve .

Gross revenues essentially consist of cash proceeds from the sale of petroleum substances produced from the properties of the Corporation and all other money and things of value received by or incurring to the Corporation by virtue of its legal and beneficial ownership of the properties, but not including processing or transportation revenues or proceeds from the sale of properties. Special distributions essentially consist of proceeds from the sale of properties that the Corporation is unable to reinvest in suitable replacement properties.

The reserve is established by the Corporation with miscellaneous revenues (such as processing and transportation revenues) and allowable portions of gross revenue, and must be used to fund the payment of operating costs, future abandonments, environmental and reclamation costs, general and administrative costs, management fees and debt service charges. Any amounts remaining in the reserve when there are no longer any properties that are subject to the royalty, and all of the above obligations have been satisfied, are to be paid to the Trust and to the holders of common shares and exchangeable shares of the Corporation in proportion to their respective interests.

The Corporation is required to pay to the holders of royalty units, on each cash distribution date, 99 percent of royalty income received by the Corporation from the properties for the period ending on the last day of the second month immediately preceding that cash distribution date, less the percentage of distributable cash that is retained by the Corporation to fund capital obligations. See page 50 Distributions . The holders of royalty units, including the Trust, will reimburse the Corporation for 99 percent of the non-deductible Crown royalties and other non-deductible Crown charges payable by the Corporation in respect of production from, or ownership of, the properties. The Corporation will at all times be entitled to set off its right to be so reimbursed against its obligation to pay the royalty.

To date, the Corporation has not incurred income taxes but is subject to the federal large corporation tax and the Saskatchewan resource surcharge. Any taxes payable by the Corporation will reduce royalty income, and thus the distributions received by Unitholders and holders of royalty units.

The Trustee

Computershare is the trustee for holders of royalty units under the royalty indenture and will remain the trustee thereunder unless it resigns or is removed by Unitholders. Computershare or its successor may resign on 60 days prior notice to the Unitholders, and may be removed by extraordinary resolution of the Unitholders. Computershare s successor must be approved in the same manner.

Computershare, in accordance with its power to delegate under the trust indenture, has appointed the Corporation as the administrator of the Trust to assume those functions of the trustee which are largely discretionary pursuant to the royalty indenture, subject to the powers and duties of the Manager pursuant to the management agreement.

EXCHANGEABLE SHARES

At the shareholders meeting and royalty Unitholders meeting conducted on April 22, 2004, amendments to the Unanimous Shareholder Agreement were approved to facilitate the issuance of exchangeable shares. The amendments approved will give the Board of Directors greater flexibility to issue a series of exchangeable shares of the Corporation which could meet the Corporation s objectives of creating a security that is economically similar to Trust Units, marketable in Canada, the United States and internationally, with favourable income tax consequences in the offered jurisdictions and that can be issued by the Trust without exceeding the residency restrictions under the mutual fund trust requirements of the *Tax Act*. Among other things, exchangeable shares may provide a valuable alternative source of equity to the Corporation to finance ongoing capital commitments of the Corporation, new acquisitions and for other general corporate purposes. The exchangeable shares will be securities of the Corporation that have rights upon a liquidation, wind-up or dissolution of the Corporation (a Liquidation Event) that are economically similar to the rights of Trust Unitholders under the trust indenture and royalty indenture, except in relation to assets other than royalty units that may be held by the Trust and the impact of general claims against the Corporation. As a result of the amendments approved, exchangeable shares will have the same rights as the rights of the holders of common shares of the Corporation to vote, to dividends or to share splits in lieu of dividends and to the assets of the Corporation upon the occurrence of a Liquidation Event.

In addition to the foregoing objective, the exchangeable shares may be eligible for investment by certain classes of investors for whom there are limitations with respect to holding Trust Units. The exchangeable shares may also facilitate business combinations and acquisitions and may be issued to the Manager should there be a wind-up or termination of the Management Agreement.

The creation of exchangeable shares was originally approved by Unitholders at the annual and special meetings held on June 17, 2003. It was contemplated at that time if a Liquidation Event were to occur, that holders of exchangeable shares would exercise their exchange right for Trust Units and would participate along with Trust Unitholders in accordance with provisions prescribed by the royalty indenture and the Trust Indenture. However, a series of exchangeable shares may, from time to time, be issued that would limit the right of exchange to holders of exchangeable shares who are resident in Canada or the right of exchange may otherwise be prescribed in terms of Class B Trust Units and the conditions of ownership thereof.

In order not to disenfranchise any holders of exchangeable shares and to create clear rights with respect to the assets of the Corporation subject to claims against the Corporation, Unitholder approval was obtained to make appropriate amendments to the royalty indenture to create insolvency rights with respect to the assets of the Corporation which are economically similar to the rights of Trust Unitholders under the Trust Indenture and the royalty indenture. Although economically similar, these rights are distinct from the rights of holders of Trust Units in that the holders of exchangeable shares shall only have a claim against the assets of the Corporation if a Liquidation Event shall occur and shall have no claim against the cash or other assets of the Trust. The exchangeable shares, shall in the same manner as the common shares, be subject to claims made against the Corporation generally.

Upon a Liquidation Event, an amount will be withheld from the assets or monies available for distribution to royalty Unitholders under the royalty indenture to be paid to holders of the exchangeable shares and common shares representing the proportion of the economic interests in the Corporation represented by the exchangeable shares and in the common shares compared with the beneficial economic interest in the Corporation held by the Trust Unitholders (through the royalty units held by the Trust).

DISTRIBUTIONS

Pengrowth makes monthly payments to our Unitholders on the 15th of each month or the first business day following the 15th. The record date for any distribution is ten business days prior to the distribution date. In accordance with stock exchange rules, an ex-distribution date occurs two trading days prior to the record date to permit time for settlement of trades of securities and distributions must be declared a minimum of seven trading days before the record date.

Actual distributions paid or declared per Trust Unit for each quarter for the preceding five fiscal years were as follows:

ACTUAL DISTRIBUTIONS PAID OR DECLARED PER TRUST UNIT
(Canadian $)

	2005	2004	2003	2002	2001
First Quarter	0.69	0.63	0.75	0.41	1.14
Second Quarter	0.69	0.64	0.67	0.54	0.83
Third Quarter	0.69	0.67	0.63	0.52	0.63
Fourth Quarter	0.75	0.69	0.63	0.60	0.41

All amounts distributed to Unitholders from the inception of the Trust to December 31, 2005 have been treated as a return of capital, except that in 1996, 1999, 2000, 2001, 2002, 2003, 2004 and 2005 respectively, the Trust had taxable income per Trust Unit of $0.2044, $0.6742, $1.9831, $1.7951, $0.4252, $1.4692, $1.4328 and $2.2241 respectively, which was allocated to Unitholders representing 12.2 percent, 30.4 percent, 55.8 percent, 51.4 percent, 22.0 percent, 55.2 percent, 55.3 percent and 80.0 percent of total cash distributions for those years. For Canadian residents, amounts which are treated as a return of capital generally are not required to be included in a Unitholder s income but such amounts will reduce the adjusted cost base to the Unitholder of the Trust Units.

At the special meeting of the royalty Unitholders of the Corporation held on April 23, 2002, the royalty Unitholders approved the amendment of the royalty indenture to permit the board of directors of the Corporation to establish a holdback, within the Corporation, of up to 20 percent of its gross revenue if the board of directors of the Corporation determines that it would be advisable to do so in accordance with prudent business practices to provide for the payment of future capital expenditures or for the payment of royalty income in any future period. Subsequent to this royalty Unitholder action, the board of directors of the Corporation authorized the establishment of a holdback to fund future capital obligations and future payments of royalty income to the Trust while providing a measure of stability to the monthly distribution amount.

INDUSTRY CONDITIONS

Government Regulation

The oil and natural gas industry is subject to extensive controls and regulation imposed by various levels of government. Although we do not expect that these controls and regulation will affect the operations of Pengrowth in a manner materially different than they would affect other oil and gas companies of similar size, the controls and regulations should be considered carefully by investors in the oil and gas industry. All current legislation is a matter of public record and Pengrowth is unable to predict what additional legislation or amendments may be enacted.

Pricing and Marketing Oil

In Canada, producers of oil negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Such price depends, in part, on oil type and quality, prices of competing fuels, distance to market, the value of refined products, the supply/demand balance, other contractual terms and the world price of oil. Oil exports may be made pursuant to export contracts with terms not exceeding one year, in the case of light crude, and not exceeding two years, in the case of heavy crude, provided that an order approving any such export has been obtained from the National Energy Board. 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 licence from the National Energy Board and the issuance of such licence requires approval of the Governor in Council.

Pricing and Marketing Natural Gas

In Canada, the price of natural gas sold in intraprovincial, interprovincial and international trade is determined by negotiation between buyers and sellers. Such price depends, in part, on natural gas quality, prices of competing fuels, distance to market, access to downstream transportation, length of contract term, weather conditions, the supply/demand balance and other contractual terms. Natural gas exported from Canada is subject to regulation by the National Energy Board and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain criteria prescribed by the National Energy Board and the Government of Canada. Natural gas exports for a term of less than two years or for a term of 2 to 20 years (in quantities of not more than 30,000 m3/day), must be made pursuant to an order of the National Energy Board. 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 licence from the National Energy Board and the issue of such a licence requires the approval of the Governor in Council.

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

Pricing and Marketing Natural Gas Liquids

In Canada, the price of natural gas liquids (NGLs) sold in intraprovincial, interprovincial and international trade is determined by negotiation between buyers and sellers. Such price depends, in part, on the quality of the NGLs, prices of competing chemical stock, distance to market, access to downstream transportation, length of contract term, the supply/demand balance and other contractual terms. NGLs exported from Canada are subject to regulation by the National Energy Board and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain criteria prescribed by the National Energy Board and the Government of Canada. NGL may be exported for a term of no more than one year in respect to propane and butane, and no more than two years in respect to ethane, all exports requiring an order of the National Energy Board.

The North American Free Trade Agreement

On January 1, 1994, the North American Free Trade Agreement (NAFTA) among the Governments of Canada, United States and Mexico became effective. NAFTA carries forward most of the material energy terms contained in the Canada-United States Free Trade Agreement. In the context of energy resources, Canada continues to remain free to determine whether exports to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resource 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 and, except as permitted in enforcement of countervailing and anti-dumping orders and undertakings, minimum or maximum import price requirements.

NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes. NAFTA 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

The federal and provincial governments in Canada have legislation and regulations which govern land tenure, royalties, production rates, environmental protection and other matters. The royalty regime is a significant factor in the profitability of oil and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the freehold mineral owner and the lessee, although production from such lands is also subject to certain provincial taxes. Royalties on production from Crown lands are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production, and the rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location and field discovery date.

The Government of Alberta s royalty structure includes incentives for exploring and developing oil and natural gas reserves. The incentives include a modification of the royalty formula structure through the implementation of a third tier royalty. For oil produced from wells drilled after September, 1992, oil royalty reserved to the Crown has a base rate of 10% and a rate cap of 25%. The oil royalty reserved to the Crown on older oil wells has a base rate of 10% and a rate cap of 30% 35%, depending on the age of the well. 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 on a prescribed or corporate average reference price.

In Alberta, certain producers of oil or natural gas are also entitled to a credit against the royalties payable to the Alberta Crown by virtue of the Alberta royalty tax credit program. The Alberta royalty tax credit program is based on a price-sensitive formula, and the percentage of royalties rebated varies between 75%, when the calculated blended price for oil and natural gas is below $100 per cubic meter, and 25% when such price is above $210 per cubic meter. The Alberta royalty tax credit program 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 companies claiming maximum entitlement to Alberta royalty tax credit will generally not be eligible for the Alberta royalty tax credit. The Alberta royalty tax credit program rate is established quarterly based on the average par price , as determined by the Alberta Resource Development Department for the previous quarterly period.

In British Columbia, the amount of Crown royalties payable 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. Natural gas produced in association with oil has a minimum royalty of 8% while the royalty in respect of other natural gas may not be less than 9% 15%, depending on the age of the well.

On May 30, 2003, the Minister of Energy and Mines for British Columbia announced an Oil and Gas Development Strategy for the Heartlands. The strategy, which was updated in November 2003, is a comprehensive program to address road infrastructure, targeted royalties, and regulatory reduction and service-sector opportunities. Some of the financial incentives include: (i) royalty credits of up to $30 million annually towards road infrastructure in support of resource development (industry must make an equal contribution); (ii) royalty credits for deep gas exploration, re-entry and horizontal drilling; and (iii) royalty credits for unconventional and new basins.

The new fiscal regime for the Saskatchewan oil and gas industry, effective October 1, 2002, provides an incentive to encourage exploration and development through a revised royalty/tax structure for oil and natural gas wells with a finished drilling date on or after October 1, 2002 or incremental oil production due to a new or expanded waterflood project with a commencement date on or after October 1, 2002. This fourth tier Crown royalty rate, applicable to both oil and natural gas, is price sensitive and ranges from 5% of the first $50/1000m3 of the price of natural gas and of the first $100/m3 of the price of oil, to 30% of the portion of the price above those amounts. A fourth tier freehold tax structure, calculated by subtracting a production tax factor of 12.5 percentage points from the corresponding Crown royalty rates, has also been created which is applicable to conventional oil, incremental oil from new or expanded waterfloods and natural gas. The fourth tier royalty/tax structure is also applicable in respect of associated natural gas that is gathered for use or sale which is produced either from oil wells with a finished drilling date prior to October 1, 2002, where the individual oil well has a gas-oil production ratio in any month of more than 3,500 m3 of natural gas per 1 m3 of oil. In addition, volume-based royalty/tax reduction incentives have been changed such that a maximum royalty of 2.5% now applies to various volumes of both oil and natural gas, depending on the depth and nature of the well (up to 16,000 m3 of oil in the case of deep exploratory wells and 25,000 m3 of natural gas produced from exploratory wells). The royalty/tax category with respect to re-entry and short sectional horizontal oil wells has been eliminated such that all horizontal oil wells with a finished drilling date on or after October 1, 2002 will receive fourth tier royalty/tax rates and incentive volumes. Further changes include the reduction of the corporation capital tax surcharge rate from 3.6% to 2.0% and the expansion of the deep oil well definition to include oil wells producing from a zone deeper than 1,700 meters provided that the zone is within a geological system deposited during the Mississippian Period or earlier or from a zone that was deposited before the Bakken zone regardless of depth.

The Government of Nova Scotia has established a generic royalty regime in respect of oil and gas produced from offshore Nova Scotia. Such regime contemplates a multi-tier royalty in which the royalty rate fluctuates when certain threshold levels of rates of return on capital have been reached. Notwithstanding the generic royalty regime,

royalties in respect of offshore Nova Scotia oil and gas production may be determined contractually between the participant and the Government of Nova Scotia.

Oil and natural gas royalty holidays and reductions for specific wells reduce the amount of Crown royalties paid by Pengrowth to the provincial governments. The Alberta royalty tax credit program provides a rebate on Alberta Crown royalties paid in respect of eligible producing properties. These incentives result in increased net income and funds from the operations of Pengrowth.

Environmental Regulation

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

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 nation-wide emissions of carbon dioxide, methane, nitrous oxide and other greenhouse gases . In April 2005, the Government of Canada put forwarded an updated Climate Change Plan for Canada which suggests future legislation will set greenhouse gases emission reduction requirements for various industrial activities, including oil and gas exploration and production. It is anticipated that greenhouse gas emitters will be allowed to meet their emission reduction targets in a number of ways, including perhaps most notably, the trading of credits with other emitters that have exceeded their reduction targets. Pengrowth s exploration and production facilities and other operations emit greenhouse gases, making it possible that Pengrowth will be subject to such future federal legislation. Additionally, provincial emission reduction requirements, such as those contained in Alberta s Climate Change and Emissions Managements Act (partially in force), may also require the reduction of emissions or emissions intensity from the Company s operations and facilities. The direct and indirect costs of these regulations may adversely affect the business of Pengrowth. Pengrowth may however earn carbon credits offsetting liabilities which may be created under future legislation due to Pengrowth s participation in the carbon dioxide miscible recovery scheme at Weyburn and other potential tertiary recovery projects in the future.

Pengrowth is committed to meeting its responsibilities to protect the environment wherever it operates and anticipates making increased expenditures of both a capital and expense nature as a result of increasingly stringent laws relating to the protection of the environment. The Corporation will be taking such steps as required to ensure compliance with the *Alberta Environmental Protection and Enhancement Act,* the *Environmental Assessment Act (British Columbia)* and similar legislation or requirements in other jurisdictions in which it operates. Pengrowth believes that it is in material compliance with applicable environmental laws and regulations. Pengrowth also believes that it is reasonably likely that the trend in environmental legislation and regulation will continue toward stricter standards.

MARKET FOR SECURITIES

Pengrowth s Class A Trust Units are listed on both the TSX and the NYSE under the symbols PGF.A and PGH , respectively, and our Class B Trust Units are listed on the TSX under the symbol PGF.B .

Class A Trust Units

	Toronto Stock Exchange Share Price Range				New York Stock Exchange Share Price Range			
	High	**Low**	**Close**	**Volume**	**High**	**Low**	**Close**	**Volume**
	(Canadian $ per trust unit)			(thousands)	(U.S. $ per trust unit)			(thousands)
2005								
January	26.51	23.18	25.76	484	21.44	19.10	20.75	6,259
February	28.29	25.75	26.75	962	22.94	20.75	21.56	7,330
March	26.80	22.15	24.03	603	21.56	18.11	20.00	11,032
April	26.01	23.95	25.30	684	20.95	19.20	20.17	6,511
May	26.39	24.23	25.89	422	20.79	19.05	20.61	4,307
June	27.90	25.75	27.20	692	22.74	20.62	22.25	5,335
July	28.98	26.84	28.55	634	23.45	22.00	23.40	4,265
August	29.39	26.30	28.39	593	24.20	21.55	23.93	6,025
September	30.10	27.38	29.50	820	25.75	23.05	25.42	4,212
October	29.80	23.64	25.58	687	25.56	20.00	21.75	8,554
November	27.85	24.61	26.65	427	23.74	20.75	22.84	5,448
December	28.35	26.51	27.41	211	24.35	22.95	23.53	3,807

Class B Trust Units

	Toronto Stock Exchange Share Price Range			
	High	**Low**	**Close**	**Volume**
	(Canadian $ per trust unit)			(thousands)
2005				
January	19.25	18.24	18.95	7,574
February	19.90	18.79	18.88	10,415
March	18.80	16.10	17.05	11,230
April	18.08	16.37	17.24	6,682
May	17.98	16.80	17.50	6,121
June	19.01	17.41	18.40	6,566
July	18.50	18.95	18.50	7,747
August	19.47	18.25	19.45	7,523
September	21.26	19.28	20.58	7,467
October	20.83	17.27	18.50	5,651
November	21.75	18.34	21.35	6,032
Decem ber	23.38	20.87	22.65	8,064

DIRECTORS AND OFFICERS

The Trust does not have any directors or officers. The following is a summary of information relating to the directors and officers respectively of Pengrowth Management, Manager of the Corporation and the Trust, and of the Corporation, the administrator of the Trust.

Directors and Officers of Pengrowth Management Limited

The name, municipality of residence, position held and principal occupation of each director and officer of Pengrowth Management are set out below:

Name and Municipality of Residence	Position with Pengrowth Management	Principal Occupation
James S. Kinnear Calgary, Alberta	President and Director (since 1982)	President, Pengrowth Management Limited
Gordon M. Anderson Calgary, Alberta	Vice President, Financial Services (since 2001) Vice President, Treasurer (1998-2001) Treasurer (1995-1998)	Vice President, Financial Services Pengrowth Management Limited
Charles V. Selby Calgary, Alberta	Corporate Secretary (since 1993)	Lawyer, Selby Professional Corporation Lawyer and Corporate Financial Advisor

Each of the foregoing directors and officers has had the same principal occupation for the previous five years except for Mr. Anderson who was Vice President, Treasurer (1998-2001).

Principal Holders of Shares of Pengrowth Management

James S. Kinnear, President and a director of Pengrowth Management and Chairman, President, Chief Executive Officer and a director of the Corporation, owns, directly or indirectly, all of the issued and outstanding voting securities of Pengrowth Management.

Directors and Officers of the Corporation
The name, municipality of residence, position held and principal occupation of each director and officer of the Corporation are set out below:

Name and Municipality of Residence	Position with Pengrowth Corporation	Principal Occupation	Trust Units Controlled or Beneficially Owned(1)(2)
James S. Kinnear(7) Calgary, Alberta	President, Chairman, Director and Chief Executive Office (since 1988)	President, Pengrowth Management Limited	4,051,039
Stanley H. Wong(4)(8) Calgary, Alberta	Director (since 1988)	President, Carbine Resources Ltd. a private oil and gas producing and engineering consulting company	46,576
John B. Zaozirny(5)(6) Calgary, Alberta	Director (since 1988)	Counsel, McCarthy Tétrault, Barristers and Solicitors	47,362
Thomas A. Cumming(3)(5)(6) Calgary, Alberta	Director (since 2000)	Business Consultant	6,678
Michael S. Parrett(3)(5)(6) Aurora, Ontario	Director (since 2004)	Business Consultant	4,000
Kirby L. Hedrick(3)(4) Pinedale, Wyoming	Director (since 2005)	Business Consultant	Nil
A. Terence Poole(3)(5) Calgary, Alberta	Director (since 2005)	Executive Vice President, Corporate Strategy and Development, Nova Chemicals Corporation	10,000
Gordon M. Anderson Calgary, Alberta	Vice President (since 2001) Vice President, Treasurer (1997-2001) Treasurer (1995-1997) Chief Financial Officer (1991-1998)	Vice President, Financial Services, Pengrowth Management Limited	47,245
Charles V. Selby Calgary, Alberta	Vice President and Corporate Secretary (since 2005) Corporate Secretary (since 1993)	Lawyer, Selby Professional Corporation Lawyer and Corporate Financial Advisor	127,970
Chris Webster Calgary, Alberta	Chief Financial Officer (since 2005) Treasurer (2000 2005)	Chief Financial Officer Pengrowth Corporation	19,348
Larry B. Strong Bragg Creek, Alberta	Vice President, Geosciences (since 2005)	Vice President, Geosciences Pengrowth Corporation	16,357

William G. Christensen Calgary, Alberta	Vice President, Strategic Planning and Reservoir Exploitation (since 2005)	Vice President, Strategic Planning and Reservoir Exploitation Pengrowth Corporation	5,589
James E.A. Causgrove Calgary, Alberta	Vice President, Production and Operations (since 2005)	Vice President, Production and Operations Pengrowth Corporation	11,330
Douglas C. Bowles Calgary, Alberta	Vice President and Controller (since March 1, 2006) Controller (since 2005)	Vice President and Controller Pengrowth Corporation	3,834
Peter Cheung Calgary, Alberta	Treasurer (since 2005)	Treasurer Pengrowth Corporation	4,653

Notes:

1. Does not include Class B Trust Units issuable upon the exercise of outstanding Trust Unit options, Trust Unit rights or deferred entitlement units.

2. As at March 7, 2006.

3. Member of Audit Committee.

4. Member of Reserves Committee.

5. Member of Corporate Governance Committee.

6. Member of the Compensation Committee.

7. In addition, Mr. Kinnear exercises control over 13,152 royalty units which are held by Pengrowth Management Limited.

8. In addition, Mr. Wong exercises control over 3,288 royalty units held by Carbine Resources Ltd.

As at March 24, 2006, the foregoing directors and officers, as a group, beneficially, owned, directly or indirectly, 4,400,822 Class B Trust Units and 1,159 Class A Trust Units or approximately 2.74 percent of the issued and outstanding Trust Units and held options and rights to acquire a further 636,169 Class B Trust Units. Assuming exercise of all options and rights, the foregoing directors and officers, as a group, would beneficially own, directly and indirectly, 5,038,150 Trust Units or approximately 3.14 percent of the then issued and outstanding Trust Units. The information as to shares beneficially owned, not being within the knowledge of the Corporation, has been furnished by the respective individuals.

The term of each director expires at the next annual meeting of Unitholders. The next annual meeting of Unitholders is currently scheduled to be held on May 30, 2006.

Each of the foregoing directors and officers has had the same principal occupation for the previous five years except for Mr. Cumming who was President of the Alberta Stock Exchange from 1988 to 1999; Michael S. Parrett who was Vice-President and Chief Financial Officer of Rio Algom Limited from 1991 to 2000, Vice-President, Strategic Development and Joint Ventures of Rio from 1999 to 2000 and President of Rio from 2000 to 2001; Chris Webster who was Vice President, Treasurer from September 30, 2004 to 2005, Treasurer from 2001 to September 30, 2004, Manager, Operations Accounting from 2000 to 2001 and Team Leader, Marketing Accounting and Treasury, Union Pacific Resources Inc. from 1996 to 2000; Larry Strong who was Vice President Geosciences & Officer of Petrofund Corp. from 2004 to 2005, Senior Vice President of MarkWest Resources Canada from 2001 to 2003 and Director Geosciences of Waterous & Co. from 1998 to 2001; Bill Christensen who was Vice President Planning of Northrock Resources from 2000 to 2005; Jim Causgrove who was Manager, New Growth Opportunities of Chevron Texaco Canada from 2003 to 2005 and Senior Vice President and Chief Operating Officer of Central Alberta Midstream from 2000 to 2003; Doug Bowles who was Financial Reporting Manager from 2003 to 2005, Senior Planning Analyst from 2001 to 2003 and Senior Financial Analyst from 2000 to 2001 of ExxonMobil Canada; and Peter Cheung who was an Investment Banker with RBC Capital Markets from 2000 to 2005.

Corporate Cease Trade Orders or Bankruptcies

No current or proposed director, officer or controlling securityholder of Pengrowth or Pengrowth Management is as at the date of this annual information form or has been, within the past 10 years before the date hereof, a director or officer of any other issuer that, while that person was acting in that capacity:

(i) was the subject of a cease trade or similar order or an order that denied the issuer access to any exemption under securities legislation for a period of more than 30 consecutive days; or

(ii) was subject to an event that resulted, after the person ceased to be a director or executive officer, in the issuer being the subject of a cease trade or similar order or an order that denied the issuer access to any exemption under securities legislation for a period of more than 30 consecutive days; or

(iii) within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets.

Personal Bankruptcies

No current or proposed director, officer or controlling securityholder of Pengrowth or Pengrowth Management has, within the past 10 years before the date hereof, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or became subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver manager or trustee appointed to hold such person s assets.

Penalties or Sanctions

No current or proposed director, officer or controlling securityholder of Pengrowth or Pengrowth Management has:

(i) been subject to any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority, other than: (a) penalties for late filing of insider reports; and (b) Mr. Selby, the Corporate Secretary of the Corporation, and other directors of AltaCanada Energy Corp. entered into a settlement agreement in 1998 with the Alberta Securities Commission in regard to the application of rules governing junior capital pool companies to drilling expenses assumed by the directors on behalf of the Company; or

(ii) been subject to any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

AUDIT COMMITTEE

The Audit Committee is appointed annually by the Board of Directors. The responsibilities and duties of the Audit Committee are set forth in the Audit Committee Charter attached hereto as Appendix C. The following table sets forth the name of each of the current members of the Audit Committee, whether such member is independent, as defined in Multilateral Instrument 52-110 Audit Committees, whether such member is financially literate, in that they are able to read and understand a set of financial statements that represents the breadth and level of complexity of accounting issues that can reasonably be expected to arise in Pengrowth s financial statements, and the relevant education and experience of such member:

Name	**Independent**	**Financially Literate**	**Relevant Education and Experience**
Thomas A. Cumming	Yes	Yes	Mr. Cumming was President and Chief Executive Officer of the Alberta Stock Exchange from 1988 to 1999. His career also includes 25 years with a major Canadian bank both nationally and internationally. He is currently Chairman of Alberta s Electricity Balancing Pool, and serves as a Director of the Canadian Investor Protection Fund, the Alberta Capital Market Foundation and Western Lakota Energy Services Inc. Mr. Cumming is a professional engineer and holds a Bachelor of Applied Science degree in Engineering and Business.
Michael S. Parrett	Yes	Yes	Mr. Parrett is currently an independent consultant providing advisory service to various public companies in Canada and the United States. Mr. Parrett is a member of the Board of Fording Inc. and is serving as a Trustee for Fording Canadian Coal Trust as well as the Chairman of Gabriel Resources Limited. He formerly was President of Rio Algom Limited and prior to that Chief Financial Officer of Rio Algom and Falconbridge Limited. Mr. Parrett is a chartered accountant and holds a Bachelor of Arts in Economics from York University.
A. Terence Poole	Yes	Yes	Mr. Poole is currently the Executive Vice President, Corporate Strategy and Development of Nova Chemicals Corporation. Prior to assuming his present position in 2000, he held various senior management positions with Nova and other companies. Mr. Poole brings extensive senior financial management, accounting, capital and debt market experience to Pengrowth. Mr. Poole received a Bachelor of Commerce degree from Dalhousie University and holds a Chartered Accountant designation.

Kirby L. Hedrick	Yes	Yes	Mr. Hedrick has extensive engineering and senior management experience in the United States and internationally, retiring in 2000 as Executive Vice President, Upstream of Phillips Petroleum. He currently serves on the board of Noble Energy Inc. Mr. Hedrick received a Bachelor of Science and Mechanical Engineering degree from the University of Evansville, Indiana in 1975. He completed the Stanford Executive Program in 1997 and the Stanford Corporate Governance Program in 2003.

Principal Accountant Fees and Services

The following table provides information about the aggregate fees billed to Pengrowth for professional services rendered by KPMG LLP during fiscal 2005 and 2004:

Category	2005 $M	2004 $M
Audit Fees	305	624
Audit Related Fees		
Tax Fees	104	102
All Other Fees	6	6
Total	415	732

Audit Fees. Audit fees consist of fees for the audit of Pengrowth s annual financial statements and services that are normally provided in connection with statutory and regulatory filings or engagements.

Audit-Related Fees. Audit-related fees normally include due diligence reviews in connection with acquisitions, research of accounting and audit-related issues and the completion of audits required by contracts to which Pengrowth is a party.

Tax Fees. During 2005 and 2004 the services provided in this category included assistance and advice in relation to the preparation of income tax returns for Pengrowth and its subsidiaries, tax advice and planning and commodity tax consultation.

All Other Fees. During 2005 and 2004 the services provided in this category included consultation regarding the *U.S. Sarbanes Oxley Act* and internal controls.

Pre-approval Policies and Procedures

Pengrowth has adopted the following policies and procedures with respect to the pre-approval of audit and permitted non-audit services to be provided by KPMG LLP: The audit committee approves a schedule which summarizes the services to be provided that the audit committee believes to be typical, recurring or otherwise likely to be provided by KPMG LLP. The schedule generally covers the period between the adoption of the schedule and the end of the year, but at the option of the audit committee, may cover a shorter or longer period. The list of services is sufficiently detailed as to the particular services to be provided to ensure that (i) the audit committee knows precisely what services it is being asked to pre-approve and (ii) it is not necessary for any member of Pengrowth s management to make a judgment as to whether a proposed service fits within the pre-approved services. Services that arise that were not contemplated in the schedule must be pre-approved by the audit committee chairman or a delegate of the audit committee. The full audit committee is informed of the services at its next meeting.

Pengrowth has not approved any non-audit services on the basis of the *de minimis* exemptions. All non-audit services are pre-approved by the Audit Committee in accordance with the pre-approval policy referenced herein.

RISK FACTORS

If any of the following risks occur, our production, revenues and financial condition could be materially harmed, with a resulting decrease in distributions on, and the market price of, our Trust Units. As a result, the trading price of our Trust Units could decline, and you could lose all or part of your investment. ***Additional risks are described under the heading Business Risks in the Management s Discussion Analysis appearing on page 76 of the Trust s Annual Report 2005.***

Our distributions are sensitive to the volatility of crude oil and natural gas prices.
The monthly distributions we pay to our Unitholders depend, in part, on the prices we receive for our oil and natural gas production. Oil and natural gas prices can fluctuate widely on a month-to-month basis in response to a variety of factors that are beyond our control. These factors include, among others:

- global energy policy, including the ability of OPEC to set and maintain production levels, for oil;
- political conditions in the Middle East;
- worldwide economic conditions;
- weather conditions including weather-related disruptions to the North American natural gas supply;
- the supply and price of foreign oil and natural gas;
- the level of consumer demand;
- the price and availability of alternative fuels;
- the proximity to, and capacity of, transportation facilities;
- the effect of worldwide energy conservation measures; and
- government regulation.

Declines in oil or natural gas prices could have an adverse effect on our operations, financial condition and proved reserves and ultimately on our ability to pay distributions to our Unitholders.

Our distributions are affected by production and development costs and capital expenditures.
Production and development costs incurred with respect to properties, including power costs and the costs of injection fluids associated with tertiary recovery operations, reduce the royalty income that the Trust receives and, consequently, the amounts we can distribute to our Unitholders.

The timing and amount of capital expenditures will directly affect the amount of income available for distribution to our Unitholders. Distributions may be reduced, or even eliminated, at times when significant capital or other expenditures are made. To the extent that external sources of capital, including the issuance of additional Trust Units, become limited or unavailable, the Corporation s ability to make the necessary capital investments to maintain or expand oil and gas reserves and to invest in assets, as the case may be, will be impaired. To the extent that the Corporation is required to use cash flow to finance capital expenditures or property acquisitions, the cash we receive from the Corporation on the royalty units will be reduced, resulting in reductions to the amount of cash we are able to distribute to our Unitholders.

Our actual results will vary from our reserve estimates, and those variations could be material.
The value of the Trust Units will depend upon, among other things, the Corporation s reserves. In making strategic decisions, we generally rely upon reports prepared by our independent reserve engineers. Estimating reserves is inherently uncertain. Ultimately, actual production, revenues and expenditures for the underlying properties will vary from estimates and those variations could be material. Changes in the prices of, and markets for, oil and natural gas from those anticipated at the time of making such assessments will affect the return on, and value of, our Trust Units. The reserve and cash flow information contained in this Annual Information Form or contained in the documents incorporated by reference represent estimates only. Petroleum engineers consider many factors and make assumptions in estimating reserves. Those factors and assumptions include:

- historical production from the area compared with production rates from similar producing areas;
- the assumed effect of government regulation;

assumptions about future commodity prices, exchange rates, production and development costs, capital expenditures, abandonment costs, environmental liabilities, and applicable royalty regimes;

initial production rates;

production decline rates;

ultimate recovery of reserves;

marketability of production; and

other government levies that may be imposed over the producing life of reserves.

If these factors and assumptions prove to be inaccurate, our actual results may vary materially from our reserve estimates. Many of these factors are subject to change and are beyond our control. In particular, changes in the prices of, and markets for, oil and natural gas from those anticipated at the time of making such assessments will affect the return on, and value of, our Trust Units. In addition, all such assessments involve a measure of geological and engineering uncertainty that could result in lower production and reserves than anticipated. A significant portion of our reserves are classified as undeveloped and are subject to greater uncertainty than reserves classified as developed .

In accordance with normal industry practices, we engage independent petroleum engineers to conduct a detailed engineering evaluation of our oil and gas properties for the purpose of estimating our reserves as part of our year end reporting process. As a result of that evaluation, we may increase or decrease the estimates of our reserves. We do not consider an increase or decrease in the estimates of our reserves in the range of one to five percent to be material or inconsistent with normal industry practice. Any significant reduction to the estimates of our reserves resulting from any such evaluation could have a material adverse effect on the value of our Trust Units.

Our reserves will be depleted over time and our level of distributable cash and the value of our Trust Units could be reduced if reserves are not replaced.

Our future oil and natural gas reserves and production, and therefore the cash flows of the Trust, will depend upon our success in acquiring additional reserves. If we fail to add reserves by acquiring or developing them, our reserves and production will decline over time as they are produced. When reserves from our properties can no longer be economically produced and marketed, our Trust Units will have no value unless additional reserves have been acquired or developed. If we are not able to raise capital on favourable terms, we may not be able to add to or maintain our reserves. If we use our cash flow to acquire or develop reserves, we will reduce our distributable cash.

There is strong competition in all aspects of the oil and gas industry including reserve acquisitions. We will actively compete for reserve acquisitions and skilled industry personnel with a substantial number of other oil and gas companies and energy trusts. However, many of our competitors have greater resources than we do and we cannot assure you that we will be successful in acquiring additional reserves on terms that meet our objectives.

Our operation of oil and natural gas wells could subject us to environmental claims and liability.

The oil and natural gas industry is subject to extensive environmental regulation, which imposes restrictions and prohibitions on releases or emissions of various substances produced in association with certain oil and gas industry operations. In addition, Canadian legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. A breach of this or other legislation may result in fines or the issuance of a clean-up order. Ongoing environmental obligations will be funded out of our cash flow and could therefore reduce distributable cash payable to our Unitholders.

We may be unable to successfully compete with other companies in our industry.

There is strong competition in all aspects of the oil and gas industry. Pengrowth will actively compete for capital, skilled personnel, undeveloped lands, reserve acquisitions, access to drilling rigs, service rigs and other equipment, access to processing facilities and pipeline and refining capacity and in all other aspects of its operations with a substantial number of other organizations, many of which may have greater technical and financial resources than Pengrowth. Some of those organizations not only explore for, develop and produce oil and natural gas but also carry

on refining operations and market oil and other products on a world-wide basis and, as such, have greater and more diverse resources on which to draw.

Incorrect assessments of value at the time of acquisitions could adversely affect the value of our Trust Units and our distributions.

Acquisitions of oil and gas properties or companies will be based in large part on engineering and economic assessments made by independent engineers. These assessments include a series of assumptions regarding such factors as recoverability and marketability of oil and gas, future prices of oil and gas and operating costs, future capital expenditures and royalties and other government levies which will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond our control. All such assessments involve a measure of geologic and engineering uncertainty which could result in lower production and reserves than anticipated.

Our level of debt could have a material adverse effect on our ability to pay distributions to our Unitholders.

The Corporation has issued U.S. $200 million in term debt due in two tranches, the first tranche of U.S. $150 million is due in April 2010 and the second tranche of U.S. $50 million is due in April 2013. Pengrowth has issued £50 million in term debt due December 2015. Pengrowth also has a $370 million revolving credit facility syndicated among eight financial institutions in place until June 16, 2006. The $370 million facility has a 364 day revolving period and should it not be renewed on June 16, 2006, it will be repayable over a three year period. Pengrowth also has a $35 million demand operating line of credit. We draw upon these credit facilities from time to time to make acquisitions of oil and natural gas properties and to fund capital investments in our properties. We pay interest at fluctuating rates with respect to a portion of our outstanding debt under our existing credit facilities. Variations in exchange rates, interest rates and scheduled principal repayments could result in significant changes in the amount Pengrowth is required to apply to service its debt. Certain covenants in the agreements with our lenders may also limit the amount of the royalty paid by the Corporation to the Trust and the distributions paid by us to our Unitholders. We cannot assure you that the amount of our credit facility will be adequate for our future financial obligations or that we will be able to obtain additional funds. If we become unable to pay our debt service charges or otherwise cause an event of default to occur, our lenders may foreclose on or sell the properties. The net proceeds of any such sale will be allocated firstly, to the repayment of our lenders and other creditors and only the remainder, if any, would be payable to the Trust by the Corporation in respect of the royalty.

Loss of our key management and other personnel could impact our business.

Our Unitholders are entirely dependent on the management of the Manager and the Corporation with respect to the acquisition of oil and gas properties and assets, the development and acquisition of additional reserves, the management and administration of all matters relating to properties and the administration of the Trust. The loss of the services of key individuals who currently comprise the management team of the Manager and the Corporation could have a detrimental effect on the Trust. In addition, increased activity within the oil and gas sector can increase the cost of goods and services and make it more difficult to have and retain qualified professional staff.

Trust distributions are affected by marketability of production.

The marketability of our production depends in part upon the availability, proximity and capacity of gas gathering systems, pipelines and processing facilities. United States federal and state and Canadian federal and provincial regulation of oil and gas production and transportation, general economic conditions, and changes in supply and demand could adversely affect our ability to produce and market oil and natural gas. If market factors dramatically change, the financial impact on us could be substantial. The availability of markets is beyond our control.

The operation of a significant portion of our properties is largely dependent on the ability of third party operators, and harm to their business could cause delays and additional expenses in our receiving revenues.

The continuing production from a property, and to some extent the marketing of production, is dependent upon the ability of the operators of our properties. Approximately 45 percent of our properties are operated by third parties, based on daily production. If, in situations where we are not the operator, the operator fails to perform these functions properly or becomes insolvent, then revenues may be reduced. Revenues from production generally flow through the operator and, where we are not the operator, there is a risk of delay and additional expense in receiving such revenues.

The operation of the wells located on properties not operated by us are generally governed by operating agreements which typically require the operator to conduct operations in a good and workmanlike manner. Operating agreements generally provide, however, that the operator will have no liability to the other non-operating Working Interest owners for losses sustained or liabilities incurred, except such as may result from gross negligence or wilful misconduct. In addition, third-party operators are generally not fiduciaries with respect to the Corporation, the Trust or the Unitholders. The Corporation, as owner of Working Interests in properties not operated by it, will generally have a cause of action for damages arising from a breach of the operator s duty. Although not established by definitive legal precedent, it is unlikely that the Trust or our Unitholders would be entitled to bring suit against third-party operators to enforce the terms of the operating agreements. Therefore, our Unitholders will be dependent upon the Corporation, as owner of the Working Interest, to enforce such rights.

Our distributions could be adversely affected by unforeseen title defects.

Although title reviews are conducted prior to any purchase of resource assets, such reviews cannot guarantee that an unforeseen defect in the chain of title will not arise to defeat our title to certain assets. Such defects could reduce the amounts distributable to our Unitholders, and could result in a reduction of capital.

Fluctuations in foreign currency exchange rates could adversely affect our business.

World oil prices are quoted in United States dollars and the price received by Canadian producers is therefore affected by the Canadian/United States dollar exchange rate which fluctuates over time. A material increase in the value of the Canadian dollar may negatively impact our net production revenue and cash flow. To the extent that we have engaged, or in the future engage, in risk management activities related to commodity prices and foreign exchange rates, through entry into oil or natural gas price hedges and forward foreign exchange contracts or otherwise, we may be subject to unfavourable price changes and credit risks associated with the counterparties with which we contract.

A decline in the value of the Canadian dollar relative to the United States dollar provides a competitive advantage to United States companies in acquiring Canadian oil and gas properties and may make it more difficult for us to replace reserves through acquisitions.

Being a limited purpose trust makes the Trust largely dependent upon the operations and assets of the Corporation.

The Trust is a limited purpose trust which is dependent upon the operations and assets of the Corporation. The Corporation s income will be received from the production of crude oil and natural gas from its properties and will be susceptible to the risks and uncertainties associated with the oil and natural gas industry generally. Since the primary focus is to pursue growth opportunities through the development of existing reserves and the acquisition of new properties, the Corporation s involvement in the exploration for oil and natural gas is minimal. As a result, if the oil and natural gas reserves associated with the Corporation s resource properties are not supplemented through additional development or the acquisition of oil and natural gas properties, the ability of the Corporation to continue to generate cash flow for distribution to Unitholders may be adversely affected.

Management may have conflicts of interest.

The Manager provides advisory, management and administrative needs of the Trust and the Corporation in consideration for a management fee which is currently based in part on net production revenue of the Corporation. This arrangement may create an incentive for the Manager to maximize the net production revenue of the Corporation, rather than maximizing its distributable cash, which is the primary basis for calculating distributions available to Unitholders.

The Manager may manage and administer such additional acquired properties, as well as enter into other types of energy related management and advisory activities and may not devote full time and attention to the business of the Corporation and therefore act in contradiction to or competition with the interests of our Unitholders.

General and administrative expenses which the Manager incurs in relation to the business of the Corporation and the Trust are required to be paid by the Corporation. These expenses are not subject to a limit other than as may be provided under a periodic review by the Board of Directors and, as a result, there may not be an incentive for the Manager to minimize these expenses.

We may incur material costs to comply with, or as a result of, health, safety and environmental laws and regulations.

Compliance with environmental laws and regulations could materially increase our costs. We may incur substantial capital and operating costs to comply with increasingly complex laws and regulations covering the protection of the environment and human health and safety. In particular, we may be required to incur significant costs to comply with the 1997 Kyoto Protocol to the United Nations Framework Convention on Climate Change, known as the Kyoto Protocol that is intended to reduce emissions of pollutants into the air.

Lower oil and gas prices increase the risk of write-downs of our oil and gas property investments.

Under Canadian accounting rules, the net capitalized cost of oil and gas properties may not exceed a ceiling limit which is based, in part, upon estimated future net cash flows from reserves. If the net capitalized costs exceed this limit, we must charge the amount of the excess against earnings. As oil and gas prices decline, our net capitalized cost may approach and, in certain circumstances, exceed this cost ceiling, resulting in a charge against earnings. Under United States accounting rules, the cost ceiling is generally lower than under Canadian rules because the future net cash flows used in the United States ceiling test are discounted to a present value. Accordingly, we would have more risk of a ceiling test write-down in a declining price environment if we reported under United States generally accepted accounting principles. While these write-downs would not affect cash flow, the charge to earnings could be viewed unfavourably in the market or could limit our ability to borrow funds or comply with covenants contained in our current or future credit agreements or other debt instruments.

Changes in Canadian legislation could adversely affect the value of our Trust Units.

The value of the Trust Units is largely related to our income tax treatment. We cannot assure you that income tax laws and government incentive programs relating to the oil and natural gas industry generally, the status of royalty trusts having our structure, the Alberta royalty tax credit and the resource allowance will remain favourable and not change in a manner that adversely affects your investment.

If the Trust ceases to qualify as a mutual fund trust it would adversely affect the value of our Trust Units.

It is intended that the Trust will at all times qualify as a mutual fund trust for the purposes of the *Tax Act*. Notwithstanding the steps taken or to be taken by Pengrowth, no assurance can be given that the status of the Trust as a mutual fund trust will not be challenged by a relevant taxation authority. If the Trust s status as a mutual fund trust is determined to have been lost, certain negative tax consequences will have resulted for the Trust and its Unitholders. These negative tax consequences include the following:

- The Trust Units would cease to be a qualified investment for trusts governed by RRSPs, RRIFs, RESPs and DPSPs, as defined in the *Tax Act*. Where, at the end of a month, a RRSP, RRIF, RESP or DPSP holds Trust Units that ceased to be a qualified investment, the RRSP, RRIF, RESP or DPSP, as the case may be, must, in respect of that month, pay a tax under Part XI.1 of the *Tax Act* equal to 1 percent of the fair market value of the Trust Units at the time such Trust Units were acquired by the RRSP, RRIF, RESP or DPSP. In addition, trusts governed by a RRSP or a RRIF which hold Trust Units that are not qualified investments will be subject to tax on the income attributable to the Trust Units while they are non-qualified investments, including the full capital gains, if any, realized on the disposition of such Trust Units. Where a trust governed by a RRSP or a RRIF acquires Trust Units that are not qualified investments, the value of the investment will be included in the income of the annuitant for the year of the acquisition. Trusts governed by RESPs which hold Trust Units that are not qualified investments can have their registration revoked by the Canada Revenue Agency.

The Trust would be required to pay a tax under Part XII.2 of the *Tax Act*. The payment of Part XII.2 tax by the Trust may have adverse income tax consequences for certain Unit holders, including non-resident persons and residents of Canada who are exempt from Part I tax.

The Trust Units would be foreign property for RRSPs, RRIFs DPSPs and other persons subject to tax under Part XI of the *Tax Act*.

The Trust would not be entitled to use the capital gains refund mechanism otherwise available for mutual fund trusts.

The Trust Units would constitute taxable Canadian property for the purposes of the *Tax Act*, potentially subjecting non-residents of Canada to tax pursuant to the *Tax Act* on the disposition (or deemed disposition) of such Trust Units.

Changes to the terms of the Class A Trust Units or to the Class B Trust Units could adversely affect the market value of either class of Trust Units.

The special committee of the Board of Directors formed on March 27, 2006 will make recommendations to the Board of Directors in accordance with its mandate to determine whether the Class A and Class B Trust Unit structure continues to be in the best interest of the Trust and its Unitholders and whether the structure may be hindering the execution by Pengrowth of its business plan. The Board of Directors has requested that the special committee examine alternatives to the Class A and Class B Trust Unit structure. Alternatives to be investigated include the removal of the ownership restrictions from the Class B Trust Units, the merger of the Class A Trust Units and the Class B Trust Units into a single class of Trust Units or any other alternatives the committee considers appropriate.

There can be no assurance regarding any changes the special committee will recommend to the Board of Directors, the likelihood of implementation of any such recommendations, the consequences of such implementation, including the potential effect on the market price or value of the Class A Trust Units or Class B Trust Units, which effect may be significantly different as between the Class A Trust Units and Class B Trust Units or the terms or timing thereof.

The ability of investors resident in the United States to enforce civil remedies may be affected for a number of reasons.

The Trust is an Alberta trust and the Manager and the Corporation are both Alberta corporations. All of these entities have their principal places of business in Canada. All of the directors and officers of the Manager and the Corporation are residents of Canada and all or a substantial portion of the assets of such persons and of the Trust are located outside of the United States. Consequently, it may be difficult for United States investors to effect service of process within the United States upon the Trust or such persons or to realize in the United States upon judgments of courts of the United States predicated upon civil remedies under the *Securities Act of 1933* (United States), as amended.

Investors should not assume that Canadian courts:

a. will enforce judgments of United States courts obtained in actions against the Trust or such persons predicated upon the civil liability provisions of the United States federal securities laws or the securities or blue sky laws of any state within the United States; or

b. will enforce, in original actions, liabilities against the Trust or such persons predicated upon the United States federal securities laws or any such state securities or blue sky laws.

Our Trust Units are not equivalent to shares.

Trust Units should not be viewed by investors as shares in the Corporation. Trust Units are also dissimilar to conventional debt instruments in that there is no principal amount owing to our Unitholders. Trust Units represent a fractional interest in the Trust. Unitholders will not have the statutory rights normally associated with ownership of shares of a corporation including, for example, the right to bring oppression or derivative actions. The Trust s assets are royalty units and common shares of the Corporation and certain facilities interests, and may also include certain other investments permitted under the trust indenture. The price per Trust Unit is a function of anticipated distributable cash, the oil and natural gas properties acquired by the Corporation and the ability to effect long-term growth in the value of the Corporation. The market price of the Trust Units will be sensitive to a variety of market conditions including, but not limited to, interest rates and the ability of the Corporation to acquire suitable oil and natural gas properties. Changes in market conditions may adversely affect the trading price of our Trust Units.

Trust Units will have no value when reserves from the properties can no longer be economically produced or marketed and, as a result, cash distributions do not represent a yield in the traditional sense as they represent both return of capital and return on investment. Unitholders will have to obtain the return of capital invested out of cash flow derived from their investments in the Trust Units during the period when reserves can be economically recovered. Accordingly, we give no assurances that the distributions you receive over the life of your investment will meet or exceed your initial capital investment.

You may experience substantial future dilution given that the success of the Trust is dependent upon raising capital.

One of our objectives is to continually add to our reserves through acquisitions and through development. Our success is, in part, dependent on our ability to raise capital from time to time. Unitholders may also suffer dilution in connection with future issuance of Trust Units.

Canadian and United States practices differ in reporting reserves and production.

We report our production and reserve quantities in accordance with Canadian practices and specifically in accordance with NI 51-101. These practices are different from the practices used to report production and to estimate reserves in reports and other materials filed with the United States Securities and Exchange Commission by companies in the United States.

We incorporate additional information with respect to production and reserves which is either not generally included or prohibited under rules of the United States Securities and Exchange Commission and practices in the United States. We follow the Canadian practice of reporting gross production and reserve volumes; however, we also follow the United States practice of separately reporting these volumes on a net basis (after the deduction of royalties and similar payments). We also follow the Canadian practice of using forecast prices and costs when we estimate our reserves; however, we separately estimate our reserves using prices and costs held constant at the effective date of the reserve report in accordance with the Canadian reserve reporting requirements. These requirements are similar to the constant pricing reserve methodology utilized in the United States.

We include in this Annual Information Form estimates of proved and proved plus probable reserves. The United States Securities and Exchange Commission generally prohibits the inclusion of estimates of probable reserves in filings made with it. This prohibition does not apply to the Trust because it is a Canadian foreign private issuer.

You may be required to pay taxes even if you do not receive any cash distributions.

You may be required to pay federal income taxes and, in some cases, state, provincial and local income taxes on your share of our taxable income even if you do not receive any cash distributions from us. You may not receive cash distributions from us equal to your share of our taxable income or even equal to the actual tax liability that results from your share of our taxable income.

Unitholders who are United States persons face income tax risks.

The United States federal income tax risks related to owning and disposing of our Trust Units, include the following:

Because the Trust Units will be publicly traded, the Trust will not be treated as a corporation for U.S. federal income tax purposes only if 90 percent or more of its gross income consists of qualifying income. Although the Trust expects to satisfy the 90 percent requirement at all times, if it fails to satisfy this requirement, it will be treated as a foreign corporation. If the Trust were treated as a corporation, it could be a passive foreign investment company or PFIC . Treatment of the Trust as a PFIC could result in a material reduction in the after-tax return to the Unit holders, likely causing a substantial reduction in the value of the Trust Units.

A successful U.S. Internal Revenue Service (IRS) contest of the federal income tax positions we take or have taken may adversely affect the market for our Trust Units. For example, the IRS could challenge our position that the royalty from the Corporation should be treated as a non-operating, non-Working Interest. We have not requested a ruling from the IRS with respect to this or any other matter affecting us other than relating to the timeliness of our election to be treated as a partnership. The IRS may adopt positions that differ from the conclusions of our counsel or from the positions we take or have taken. It may be necessary to resort to administrative or court proceedings to sustain our counsel s conclusions or those positions. A court may not concur with our counsel s conclusions or the positions we take or have taken. Any contest with the IRS may materially and adversely impact the U.S. federal income tax consequences to Unitholders and, therefore, the market for our Trust Units and the price at which they trade. In addition, the costs of any contest with the IRS, principally legal, accounting and related fees, will be borne by us and indirectly by the Unitholders.

Tax gain or loss on disposition of Trust Units could be different from expected. If you sell your Trust Units, you will recognize gain or loss equal to the difference between the amount realized and your tax basis in the Trust Units. Prior distributions in excess of the total net taxable income you were allocated, which decreased your tax basis in the Trust Units, will, in effect, become taxable income to you if the Trust Units are sold at a price greater than your tax basis in those Trust Units, even if the price you receive is less than your original cost. A substantial portion of the amount realized, whether or not representing gain, may be ordinary income to you. Should the IRS successfully contest some positions we take, you could recognize more gain on the sale of Trust Units than would be the case under those positions, without the benefit of decreased income in prior years. Also, if you sell Trust Units, you may incur a tax liability in excess of the amount of cash you receive from the sale.

We have registered with the IRS as a tax shelter. This may increase the risk of an IRS audit of us or a Unitholder. The tax laws require that some types of entities register as tax shelters in response to the perception that they claim tax benefits that may be unwarranted. As a result, we may be audited by the IRS and tax adjustments could be made. Any Unitholder owning less than a 1 percent profits interest in us has very limited rights to participate in the income tax audit process. Further, any adjustments in our tax returns will lead to adjustments in our Unitholders tax returns and may lead to audits of Unitholders tax returns and adjustments of items unrelated to us. You will bear the cost of any expense incurred in connection with an examination of your personal tax return.

We will treat each owner of Trust Units as having the same tax benefits without regard to the specific Trust Units purchased. The IRS may challenge this treatment, which could adversely affect the value of our Trust Units. Because we cannot match transferors and transferees of our Trust Units, we will adopt depletion, depreciation and amortization positions that do not conform with all aspects of final Treasury regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to you. It also could affect the timing of these tax benefits or the amount of gain from your sale of Trust Units and could have a negative impact on the value of our Trust Units or result in audit adjustments to your tax returns.

The Trust may not be an appropriate investment for certain types of entities. For example, there is a risk that some of the Trust s income could be unrelated business taxable income with respect to tax-exempt organizations.

Furthermore, we anticipate that substantially all of the Trust s gross income will not be qualifying income for purposes of the rules relating to regulated investment companies.

Pengrowth s distributions may be reduced during periods in which it makes capital expenditures using cash flow.

To the extent that Pengrowth uses cash flow to finance acquisitions, development costs and other significant capital expenditures, the cash available to the Trust for the payment of distributions will be reduced. To the extent that external sources of capital, including the issuance of additional Trust Units, becomes limited or unavailable, Pengrowth s ability to make the necessary capital investments to maintain or expand its oil and gas reserves and to invest in assets, as the case may be, will be impaired.

Pengrowth s operations are subject to changes in government regulations and obtaining required regulatory approvals.

The oil and gas industry in Canada operates under federal, provincial and municipal legislation and regulation governing such matters as land tenure, prices, royalties, production rates, environmental protection controls, the exportation of crude oil, natural gas and other products, as well as other matters. The industry is also subject to regulation by governments in such matters as the awarding or acquisition of exploration and production rights, oil sands or other interests, the imposition of specific drilling obligations, environmental protection controls, control over the development and abandonment of fields and mine sites (including restrictions on production) and possibly expropriation or cancellation of contract rights. See page 51 Industry Conditions .

Government regulations may be changed from time to time in response to economic or political conditions. The exercise of discretion by governmental authorities under existing regulations, the implementation of new regulations or the modification of existing regulations affecting the crude oil and natural gas industry could reduce demand for crude oil and natural gas or increase Pengrowth s costs, either of which would have a material adverse impact on Pengrowth.

We will become subject to additional rules and regulations of the SEC related to internal controls for our fiscal year ending December 31, 2006 which we expect will increase our legal and compliance costs.

We are subject to the public reporting requirements of the United States Securities Exchange Act of 1934 and, we will be required to comply with Section 404 of the Sarbanes-Oxley Act of 2002, which we refer to as Section 404, for our fiscal year ending December 31, 2006. Section 404 will require us, among other things, annually to review and report on, and our independent registered public accounting firm to attest to, our internal control over financial reporting. We expect that compliance with Section 404 will increase our legal and financial compliance costs. Any failure to develop or maintain effective controls, or difficulties encountered in their implementation or other effective improvement of our internal controls could harm our operating results or cause us to fail to meet our reporting obligations. Given the difficulties inherent in the design and operation of internal controls over financial reporting, we can provide no assurance as to our, or our independent registered public accounting firm s, conclusions about the effectiveness of our internal controls. Ineffective internal controls subject us to regulatory scrutiny and a loss of confidence in our reported financial information, which could have an adverse effect on our business and would likely have a negative effect on the trading price of our trust units.

If Pengrowth expands operations beyond oil and natural gas production in Canada, Pengrowth may face new challenges and risks. If Pengrowth is unsuccessful in managing these challenges and risks, its results of operations and financial condition could be adversely affected.

Pengrowth s operations and expertise are currently focused on conventional oil and gas production and development in the Western Canadian Sedimentary Basin, together with its participation in SOEP. In the future, Pengrowth may acquire oil and natural gas properties outside these geographic areas. Expansion of Pengrowth s activities into new areas may present challenges and risks that it has not faced in the past. If Pengrowth does not manage these challenges and risks successfully, its results of operations and financial condition could be adversely affected.

Delays in business operations could adversely affect the Trust s distributions to Unitholders.
In addition to the usual delays in payment by purchasers of oil and natural gas to the operators of Pengrowth s properties, and the delays of those operators in remitting payment to Pengrowth, payments between any of these parties may also be delayed by:

- restrictions imposed by lenders;
- accounting delays;
- delays in the sale or delivery of products;
- delays in the connection of wells to a gathering system;
- blowouts or other accidents;
- adjustments for prior periods;
- recovery by the operator of expenses incurred in the operation of the properties; or
- the establishment by the operator of reserves for these expenses.

Any of these delays could reduce the amount of cash available for distribution to Pengrowth s Unitholders in a given period and expose Pengrowth to additional third party credit risks.

Changes in market-based factors may adversely affect the trading price of the Trust Units.
The market price of our Trust Units is sensitive to a variety of market based factors including, but not limited to, interest rates, foreign exchange rates and the comparability of the Trust s Trust Units to other yield-oriented securities. Any changes in these market-based factors may adversely affect the trading price of the Trust Units.

The limited liability of the Trust s Unitholders is uncertain.
Notwithstanding the fact that Alberta (the Trust s governing jurisdiction) has adopted legislation purporting to limit Trust Unitholder liability, because of uncertainties in the law relating to investment trusts, there is a risk that a Unitholder could be held personally liable for obligations of the Trust in respect of contracts or undertakings which the Trust enters into and for certain liabilities arising otherwise than out of contracts including claims in tort, claims for taxes and possibly certain other statutory liabilities. Pengrowth has structured itself and attempted to conduct its business in a manner which mitigates the Trust s liability exposure and where possible, limits its liability to Trust property. However, such protective actions may not completely avoid Unitholder liability. Notwithstanding Pengrowth s attempts to limit Unitholder liability, Unitholders may not be protected from liabilities of the Trust to the same extent that a shareholder is protected from the liabilities of a corporation. Further, although the Trust has agreed to indemnify and hold harmless each Unitholder from any costs, damages, liabilities, expenses, charges and losses suffered by a Unitholder resulting from or arising out of the Unitholder not having limited liability, Pengrowth cannot assure prospective investors that any assets would be available in these circumstances to reimburse Unitholders for any such liability. Legislation that purports to limit Trust Unitholder liability has been implemented in Alberta but there is no assurance that such legislation will eliminate all risk of Unitholder liability. Additionally, the legislation does not affect the liability of Unitholders with respect to any act, default, obligation or liability that arose prior to July 1, 2004.

The redemption right of Unitholders is limited.
Unitholders have a limited right to require the Trust to repurchase Trust Units, which is referred to as a redemption right. See page 42 Trust Units Redemption Right . It is anticipated that the redemption right will not be the primary mechanism for Unitholders to liquidate their investment. The Trust s ability to pay cash in connection with a redemption is subject to limitations. Any securities which may be distributed *in specie* to Unitholders in connection with a redemption may not be listed on any stock exchange and a market may not develop for such securities. In addition, there may be resale restrictions imposed by law upon the recipients of the securities pursuant to the

redemption right.

The industry in which Pengrowth operates exposes Pengrowth to potential liabilities that may not be covered by insurance.

Pengrowth s operations are subject to all of the risks normally associated with the operation and development of oil and natural gas properties, including the drilling of oil and natural gas wells and the production and transportation of oil and natural gas. These risks and hazards include encountering unexpected formations or pressures, blow-outs, craterings and fires, all of which could result in personal injury, loss of life or environmental and other damage to Pengrowth s property and the property of others. Pengrowth cannot fully protect against all of these risks, nor are all of these risks insurable. Pengrowth may become liable for damages arising from these events against which it cannot insure or against which it may elect not to insure because of high premium costs or other reasons. While Pengrowth has both safety and environmental policies in place to protect its operators and employees and to meet regulatory requirements in areas where they operate, any costs incurred to repair damages or pay liabilities would reduce the funds available for distribution to the Trust s Unitholders.

CONFLICTS OF INTEREST

There may be situations in which the interests of the Manager will conflict with those of our Unitholders. The Manager may acquire oil and natural gas properties on behalf of persons other than the Unitholders. The Manager may manage and administer such additional properties, as well as enter into other types of energy-related management and advisory activities. Accordingly, neither the Manager nor some member of its management may carry on their full-time activities on behalf of Unitholders and, when acting on behalf of others, may at times act in contradiction to or competition with the interests of Unitholders. In the event that the interests of the Manager are in conflict with those of our Unitholders, the Manager is obliged to make decisions acting in good faith, having regard to the best interests of Unitholders and in a manner that would not contravene its fiduciary obligations to Unitholders.

Although the Manager provides advisory and management services to the Corporation and the Trust, the Board of Directors supervises the management of the business and affairs of the Corporation and the Trust. As a practical matter, the Manager defers to the Board of Directors on all matters of material significance to the Unitholders. The Board of Directors makes significant operational decisions and all decisions relating to:

- the issuance of additional Trust Units;
- material acquisitions and dispositions of properties;
- material capital expenditures;
- borrowing; and
- the payment of distributable cash.

Properties may not be acquired from officers or directors of the Manager or persons not at arm s length with such persons at prices which are greater than fair market value and properties may not be sold to officers or directors of the Manager or persons not at arm s length with such persons at prices which are less than fair market value, in each case as established by an opinion of an independent financial advisor and approved by the independent members of the Board of Directors. There may be circumstances where certain transactions may also require the preparation of a formal valuation and the affirmative vote of Unitholders in accordance with the requirements of Ontario Securities Commission Rule 61-501 Insider Bids, Issuer Bids, Going Private Transactions and Related Party Transactions.

Circumstances may arise where members of the Board of Directors serve as directors or officers of corporations which are in competition to the interests of the Corporation and the Trust. No assurances can be given that opportunities identified by such board members will be provided to the Corporation and the Trust.

Mr. James S. Kinnear, President and a director of Pengrowth Management and Chairman, President, Chief Executive Officer and a director of the Corporation, is a shareholder (holding shares that represent less than one percent of the outstanding shares) of Rockwater Capital Corporation, of which Blackmont Capital Inc. is a subsidiary. Blackmont Capital Inc. (formerly First Associates Investments Inc.) has participated as a member of the syndicate of underwriters in connection with previous equity offerings by the Trust and received a portion of the

underwriters fee in connection therewith. First Associates Investments Inc. may participate as a member of the syndicate of underwriters in connection with future equity offerings by the Trust and would receive a portion of the underwriters fee in connection therewith.

Mr. John Zaozirny, the lead director of the Corporation, is the Vice-Chairman of Canaccord Capital Corporation. Canaccord Capital Corporation has participated as a member of the syndicate of underwriters in connection with previous equity offerings by the Trust and received a portion of the underwriters fee in connection therewith. Canaccord Capital Corporation may participate as a member of the syndicate of underwriters in connection with future equity offerings by the Trust and would receive a portion of the underwriters fee in connection therewith. In addition, Pengrowth retained Canaccord Capital Corporation to provide an opinion to the Board of Directors with respect to the fairness of the transactions between Pengrowth and Monterey and was paid a customary fee in connection therewith. In connection with that retention, Mr. Zaozirny declared his conflict and did not participate in the Board of Directors deliberations and determination to retain Canaccord Capital Corporation.

LEGAL PROCEEDINGS

There are no outstanding legal proceedings material to Pengrowth to which Pengrowth is a party or in respect of which any of its properties are subject, nor are there any such proceedings known to Pengrowth to be contemplated.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Other than as discussed herein, there are no material interests, direct or indirect, of directors, executive officers, senior officers, any direct or indirect Unitholder of Pengrowth who beneficially owns, or who exercises control over, more than 10 percent of the outstanding Trust Units or any known associate or affiliate of such persons, in any transaction within the three most recently completed financial years or during the current financial year that has materially affected or will materially affect Pengrowth.

Mr. James S. Kinnear, President and a director of Pengrowth Management and Chairman, President, Chief Executive Officer and a director of the Corporation, is a shareholder (holding shares that represent less than one percent of the outstanding shares) of Rockwater Capital Corporation, of which First Associates Investments Inc. is a subsidiary. First Associates Investments Inc. participated as a member of the syndicate of underwriters in connection with the December 30, 2004 equity offering by the Trust of 15,985,000 Class B Trust Units and received a portion of the underwriters fee.

Mr. John Zaozirny, the lead director of the Corporation, is the Vice-Chairman of Canaccord Capital Corporation. Canaccord Capital Corporation participated as a member of the syndicate of underwriters in connection with the March 23, 2004 and December 30, 2004 equity offerings by the Trust of 10,900,000 and 15,985,000 Trust Units, respectively, and received a portion of the underwriters fee from both offerings.

INTERESTS OF EXPERTS

As of the date hereof, the partners and associates, as a group of Bennett Jones LLP beneficially own, directly or indirectly, less than one percent of the outstanding Trust Units. As of the date hereof, the directors and officers of GLJ, as a group, beneficially own, directly or indirectly, less than one percent of the outstanding Trust Units.

AUDITORS, TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for the Class A Trust Units is Computershare Trust Company of Canada at its principal offices in the cities of Montreal, Toronto, Calgary and Vancouver in Canada and New York, New York and Denver, Colorado in the United States. The transfer agent and registrar for the Class B Trust Units is Computershare Trust Company of Canada at its principal offices in the cities of Montreal, Toronto, Calgary and Vancouver. The auditors of the Trust are KPMG LLP, Chartered Accountants in Calgary, Alberta.

MATERIAL CONTRACTS

The only material contracts entered into by the Corporation or the Trust during the most recently completed financial year, or before the most recently completed financial year that is still in effect, other than during the ordinary course of business, are as follows:

1. Trust Indenture*;*
2. Royalty Indenture;
3. Unanimous Shareholders Agreement; and
4. Management Agreement.

Copies of these contracts have been filed by the Trust on SEDAR and are available through the SEDAR website at www.sedar.com.

CODE OF ETHICS

Pengrowth has adopted a code of ethics, as that term is defined in Form 40-F under the *U.S. Securities Exchange Act of 1934* (the Code of Ethics) that applies to Pengrowth s management, including its Chief Executive Officer, Chief Financial Officer and principal accounting officer. The Code of Ethics is available for viewing on our website (www.pengrowth.com).

Pengrowth s Board of Directors adopted a new Code of Business Conduct and Ethics (Code) on November 3, 2005. The new Code does not detract from any of the requirements of the prior code and is more encompassing than the old code. All employees are being requested to accept the new Code in writing. As of March 24, 2006, 95 percent of the employees and Directors have signed the Code. We expect that all will sign within the next few weeks.

During the year ended December 31, 2005, Pengrowth has not granted any waivers (including implicit waivers) from the terms thereof in respect of its Chief Executive Officer, Chief Financial Officer and principal accounting officer.

OFF-BALANCE SHEET ARRANGEMENTS

Pengrowth has no off-balance sheet arrangements except for forward and future contracts disclosed in the notes to the financial statements and operating leases.

TABULAR DISCLOSURE OF CONTRACTUAL OBLIGATIONS

The disclosure regarding the contractual obligations of Pengrowth under the heading Commitments and Contractual Obligations in the Management s Discussion and Analysis appearing on page 72 of the Trust s Annual Report for the year ended December 31, 2005 is incorporated by reference herein.

DISCLOSURE PURSUANT TO THE REQUIREMENTS OF THE NEW YORK STOCK EXCHANGE

As a Canadian reporting issuer with securities listed on the TSX, Pengrowth has in place a system of corporate governance practices which complies with Canadian securities laws and the TSX corporate governance guidelines as well as the corporate governance rules of the NYSE applicable to foreign private issuers. In the context of its listing on the New York Stock Exchange, Pengrowth is classified as a foreign private issuer and therefore only certain of the NYSE rules are applicable to Pengrowth. However, Pengrowth benchmarks its policies and procedures against major north American entities, with a view to adopting the best practices when appropriate to its circumstances.

The Board of Directors of the Corporation has formerly adopted and published a Corporate Governance Policy which affirms Pengrowth s commitment to maintaining a high standard of corporate governance. This policy is published on Pengrowth s website at www.pengrowth.com. The Board of Directors of the Corporation has also adopted an Audit Committee Charter, Corporate Governance Committee Terms of Reference**,** Compensation Committee Terms of Reference, a Code of Business Conduct, a Corporate Disclosure Policy, an Insider Trading Policy and a Whistle Blower Policy each of which is published on Pengrowth s website. The Audit Committee Charter is also attached hereto as Appendix C.

The following is a summary of significant ways in which Pengrowth s corporate governance practices differ from those required to be followed by domestic United States issuers under the NYSE Listed Company Manual:

The NYSE Listed Company Manual requires that each member of the audit committee be financially literate and that at least one member of the audit committee have accounting or related financial management expertise. Pengrowth s Audit Committee Charter requires that all members of the Audit Committee be financially literate; however, it does not require that any member have accounting or related financial management experience. However, as a matter of practice, Pengrowth s Audit Committee includes a financial expert and thereby satisfies the NYSE requirement.

The NYSE Listed Company Manual requires the audit committee charter to address the duties and responsibilities of the committee which must include that the audit committee must discuss the listed company s earnings press releases, as well as financial information and earnings guidance provided to analysts and rating agencies. Pengrowth s audit committee charter does not require that the audit committee discuss this type of information before being released to the public or provided to analysts or rating agencies; however, Pengrowth has a written Corporate Disclosure Policy and has established a Disclosure Policy Committee consisting of the CEO, CFO, Manager of Investor Relations and Corporate Secretary. Pursuant to the Corporate Disclosure Policy, the Disclosure Policy Committee reviews, and makes determinations in respect of, all new releases issued by Pengrowth, and the release of information to analysts and investors.

The NYSE Listed Company Manual requires the written charter of the compensation committee to state that the committee has responsibility to review and approve corporate goals and objectives relevant to CEO compensation, evaluate the CEO s performance in light of those goals and objectives and either as a committee or together with the other independent directors (as directed by the board) determine and approve the CEO s compensation level based on this evaluation. In Pengrowth s structure, the CEO is compensated through the Management Agreement with Pengrowth Management. The charter for Pengrowth s Compensation Committee recognizes this distinction and requires the committee to review the performance of the Manager and review and consider the terms of the Management Agreement, where appropriate to enter into discussions with the Manager as to amendments or changes to the Management Agreement that are in the interests of Unitholders and to set annual performance targets and plans in connection therewith.

The NYSE Listed Company Manual requires shareholder approval of all equity compensation plans and any material revisions to such plans, regardless of whether the security is to be delivered under such plans are newly issued or purchased on the open market, subject to a few limited exceptions. In contrast, the TSX rules require shareholder approval of equity compensation plans only when such plans involve newly issued securities. If the plan provides a procedure for its amendment, the TSX rules require shareholder approval of amendments only where the amendment involves a reduction in the exercise price or an extension of the term of options held by insiders. As a matter or practice, Pengrowth has obtained the approval of its Unitholders to all of its equity compensation plans, regardless of whether the Trust Units to be delivered under such plans are newly issued or purchased on the open market.

The NYSE Listed Company Manual requires that the charters of the nominating/corporate governance committee, the audit committee and the compensation committee require an annual performance evaluation of the committee. In addition, the NYSE Listed Company Manual suggests that an issuer s corporate governance guidelines include a requirement for the board to conduct a self-evaluation at least annually. While Pengrowth s charters for these committees does not require those committees to perform an annual performance evaluation nor does the Pengrowth s Corporate Governance Policy require the board to conduct annual self-evaluation, the charter of the Corporate Governance Committee includes the mandate to assess the effectiveness of the board and its committees.

The NYSE Listed Company Manual requires the written charter of the compensation committee to provide that the committee must produce a compensation committee report on executive officer compensation for inclusion in the issuer s annual information circular or annual report. While the Terms of Reference of Pengrowth s Compensation Committee does not require such a report, in accordance with applicable Canadian securities laws Pengrowth s annual Information Circular Proxy Statement contains a report on executive compensation, which is reviewed and approved by the Compensation Committee.

The NYSE Listed Company Manual requires the written charter of the audit committee to provide that the audit committee must prepare a report to be included in the issuer s annual information circular. There is no requirement under Canadian law or under Pengrowth s audit committee charter to prepare such a report, and it is not Pengrowth s current practice to prepare such a report. However, read together, the disclosure contained in Pengrowth s Information Circular Proxy Statement under the heading Part II Corporate Governance , Pengrowth s Annual Report under the headings Corporate Responsibility , Corporate Governance Practices and Structure and Function , and herein under the heading Audit Committee provides the substance of the disclosure mandated by the NYSE rule.

ADDITIONAL INFORMATION

Additional information, including the Manager s remuneration and the principal holders of Trust Units, is contained in the Information Circular Proxy Statement of the Corporation and Pengrowth Trust dated March 14, 2005, which relates to the Annual and Special Meeting of Unitholders, and the Annual and Special Meeting of shareholders of the Corporation and the Special Meeting of holders of royalty units held on April 26, 2005. Additional financial information is contained in the Trust s comparative financial statements for the years ended December 31, 2005 and 2004 which are included in the Trust s Annual Report for the year ended December 31, 2005.

Additional information relating to Pengrowth Energy Trust may be found on SEDAR at www.sedar.com.

For additional copies of the Annual Information Form and the materials listed in the preceding paragraphs please contact:

Investor Relations
Pengrowth Energy Trust
Suite 2900, 240 4th Ave S.W.
Calgary, Alberta T2P 4H4
Telephone: (403) 233-0224
1-800-223-4122
Fax: (403) 294-0051

Toronto Investor Relations
Scotia Plaza, 40 King Street West
Suite 3006, Box 106
Toronto, Ontario M5H 3Y2
Telephone: (416) 362-1748
1-888-744-1111
Fax: (416) 362-8191

Website: www.pengrowth.com
E-mail: investorrelations@pengrowth.com

APPENDIX A
Report On Reserves Data By Independent
Qualified Reserves Evaluations On Form 51-101F2

**REPORT ON RESERVES DATA
BY
INDEPENDENT QUALIFIED RESERVES
EVALUATOR OR AUDITOR**

To the board of directors of Pengrowth Corporation (the Company):

1. We have prepared an evaluation of the Company 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 Company 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 Company 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 Company s board of directors:

Independent Qualified Reserves Evaluator	Description and Preparation Date of Evaluation Report	Location of Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate - $M) Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants	January 16, 2006	Canada		$ 3,204,481		$ 3,204,481

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 our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

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

EXECUTED as to our report referred to above:
GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, February 17, 2006

Doug R. Sutton, P. Eng.
VP Corporate Evaluations

APPENDIX B
Report Of Management And Directors On
Oil And Gas Disclosure On Form 51-101F3
B-1

FORM 51-101F3
REPORT OF
MANAGEMENT AND DIRECTORS
ON OIL AND GAS DISCLOSURE

Management of the Corporation (the Company) is responsible for the preparation and disclosure of information with respect to the oil and gas activities of Pengrowth Energy Trust (the Pengrowth Trust) 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

(i) 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

(i) the related estimated future net revenue.

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

The Reserves Committee of the board of directors of the Company has

(c) reviewed the Company s procedures for providing information to the independent qualified reserves evaluator;

(d) 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

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

The Reserves Committee of the board of directors has reviewed the Company 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, on the recommendation of the Reserves Committee, approved

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

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

(h) the content and filing of this report.

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

James S. Kinnear

James S. Kinnear
Chairman, President and Chief Executive Officer
Pengrowth Corporation

William G. Christensen

William G. Christensen
Vice President, Strategic Planning and Reservoir Exploitation
Pengrowth Corporation

Stanley H. Wong

Stanley H. Wong
Director
Pengrowth Corporation

Kirby L. Hedrick

Kirby L. Hedrick
Director
Pengrowth Corporation

March 29, 2006

APPENDIX C
Audit Committee Charter
C-1

CHARTER OF THE AUDIT COMMITTEE OF THE
BOARD OF DIRECTORS OF PENGROWTH CORPORATION (THE COMPANY)
JULY 30, 2001
AND AMENDED AND RESTATED MARCH 28, 2006

I. Audit Committee purpose:

The Audit Committee is appointed by the Board of Directors to assist the Board in fulfilling its oversight responsibilities. The Audit Committee s primary duties and responsibilities are to:

Monitor the performance of the Company s internal audit function and the integrity of the Company s financial reporting process and systems of internal controls regarding finance, accounting, and legal compliance.

Monitor the independence and performance of the Company s external auditors.

Provide an avenue of communication among the external auditors, the internal auditors, management and the Board of Directors.

The Audit Committee has the authority to conduct any investigation appropriate to fulfilling its responsibilities, and it has direct access to the internal and external auditors as well as anyone in the organization. The Audit Committee has the ability to retain, at the Company s expense, special legal, accounting, or other consultants or experts it deems necessary in the performance of its duties, and has the authority to set and pay the compensation for any such advisors employed by the Corporation.

II. Audit Committee Composition and Meetings

Audit Committee members shall meet the requirements of applicable securities laws and the stock exchanges on which Pengrowth Energy Trust trades. The Audit Committee shall be comprised of three or more directors as determined by the Board, each of whom shall be independent and financially literate , as those terms are defined in Multilateral Instrument 52-110 Audit Committees of the Canadian Securities Administrators.

Audit Committee members shall be appointed by the Board. If an audit committee Chair is not designated or present, the members of the Committee may designate a Chair by majority vote of the Committee membership.

The Committee shall meet at least four times annually, or more frequently as circumstances dictate. The Audit Committee Chair shall prepare and/or approve an agenda in advance of each meeting. The Committee should meet privately in executive sessions at least annually with management, the internal auditors and the external auditors and as a Committee to discuss any matters that the Committee, management, the internal auditors or the external auditors believe should be discussed. In addition, the Committee, or at least its Chair, should communicate with management, the internal auditors and the external auditors quarterly to review the Company s financial statements and significant findings based upon the auditors limited review procedures.

III. Audit Committee Responsibilities and Duties

Review Procedures

1. Review and reassess the adequacy of this Charter at least annually. Submit the Charter to the Board of Directors for approval and have the document published at least every three years in accordance with SEC regulations.

2. Review the Company s annual audited financial statements, management s discussion and analysis and annual and interim earnings press releases prior to filing or public distribution. This review

should include discussions with management, the internal auditors and the external auditors of significant issues regarding accounting principles, practices and judgements.

3. In consultation with management, the internal auditors and the external auditors, consider the integrity of the Company s financial reporting processes and controls and the performance of the Company s internal financial accounting staff. Discuss significant financial risk exposures and the steps management has taken to monitor, control and report such exposures. Review significant findings prepared by the internal or external auditors together with management s responses.

4. Review with financial management, the internal auditors and the external auditors the Company s quarterly financial results and accompanying management s discussion and analysis prior to the release of earnings and/or the Company s quarterly financial statements prior to filing or public distribution. Discuss any significant changes to the Company s accounting principles and any items required to be communicated by the external auditors in accordance with Assurance and Related Services Guideline #11 (AuG-11) (see item 10).

5. Review with financial management, the internal auditors and the external auditors the Company s policies relating to risk management and risk assessment.

6. Meet separately with each of management of the Company, the internal auditors and with the external auditors to discuss difficulties or concerns, specifically: (i) any difficulties encountered in the course of the audit work, including any restrictions on the scope of activities or access to requested information, and any significant disagreements with management; (ii) any changes required in the planned scope of the audit; and (iii) the responsibilities, budget, and staffing of the internal audit function, and report to the Board of Directors on such meetings.

Internal Auditors

7. Review the annual audit plans of the internal auditors.

8. Review the significant findings prepared by the internal auditors and recommendations issued by any external party relating to internal audit issues, together with management s response thereto.

9. Review the adequacy of the resources of the internal auditors to ensure the objectivity and independence of the internal audit function.

10. Consult with management on management s appointment, replacement, reassignment or dismissal of the internal auditors.

11. Ensure that the internal auditors have access to the Chair, the Chair of the Board of Directors and the Chief Executive Officer.

External Auditors

12. The external auditors are ultimately accountable to the Audit Committee and the Board of Directors. The Audit Committee is directly responsible for overseeing the work of the external auditors, shall review the independence and performance of the external auditors and shall annually recommend to the Board of Directors the appointment of the external auditors or approve any discharge of auditors when circumstances warrant. The Audit Committee shall, on an annual basis, obtain and review a report by the external auditor describing: (i) the Company s internal quality control procedures; (ii) any material issues raised by the most recent internal quality control review, or peer review, of the Company, or by an inquiry or investigation by governmental or professional authorities, within the preceding five years, respecting one or more independent audits carried out by the Company, and any steps taken to deal with any such issues; and (iii) all relationships between the independent auditor and the Company.

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13. Approve the fees and other significant compensation to be paid to the external auditors.

14. Pre-approve all non-audit services to be provided to the Company or its subsidiary entities by the Company s external auditors.

15. On an annual basis, the Committee should review and discuss with the external auditors all significant relationships they have with the Company that could impair the auditors independence.

16. The Committee shall review the external auditors audit plan discuss scope, staffing, locations, and reliance upon management and general audit approach.

17. Prior to releasing the year-end earnings, discuss the results of the audit with the external auditors.

18. Consider the external auditors judgments about the quality and appropriateness of the Company s accounting principles as applied in its financial reporting.

19. Be responsible for the resolution of disagreements between management and the external auditors regarding financial performance.

<u>Other Audit Committee Responsibilities</u>

20. Establish procedures for: (i) the receipt, retention and treatment of complaints received by the Company regarding accounting, internal accounting controls, or auditing matters; and (ii) the confidential and anonymous submission by employees of the Company of concerns regarding questionable accounting or auditing matters.

21. Review and approve the Company s hiring policies regarding partners, employees and former partners and employees of the present and former external auditors of the Company.

22. On at least an annual basis, review with the Company s counsel, any legal matters that could have a significant impact on the organization s financial statements, the Company s compliance with applicable laws and regulations, and inquiries received from regulators or governmental agencies.

23. Annually prepare a report to shareholders as required by the Securities and Exchange Commission. The report should be included in the Company s annual proxy statement.

24. Perform any other activities consistent with this Charter, the Company s by-laws, and governing law as the Committee or the Board deems necessary or appropriate.

25. Maintain minutes of meetings and periodically report to the Board of Directors on significant results of the foregoing activities.

APPENDIX B
MANAGEMENT S DISCUSSION AND ANALYSIS
(INCLUDED ON PAGES 54 THROUGH 80 OF THE PENGROWTH ENERGY TRUST 2005 ANNUAL REPORT)

Management s Discussion and Analysis

The following discussion and analysis of financial results should be read in conjunction with the audited consolidated financial statements for the year ended December 31, 2005 and is based on information available to February 27, 2006.

Frequently Recurring Terms

For the purposes of this Management s Discussion and Analysis, we use certain frequently recurring terms as follows: the Trust refers to Pengrowth Energy Trust, the Corporation refers to Pengrowth Corporation, Pengrowth refers to the Trust and the Corporation on a consolidated basis and the Manager refers to Pengrowth Management Limited.

Advisory Regarding Forward-Looking Statements

This Management s Discussion and Analysis contains forward-looking statements within the meaning of securities laws, including the safe harbour provisions of the Ontario *Securities Act* and the United States *Private Securities Litigation Reform Act of 1995*. Forward-looking information is often, but not always, identified by the use of words such as anticipate , believe , expect , plan , intend , forecast , target , project , may , will , should , c
similar words suggesting future outcomes or language suggesting an outlook. Forward-looking statements in this Management s Discussion and Analysis include, but are not limited to, statements with respect to: reserves, average 2006 production, production additions from Pengrowth s 2006 development program, the impact on production of divestitures in 2006, total operating expenses for 2006, 2006 operating expenses per boe, capital expenditures for 2006 and the breakdown of such capital expenditures for drilling, facilities and maintenance, land and seismic

Historical Annual Compound Returns by Year

(%)

Note: Assumes reinvestment of distributions in the trust at month end.

* Weighted average of Class A trust units (NYSE) and Class B trust units (TSX).

acquisition and re-completions, work-overs and CO_2 pilot. Statements relating to reserves are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the reserves described exist in the quantities predicted or estimated and can profitably be produced in the future. Forward-looking statements and information are based on Pengrowth s current beliefs as well as assumptions made by and information currently available to Pengrowth concerning anticipated financial performance, business prospects, strategies and regulatory developments. Although management considers these assumptions to be reasonable based on information currently available to it, they may prove to be incorrect.

By their very nature, forward-looking statements involve inherent risks and uncertainties, both general and specific, and risks that predictions, forecasts, projections and other forward-looking statements will not be achieved. We caution readers not to place undue reliance on these statements as a number of important factors could cause the actual results to differ materially from the beliefs, plans, objectives, expectations and anticipations, estimates and intentions expressed in such forward-looking statements. These factors include, but are not limited to: the volatility of oil and gas prices; production and development costs and capital expenditures; the imprecision of reserve estimates and estimates of recoverable quantities of oil, natural gas and liquids; Pengrowth s ability to replace and expand oil and gas reserves; environmental claims and liabilities; incorrect assessments of value when making acquisitions; increases in debt service charges; the loss of key personnel; the marketability of production; defaults by third party operators; unforeseen title defects; fluctuations in foreign currency and exchange rates; inadequate insurance coverage; compliance with environmental laws and regulations; changes in tax laws; the failure to qualify as a mutual fund trust; and Pengrowth s ability to access external sources of debt and equity capital. Further information regarding these factors may be found under the heading Business Risks herein and under Risk Factors in Pengrowth s Annual Information Form which will be available on SEDAR at www.sedar.com on or before March 31, 2006.

Pengrowth cautions that the foregoing list of factors that may affect future results is not exhaustive. When relying on our forward-looking statements to make decisions with respect to Pengrowth, investors and others should carefully consider the foregoing factors and other uncertainties and potential events. Furthermore, the forward-looking statements contained in this Management s Discussion and Analysis are made as of the date of this Management s Discussion and Analysis and Pengrowth does not undertake any obligation to up-date publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained in this Management s Discussion and Analysis are expressly qualified by this cautionary statement.

Critical Accounting Estimates

As discussed in Note 2 to the financial statements, the financial statements are prepared in accordance with Canadian Generally Accepted Accounting Principles (GAAP). Management is required to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and revenues and expenses for the period then ended.

The amounts recorded for depletion, depreciation and amortization of injectants and the provision for asset retirement obligations are based on estimates. The ceiling test calculation is based on estimates of proved reserves, production rates, oil and natural gas prices, future costs and other relevant assumptions. As required by National Instrument 51-101 (NI 51-101), Pengrowth uses independent qualified reserve evaluators in the preparation of reserve evaluations. By their nature, these estimates are subject to measurement uncertainty and changes in these estimates may impact the consolidated financial statements of future periods.

Non-GAAP Financial Measures

This discussion and analysis refers to certain financial measures that are not determined in accordance with GAAP in Canada or the United States. These measures do not have standardized meanings and may not be comparable to similar measures presented by other trusts or corporations. Measures such as distributable cash, distributable cash per trust unit, payout ratio and operating netbacks do not have standardized meanings prescribed by GAAP. During the second quarter of 2005, Pengrowth s withholding practice and presentation of distributable cash changed. The impact of the new practice is discussed in the Distributable Cash, Distributions and Taxability of Distributions section of this report on pages 69 to 70, while the remaining non-GAAP measures are determined by reference to our financial statements. We discuss these measures because we believe that they facilitate the understanding of the results of our operations and financial position.

Conversion and Currency

When converting natural gas to equivalent barrels of oil within this discussion, Pengrowth uses the international standard of six thousand cubic feet (mcf) to one barrel of oil equivalent. Barrels of oil equivalent may be misleading, particularly if used in isolation; a conversion ratio of six mcf of natural gas to one boe is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Production volumes, revenues and reserves are reported on a company interest gross basis (before royalties) in accordance with Canadian practice. All amounts are stated in Canadian dollars unless otherwise specified.

Year 2005 Overview

Pengrowth achieved record net income and cash generated from operations for 2005.

Robust commodity prices, a full year of production from the 2004 Murphy acquisition and additional production from the Swan Hills Unit No.1 (Swan Hills) and Crispin Energy Inc. (Crispin) acquisitions, which closed on February 28, 2005 and April 29, 2005, respectively, combined to have a favorable impact on 2005 financial and operating results relative to 2004. Financial hedging losses of $65.8 million on crude oil and natural gas offset some of the positive impact of the high commodity prices during the year as did the three percent depreciation of the U.S. dollar relative to the Canadian dollar.

Highlights

Oil and gas sales increased 41 percent to $1.15 billion in 2005 resulting in record net income of $326 million, an increase of 112 percent over 2004.

Production for 2005 averaged 59,357 barrels of oil equivalent (boe) per day, an increase of more than ten percent versus 2004. Fourth quarter production averaged 61,442 boe per day, an increase of four percent over the previous quarter and seven percent over the comparable period in 2004.

Distributable cash reached a new high in 2005 at $620 million, an increase of 54 percent over 2004. Fourth quarter distributable cash increased 87 percent versus 2004 to $196 million, the highest level of distributable cash generated in any quarter in Pengrowth s history.

Distributions paid or declared to unitholders increased 23 percent to $446 million or $2.82 per trust unit in 2005 from $363 million or $2.63 per trust unit in 2004. Pengrowth s monthly distribution was increased in December 2005 to an annualized rate of $3.00 per trust unit.

Pengrowth s payout ratio to unitholders for the full year and fourth quarter of 2005 reached record lows of 72 percent and 61 percent of cash generated from operations, respectively.

Pengrowth s 2005 development expenditures were essentially fully funded through withholdings from distributable cash.

During the year Pengrowth spent a combined total of $176 million on maintenance and development projects ending the year with proved plus probable (P50) reserves of 219.4 million barrels of oil equivalent (mmboe) compared to 218.6 mmboe at year end 2004. Pengrowth s P50 reserves were replaced through the addition of 16.7 mmboe related to acquisitions and 8.6 mmboe resulting from drilling activity, improved recoveries and technical revisions. Additions were offset by production of 21.7 mmboe and divestitures of 2.8 mmboe.

Pengrowth s average realized commodity price (after hedging) increased 28 percent to $53.02 per boe in 2005, from $41.33 in 2004.

Operating netbacks increased 33 percent to $32.54 per boe (after hedging) versus $24.51 per boe in 2004.

Combined hedging losses totaled $3.04 per boe in 2005 versus $3.52 per boe in 2004.

On February 28, 2005, Pengrowth acquired an additional 11.89 percent working interest in the Swan Hills property for $87 million. This acquisition increased Pengrowth s total interest in the property to 22.34 percent.

On April 29, 2005, Pengrowth successfully completed the acquisition of all of the issued and outstanding shares of Crispin adding approximately 1,900 boe per day of production to our portfolio.

On December 1, 2005, Pengrowth completed a £50 million private placement of senior unsecured ten year notes.

As at December 31, 2005, Pengrowth had generated a combined three-year weighted average compound total return of 36 percent per annum for Class A and Class B unitholders.

Summary of Financial and Operating Results

(thousands, except per unit amounts)	Three months ended December 31 2005	2004	% Change	Twelve months ended December 31 2005	2004	% Change
INCOME STATEMENT						
Oil and gas sales	**$ 353,923**	$ 223,183(2)	59	**$ 1,151,510**	$ 815,751(2)	41
Net income	**$ 116,663**	$ 31,138	275	**$ 326,326**	$ 153,745	112
Net income per trust unit	**$ 0.73**	$ 0.23	217	**$ 2.08**	$ 1.15	81
Cash generated from operations	**$ 196,588**	$ 93,287	111	**$ 618,070**	$ 404,167	53
Cash generated from operations per trust unit	**$ 1.23**	$ 0.68	81	**$ 3.93**	$ 3.03	30
Distributable cash (1)	**$ 195,879**	$ 104,958(2)	87	**$ 619,739**	$ 401,178(2)	54
Distributable cash per trust unit (1)	**$ 1.23**	$ 0.77	60	**$ 3.94**	$ 3.01	31
Distributions paid or declared	**$ 119,858**	$ 96,466	24	**$ 445,977**	$ 363,061	23
Distributions paid or declared per trust unit	**$ 0.75**	$ 0.69	9	**$ 2.82**	$ 2.63	7
Weighted average number of trust units outstanding	**159,528**	136,916	17	**157,127**	133,395	18
BALANCE SHEET						
Working capital				**$ (112,205)**	$ (78,546)	43
Property, plant and equipment and other assets				**$ 2,067,988**	$ 1,989,288	4
Long term debt				**$ 368,089**	$ 345,400	7
Unitholders equity				**$ 1,475,996**	$ 1,462,211	1
Unitholders equity per trust unit				**$ 9.23**	$ 9.56	(3)
Number of trust units outstanding at year end				**159,864**	152,973	5
DAILY PRODUCTION						
Crude oil (barrels)	**21,179**	20,118	5	**20,799**	20,817	0
Heavy oil (barrels)	**5,410**	5,819	(7)	**5,623**	3,558	58
Natural gas (mcf)	**168,862**	156,621	8	**161,056**	144,277	12
Natural gas liquids (barrels)	**6,710**	5,385	25	**6,093**	5,281	15
Total production (boe)	**61,442**	57,425	7	**59,357**	53,702	10
Total production (mboe)	**5,653**	5,283	7	**21,665**	19,655	10
PRODUCTION PROFILE						
Crude oil	**34%**	35%		**35%**	39%	
Heavy oil	**9%**	10%		**10%**	6%	
Natural gas	**46%**	46%		**45%**	45%	
Natural gas liquids	**11%**	9%		**10%**	10%	
AVERAGE REALIZED PRICES (AFTER HEDGING)						
Crude oil (per barrel)	**$ 59.40**	$ 44.76	33	**$ 58.59**	$ 43.21	36

Heavy oil (per barrel)	**$**	**31.77**	$	26.99	18	**$**	**33.32**	$	32.45	3
Natural gas (per mcf)	**$**	**11.97**	$	7.02	71	**$**	**8.76**	$	6.80	29
Natural gas liquids (per barrel)	**$**	**58.46**	$	48.04	22	**$**	**54.22**	$	42.21	28
Average realized price per boe	**$**	**62.55**	$	42.08(2)	49	**$**	**53.02**	$	41.33(2)	28
PROVED PLUS PROBABLE RESERVES										
Crude oil (mbbls)							**98,684**		94,066	5
Heavy oil (mbbls)							**15,790**		18,245	(13)
Natural gas (bcf)							**516**		521	(1)
Natural gas liquids (mbbls)							**18,985**		19,395	(2)
Total oil equivalent (mboe)							**219,396**		218,613	0

(1) See the section entitled Non-GAAP Financial Measures

(2) Restated to conform to presentation adopted in the current year

Results of Operations

Production

Average daily production increased over ten percent in 2005 compared to 2004. The increase is attributable primarily to the Murphy, Swan Hills and Crispin acquisitions and contributions from ongoing development activities. At this time, Pengrowth is forecasting average 2006 production of 54,000 to 56,000 boe per day from existing assets. This estimate incorporates anticipated production additions from planned 2006 development activities. Offsetting these additions are previously disclosed divestitures of approximately 1,300 boe per day in the first quarter of 2006, which have been excluded from the above estimate, including the divestment of approximately 1,000 boe per day related to the Monterey Exploration Ltd. (Monterey) transaction announced on January 12, 2006 and expected production declines from normal operations. The above estimate specifically excludes the potential impact of any other future acquisitions or divestitures.

Daily Production

	Three months ended			Twelve months ended	
	Dec. 31, 2005	Sep. 30, 2005	Dec. 31, 2004	**Dec. 31, 2005**	Dec. 31, 2004
Light crude oil (bbls) [1]	**21,179**	20,660	20,118	**20,799**	20,817
Heavy oil (bbls) [1]	**5,410**	5,405	5,819	**5,623**	3,558
Natural gas (mcf)	**168,862**	164,288	156,621	**161,056**	144,277
Natural gas liquids (bbls) [1]	**6,710**	5,448	5,385	**6,093**	5,281
Total boe per day	**61,442**	58,894	57,425	**59,357**	53,702

[1] bbls refers to barrels

Light crude oil production volumes remained relatively flat year-over-year due to the positive impact of production related to the Swan Hills and Crispin acquisitions which largely offset natural production declines. Improved miscible flood response at Judy Creek contributed to most of the three percent increase in production in fourth quarter 2005 versus the third quarter of 2005.

Heavy oil production increased 58 percent year-over-year due to the inclusion of a full 12 months of production volumes from properties acquired in the Murphy acquisition which closed on May 31, 2004. The seven percent decrease in production for the fourth quarter of 2005 compared to the fourth quarter of 2004 is attributable to natural production declines.

Natural gas production increased 12 percent year-over-year. Additional production volumes from the Murphy and Crispin acquisitions and ongoing development activities, particularly the Monogram infill drilling program completed in the fourth quarter of 2004, combined to more than offset natural production declines. The three percent increase in volumes in the fourth quarter of 2005 compared to the third quarter of 2005 is due largely to a 44 well drilling program at Princess which was completed during the fourth quarter. Fourth quarter 2005 volumes were eight percent higher than fourth quarter 2004 volumes primarily due to the Crispin acquisition, new wells at Princess and Sable Offshore Energy Project (SOEP) and lower residue gas solvent demand at Judy Creek allowing for increased sales.

Natural gas liquids (NGLs) production increased 15 percent year-over-year primarily due to the timing and size of condensate sales from SOEP. Pengrowth received six shipments (two shipments in the fourth quarter) from SOEP in 2005 compared to four shipments in the previous year.

Pricing and Commodity Price Hedging

The increase in U.S. based prices for North American crude oil and natural gas was partially offset by the negative impact of the rising Canadian dollar relative to the U.S. dollar and hedging losses.

Average Realized Prices

(Cdn$)	**Three months ended**			**Twelve months ended**	
	Dec. 31, 2005	Sep. 30, 2005	Dec. 31, 2004	**Dec. 31, 2005**	Dec. 31, 2004
Light crude oil (per bbl)	**67.00**	74.37	55.24	**65.47**	50.72
after hedging	**59.40**	63.95	44.76	**58.59**	43.21
Heavy oil (per bbl)	**31.77**	47.74	26.99	**33.32**	32.45
Natural gas (per mcf)	**12.80**	8.69	7.25	**8.99**	7.03
after hedging	**11.97**	8.57	7.02	**8.76**	6.80
Natural gas liquids (per bbl)	**58.46**	57.75	48.04	**54.22**	42.21
Total per boe	**67.43**	60.06	46.38(3)	**56.06**	44.85(3)
after hedging	**62.55**	56.07	42.08(3)	**53.02**	41.33(3)
Benchmark Prices					
WTI oil (U.S. $ per bbl)	**60.05**	63.31	48.27	**56.70**	41.47
AECO spot gas (Cdn $ per gj) (1)	**11.08**	7.75	6.72	**8.04**	6.44
NYMEX gas (U.S. $ per mmbtu)(2)	**12.97**	8.49	7.11	**8.62**	6.16
Currency (U.S. $/Cdn $)	**0.85**	0.83	0.82	**0.83**	0.77

(1) gj refers to gigajoules

(2) mmbtu refers to millions of British thermal units

(3) Prior years restated to conform to presentation adopted in current year

As part of our financial management strategy, Pengrowth uses forward price swap and option contracts to manage its exposure to commodity price fluctuations, to provide a measure of stability to monthly cash distributions and to partially secure returns on significant new acquisitions.

Hedging Losses

	Three months ended			**Twelve months ended**	
	Dec. 31, 2005	Sep. 30, 2005	Dec. 31, 2004	**Dec. 31, 2005**	Dec. 31, 2004
Light crude oil ($ million)	**14.8**	19.8	19.4	**52.2**	57.2
Light crude oil ($ per bbl)	**7.60**	10.42	10.48	**6.88**	7.51

Natural gas ($ million)	**12.9**	1.8	3.3	**13.6**	11.9
Natural gas ($ per mcf)	**0.83**	0.12	0.23	**0.23**	0.23
Combined ($ million)	**27.7**	21.6	22.7	**65.8**	69.1
Combined ($ per boe)	**4.88**	3.99	4.30	**3.04**	3.52

Commodity price hedges in place at December 31, 2005 are provided in Note 17 to the financial statements. As of February 27, 2006, Pengrowth has not entered into any additional contracts subsequent to year end.

In conjunction with the Murphy acquisition, Pengrowth assumed certain fixed price natural gas sales contracts and firm pipeline demand charge contracts associated with the Murphy reserves. Under these contracts, Pengrowth is obligated to sell 3,886 mmbtu per day, until April 30, 2009 at an average remaining contract price of Cdn $2.31 per mmbtu. As required by GAAP, the fair value of the natural gas sales contract was recognized as a liability based on the mark-to-market value at May 31, 2004. The liability at December 31, 2005 of $18.2 million for the contracts will continue to be drawn down and recognized in income as the contracts are settled. As this is a non-cash component of income, it is not included in the calculation of distributable cash. At December 31, 2005, the mark-to-market value of the fixed price physical sales contract represented a potential loss of $35.3 million.

Oil and Gas Sales Contribution Analysis

($ millions)			**Three months ended**						**Twelve months ended**		
Sales Revenue	**Dec. 31, 2005**	**% of total**	Sep. 30, 2005	% of total	Dec. 31, 2004	% of total	**Dec. 31, 2005**	**% of total**	Dec. 31, 2004	% of total
Natural gas	**186.0**	**53**	129.5	43	101.2	45	**514.9**	**45**	359.3	44
Light crude oil	**115.7**	**33**	121.6	40	82.8	37	**444.8**	**39**	329.2	40
Natural gas liquids	**36.1**	**10**	28.9	9	23.8	11	**120.6**	**10**	81.6	10
Heavy oil	**15.8**	**4**	23.7	8	14.5	7	**68.4**	**6**	42.3	5
Brokered sales/sulphur	**0.3**		0.8		0.9		**2.8**		3.4	1
Total oil and gas sales	**353.9**		304.5		223.2		**1,151.5**		815.8	

Oil and Gas Sales Price and Volumes Analysis

The following table illustrates the effect of changes in prices and volumes on the components of oil and gas sales, including the impact of hedging.

($ millions)	**Natural gas**	**Light oil**	**NGLs**	**Heavy oil**	**Other**	**Total**
Year ended December 31, 2004	359.3	329.2	81.6	42.3	3.4	815.8
Effect of change in product prices	115.3	112.0	26.7	1.8		255.8
Effect of change in sales volumes	42.0	(1.4)	12.3	24.3		77.2
Effect of hedging losses	(1.7)	5.0				3.3
Other					(0.6)	(0.6)
Year ended December 31, 2005	514.9	444.8	120.6	68.4	2.8	1,151.5

Transportation Costs

($ millions)	Three months ended			Twelve months ended	
	Dec. 31, 2005	Sep. 30, 2005	Dec. 31, 2004	**Dec. 31, 2005**	Dec. 31, 2004
Light oil transportation	**0.5**	0.6	0.4	**2.2**	1.8
$ per bbl	**0.27**	0.29	0.23	**0.29**	0.23
Natural gas transportation	**1.8**	1.4	2.0	**5.7**	6.3
$ per mcf	**0.12**	0.09	0.14	**0.10**	0.12

Pengrowth incurs transportation costs for its product once the product enters a feeder or main pipeline to the title transfer point. The transportation cost is dependant upon industry rates and distance the product flows on the pipeline prior to changing ownership or custody. Pengrowth has the option to sell some of its natural gas directly to premium markets outside of Alberta by incurring additional transportation costs. In 2005, Pengrowth sold most of its natural gas without incurring significant additional transportation costs. Similarly, Pengrowth has elected to sell approximately 75 percent of its crude oil at market points beyond the wellhead, but at the first major trading point, requiring minimal transportation costs.

Royalties

($ millions)	Three months ended			Twelve months ended	
	Dec. 31, 2005	Sep. 30, 2005	Dec. 31, 2004	**Dec. 31, 2005**	Dec. 31, 2004
Royalty expense	**68.0**	57.4	49.1	**213.9**	160.4
$ per boe	**12.03**	10.60	9.29	**9.87**	8.16
Royalties as a percent of sales	**19.2%**	18.9%	22.0%	**18.6%**	19.7%

Royalties include crown, freehold and overriding royalties as well as mineral taxes. A lesser credit for enhanced oil recovery relief at Judy Creek had an unfavorable impact to royalties in the fourth quarter of 2004 as solvent injection costs were lower than anticipated.

Processing, Interest and Other Income

($ millions)	Three months ended			Twelve months ended	
	Dec. 31, 2005	Sep. 30, 2005	Dec. 31, 2004	**Dec. 31, 2005**	Dec. 31, 2004
Processing, interest & other income	**4.0**	2.1	4.5	**17.7**	14.2
$ per boe	**0.71**	0.39	0.83	**0.82**	0.72

Processing, interest and other income is primarily derived from fees charged for processing and gathering third party gas, road use, and oil and water processing. This income represents the partial recovery of operating expenses included below in Operating Expenses.

Operating Expenses

($ millions)	Three months ended			Twelve months ended	
	Dec. 31, 2005	Sep. 30, 2005	Dec. 31, 2004	**Dec. 31, 2005**	Dec. 31, 2004
Operating expenses	**61.2**	57.4	42.6	**218.1**	159.7
$ per boe	**10.83**	10.59	8.06	**10.07**	8.13

Operating expenses increased year-over-year as a result of timing of acquisitions partway through 2004 and in 2005 which impacted costs by approximately $30 million. Additionally, there was general pressure on goods and services in the oil and gas industry during 2005, with year-over-year increases of more than ten percent within most of these areas. Utility costs also increased approximately $10 million year-over-year. Operating expenses include costs incurred to earn processing and other income reported above in Processing, Interest and Other Income.

Amortization of Injectants for Miscible Floods

($ millions)	Three months ended			Twelve months ended	
	Dec. 31, 2005	Sep. 30, 2005	Dec. 31, 2004	**Dec. 31, 2005**	Dec. 31, 2004
Purchased and capitalized	**14.5**	6.9	8.2	**34.7**	20.4
Amortization	**7.1**	6.0	4.9	**24.4**	19.7

The cost of injectants (primarily natural gas and ethane) purchased for injection in miscible flood programs is amortized over the period of expected future economic benefit. Prior to 2005, the expected future economic benefit from injection was estimated at 30 months, based on the results of previous flood patterns. Commencing in 2005, the response period for additional new patterns being developed is expected to be somewhat shorter relative to the historical miscible patterns in the project. Accordingly, the cost of injectants purchased in 2005 will be amortized over a 24 month period while costs incurred for the purchase of injectants in prior periods will continue to be amortized over 30 months. As of December 31, 2005, the balance of unamortized injectant costs was $35.3 million.

The value of Pengrowth s proprietary injectants is not recorded until reproduced from the flood and sold, although the cost of producing these injectants is included in operating expenses. Pengrowth currently anticipates similar injection volumes for Judy Creek and increased injection volumes for Swan Hills during 2006. This combined with higher forecast prices for natural gas and ethane is anticipated to result in increased total injectant costs for 2006.

Interest

Interest expense decreased by 28 percent to $21.6 million in 2005 from $29.9 million in 2004, reflecting a lower average debt level combined with lower standby fees. Standby fees in 2004 of $3.9 million were related to the set-up of bridge financing utilized for the 2004 Murphy acquisition. Imputed interest on the note payable to Emera Offshore Incorporated (Emera) was also recorded in the amount of $1.3 million (2004 $1.6 million).

The average interest rate on Pengrowth s long term debt outstanding at December 31, 2005 is 5.1 percent. Approximately 63 percent of Pengrowth s outstanding debt as at December 31, 2005 incurs interest expense payable in U.S. dollars and therefore remains subject to fluctuations in the U.S. dollar exchange rate. The note payable is non-interest bearing.

Foreign Currency Gains and Losses

Pengrowth recorded a net foreign exchange gain of $7.0 million in 2005, compared to a foreign exchange gain of $17.3 million in 2004. Included in the 2005 gain is a $7.8 million unrealized foreign exchange gain related to the U.S. dollar denominated debt. This gain arises as a result of the increase in the Canadian to U.S. dollar exchange rate in 2005 from a rate of approximately $0.83 at December 31, 2004 to a rate of approximately $0.86 at December 31, 2005. Offsetting this gain is a realized foreign exchange loss of $0.8 million related mainly to U.S. dollar denominated receivables. Revenues are recorded at the average exchange rate for the production month in which they accrue, with payment being received on or about the 25th of the following month. As a result of the increase in the Canadian dollar relative to the U.S. dollar over the course of the year, a foreign exchange loss was recorded to the extent that there was a difference between the average exchange rate for the month of production and the exchange rate at the date the payments were received on that portion of production sales that are received in U.S. dollars. Pengrowth has arranged a significant portion of its long term debt in U.S. dollars as a natural hedge against a stronger Canadian dollar, as the negative impact on oil and gas sales is somewhat offset by a reduction in the U.S. dollar denominated interest cost. (See Note 12 to the financial statements for further detail).

General and Administrative

($ millions)	**Three months ended**			**Twelve months ended**	
	Dec. 31, 2005	Sep. 30, 2005	Dec. 31, 2004	**Dec. 31, 2005**	Dec. 31, 2004
Cash G&A expense	**7.7**	7.0	6.5	**27.4**	22.1
$ per boe	**1.36**	1.29	1.23	**1.27**	1.12
Non-cash G&A expense	**0.8**	0.6	0.4	**2.9**	2.3
$ per boe	**0.14**	0.11	0.08	**0.13**	0.12
Total G&A ($ million)	**8.5**	7.6	6.9	**30.3**	24.4
Total G&A ($ per boe)	**1.50**	1.40	1.31	**1.40**	1.24

The cash component of General and Administrative (G&A) increased due to a number of factors including the addition of personnel and office space in conjunction with the Murphy acquisition as well as a general increase in expanded financial reporting, legal and regulatory costs from the growth in our unitholder base and increasing regulatory requirements including preparing for compliance with the Sarbanes-Oxley Act. The non-cash compensation expense is related to the value of trust unit options and rights (see Note 2 and Note 10 to the financial statements for details). Also included in 2005 G&A is $0.9 million (2004 $0.8 million) for estimated reimbursement of G&A expenses incurred by the Manager, pursuant to the management agreement.

Management Fees

($ million)	Three months ended			Twelve months ended	
	Dec. 31, 2005	Sep. 30, 2005	Dec. 31, 2004	**Dec. 31, 2005**	Dec. 31, 2004
Management Fee	**2.2**	1.6	1.4	**9.1**	6.8
Performance Fee	**2.2**	1.9	1.2	**6.9**	6.1
Total ($ million)	**4.4**	3.5	2.6	**16.0**	12.9
Total ($ per boe)	**0.77**	0.65	0.48	**0.74**	0.66

Under the current management agreement, which came into effect July 1, 2003 for two three-year terms ending June 30, 2009, the Manager will earn a performance fee if the Trust s total returns exceed eight percent per annum on a three year rolling average basis. At the end of the first term a review process will determine whether to extend the agreement for the second term. The maximum fees payable, including the performance fee, is limited to 80 percent of the fees that would otherwise have been payable under the previous management agreement for the first three years and 60 percent for the subsequent three years.

The Trust achieved a three year average total return of 36 percent per annum at the end of 2005; as a result the Manager earned the maximum fee payable under the new management agreement.

Related Party Transactions

Details of related party transactions incurred in 2005 and 2004 are provided in Note 15 to the financial statements. These transactions include the management fees paid to the Manager. The Manager is controlled by James S. Kinnear, the Chairman, President and Chief Executive Officer of the Corporation. The management fees paid to the Manager are pursuant to a management agreement which has been approved by the trust unitholders. Mr. Kinnear does not receive any salary or bonus in his capacity as a director and officer of the Corporation and has not received any new trust unit options or rights since November 2002.

Related party transactions in 2005 also include $0.7 million (2004 $0.8 million) paid to a law firm controlled by the Vice President and Corporate Secretary of Pengrowth Corporation, Charles V. Selby. These fees are paid in respect of legal and advisory services provided by the Vice President and Corporate Secretary. Mr. Selby does not receive any salary or bonus in his capacity as Vice President and Corporate Secretary of the Corporation. Mr. Selby has from time to time been granted trust unit rights and options.

Taxes

In determining its taxable income, the Corporation deducts payments made to the Trust, effectively transferring the income tax liability to unitholders thus reducing taxable income to nil. Under the Corporation s current distribution policy, funds are withheld from distributable cash to fund future capital expenditures and repay debt. As a result of increased amounts being withheld to fund capital spending, the Corporation could become subject to taxation on a portion of its income in the future. This can be mitigated through various options including the issuance of additional trust units, increased tax pools from additional capital spending, modifications to the distribution policy or changes to the corporate structure. As a result, the Corporation does not anticipate the payment of any cash income taxes in the foreseeable future.

Capital taxes paid or payable by the Corporation, based on debt and equity levels at the end of the year, amounted to $6.2 million in 2005 (2004 $4.6 million). This amount is comprised of Federal Large Corporations Tax of $2.2 million (2004 $1.3 million) and Saskatchewan Capital Tax and Resource Surcharge of $4.0 million (2004 $3.2 million). The increase in 2005 capital taxes is due to a higher taxable capital base from the Crispin acquisition and increased capital expenditures relative to 2004.

The corporate acquisition of Crispin in 2005 resulted in Pengrowth recording an additional future tax liability of $22.2 million. A $75.6 million future tax liability was initially recorded in 2004 as a result of the Murphy acquisition. The future tax liability represents the difference between the tax basis and the fair values assigned to the acquired assets. A comparison of the fair value and tax basis at the end of the year increased the future tax liability by $12.3 million to $110.1 million.

Depletion, Depreciation and Accretion

($ millions)	**Three months ended**			**Twelve months ended**	
	Dec. 31, 2005	Sep. 30, 2005	Dec. 31, 2004	**Dec. 31, 2005**	Dec. 31, 2004
Depletion and Depreciation	**71.4**	73.5	69.4	**285.0**	247.3
$ per boe	**12.63**	13.57	13.14	**13.15**	12.58
Accretion	**3.6**	3.6	3.2	**14.2**	10.6
$ per boe	**0.64**	0.66	0.60	**0.65**	0.54

Depletion and depreciation of property, plant and equipment and other assets is provided on the unit of production method based on total proved reserves. The provision for depletion and depreciation increased 15 percent in 2005 due to a larger depletable asset base and a higher depletion rate (production as a percentage of total proved reserves). Accretion increased 34 percent year-over-year due to a larger Asset Retirement Obligation (ARO).

Ceiling Test

Under Canadian GAAP, a ceiling test is applied to the carrying value of the property, plant and equipment and other assets. The carrying value is assessed to be recoverable when the sum of the undiscounted cash flows expected from the production of proved reserves, the lower of cost and market of unproved properties and the cost of major development projects exceeds the carrying value. When the carrying value is not assessed to be recoverable, an impairment loss is recognized to the extent that the carrying value of assets exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves, the lower of cost and market of unproved properties and the cost of major development projects. The cash flows are estimated using expected future product prices and costs and are discounted using a risk-free interest rate. There was a significant surplus in the ceiling test at year end 2005.

Asset Retirement Obligations

The total future ARO were estimated by management based on estimated costs to remediate, reclaim and abandon wells and facilities based on Pengrowth s working interest and the estimated timing of the costs to be incurred in future periods. Pengrowth has estimated the net present value of its total ARO to be $185 million as at December 31, 2005 (2004 $172 million), based on a total escalated future liability of $1,041 million (2004 $551 million). The significant change in the estimated future liability is due to increasing regulatory requirements, changing the economic life to agree with GLJ Petroleum Consultants Ltd. (GLJ) assumptions and increasing the future inflation rate. These costs are expected to be incurred over 50 years with the majority of the costs incurred between 2032 and 2054. Pengrowth s credit adjusted risk free rate of eight percent (2004 eight percent) and an inflation rate of 2.0 percent (2004 1.5 percent) were used to calculate the net present value of the ARO.

Remediation Trust Funds & Remediation and Abandonment Expenses

During 2005, Pengrowth contributed $1.3 million into trust funds established to fund certain abandonment and reclamation costs associated with Judy Creek and SOEP. The balance in these remediation trust funds was $8.3 million at December 31, 2005.

Pengrowth takes a proactive approach to managing its well abandonment and site restoration obligations. There is an on-going program to abandon wells and reclaim well and facility sites. In 2005, Pengrowth spent $7.4 million on abandonment and reclamation (2004 $4.4 million). Pengrowth expects to spend approximately $11 million per year, prior to inflation, over the next ten years on remediation and abandonment.

Goodwill

In accordance with Canadian GAAP, Pengrowth recorded goodwill of $12.2 million upon the Crispin acquisition in 2005 and $170.6 million upon the Murphy acquisition in 2004. The goodwill value was determined based on the excess of total consideration paid less the net value assigned to other identifiable assets and liabilities, including the future income tax liability. Details of the acquisitions are provided in Note 4 to the financial statements.

Netbacks

There is no standardized measure of operating netbacks and therefore operating netbacks, as presented below may not be comparable to similar measures presented by other companies. Certain assumptions have been made in allocating operating expenses, other production income, processing, interest and other income and royalty injection credits between light crude oil, heavy oil, natural gas and NGL production. Pengrowth recorded an operating netback of $32.54 per boe (after hedging) in 2005 compared to $24.51 (after hedging) in 2004, mainly due to higher average commodity prices in 2005 partially offset by higher operating expenses and royalties.

Combined Netbacks

($ per boe)	**Three months ended**			**Twelve months ended**	
	Dec. 31, 2005	Sep. 30, 2005	Dec. 31, 2004	**Dec. 31, 2005**	Dec. 31, 2004
Sales price	**62.55**	56.07	42.08	**53.02**	41.33
Other production income	**0.06**	0.13	0.17	**0.13**	0.17
	62.61	56.20	42.25	**53.15**	41.50
Processing, interest and other income	**0.71**	0.39	0.83	**0.82**	0.72
Royalties	**(12.02)**	(10.60)	(9.29)	**(9.87)**	(8.16)
Operating expenses	**(10.83)**	(10.59)	(8.07)	**(10.07)**	(8.13)
Transportation costs	**(0.41)**	(0.36)	(0.47)	**(0.36)**	(0.42)
Amortization of injectants	**(1.25)**	(1.10)	(0.94)	**(1.13)**	(1.00)
Operating netback	**38.81**	33.94	24.31	**32.54**	24.51

Light Crude Netbacks

($ per bbl)	Three months ended			Twelve months ended	
	Dec. 31, 2005	Sep. 30, 2005	Dec. 31, 2004	**Dec. 31, 2005**	Dec. 31, 2004
Sales price	**59.40**	63.95	44.76	**58.59**	43.21
Other production income	**0.17**	0.37	0.48	**0.37**	0.45
	59.57	64.32	45.24	**58.96**	43.66
Processing, interest and other income	**0.34**	0.64	0.51	**0.47**	0.46
Royalties	**(6.47)**	(11.03)	(9.65)	**(8.64)**	(7.62)
Operating expenses	**(14.32)**	(12.85)	(9.17)	**(12.28)**	(9.31)
Transportation costs	**(0.27)**	(0.29)	(0.23)	**(0.29)**	(0.23)
Amortization of injectants	**(3.63)**	(3.14)	(2.67)	**(3.21)**	(2.58)
Operating netback	**35.22**	37.65	24.03	**35.01**	24.38

Heavy Oil Netbacks

($ per bbl)	Three months ended			Twelve months ended	
	Dec. 31, 2005	Sep. 30, 2005	Dec. 31, 2004	**Dec. 31, 2005**	Dec. 31, 2004
Sales price	**31.77**	47.74	26.99	**33.32**	32.45
Processing, interest and other income	**0.74**	(0.83)		**0.36**	
Royalties	**(2.98)**	(8.00)	(4.19)	**(4.53)**	(4.87)
Operating expenses	**(11.60)**	(16.30)	(9.44)	**(15.65)**	(9.85)
Operating netback	**17.93**	22.61	13.36	**13.50**	17.73

Natural Gas Netbacks

($ per mcf)	Three months ended			Twelve months ended	
	Dec. 31, 2005	Sep. 30, 2005	Dec. 31, 2004	**Dec. 31, 2005**	Dec. 31, 2004

Sales price	**11.97**	8.57	7.02	**8.76**	6.80
Processing, interest and other income	**0.19**	0.09	0.24	**0.23**	0.20
Royalties	**(2.62)**	(1.47)	(1.34)	**(1.70)**	(1.26)
Operating expenses	**(1.38)**	(1.31)	(1.16)	**(1.24)**	(1.15)
Transportation costs	**(0.12)**	(0.09)	(0.14)	**(0.10)**	(0.12)
Operating netback	**8.04**	5.79	4.62	**5.95**	4.47

NGLs Netbacks

($ per bbl)	Three months ended			Twelve months ended	
	Dec. 31, 2005	Sep. 30, 2005	Dec. 31, 2004	**Dec. 31, 2005**	Dec. 31, 2004
Sales price	58.46	57.75	48.04	54.22	42.21
Royalties	(21.29)	(20.57)	(19.37)	(17.66)	(15.43)
Operating expenses	(10.05)	(10.13)	(7.87)	(9.04)	(7.94)
Transportation costs			(0.10)		(0.10)
Operating netback	27.12	27.05	20.70	27.52	18.74

Distributable Cash, Distributions and Taxability of Distributions

Pengrowth generated $619.7 million ($3.94 per average trust unit outstanding) of distributable cash from 2005 operations, compared to $401.2 million ($3.01 per unit) in 2004. Distributions paid or declared were $446.0 million for 2005 (2004 $363.1 million) and as a percentage of cash generated from operations (payout ratio) represent approximately 72 percent (2004 90 percent).

The Board of Directors may change the amount withheld in the future, depending on a number of factors, including future commodity prices, capital expenditure requirements, and the availability of debt and equity capital. Pursuant to the Royalty Indenture, the Board of Directors can establish a reserve for certain items including up to 20 percent of Gross Revenue to fund future capital expenditures or for the payment of royalty income in any future period.

Cash distributions are comprised of a return of capital portion, which is tax deferred, and return on capital portion which is taxable income. The return of capital portion reduces the cost base of a unitholders trust units for purposes of calculating a capital gain or loss upon ultimate disposition. The following discussion relates to the taxation of Canadian unitholders only. For detailed tax information relating to non-residents, please refer to our website www.pengrowth.com.

Cash distributions are paid to unitholders on the 15th day of the second month following the month of production. Cash distributions paid in the 2005 calendar year totaled $2.78 per trust unit and are 80 percent return on capital (taxable) or $2.22 per trust unit and 20 percent return of capital (tax deferred) or $0.56 per trust unit. Changes in the estimated taxable and deferred portion of the cash distributions are announced quarterly.

There is no standardized measure of distributable cash and therefore distributable cash, as reported by Pengrowth, may not be comparable to similar measures presented by other trusts. In conjunction with the change to Pengrowth s withholding practice, distributable cash as presented below may not be comparable to previous disclosures. The following table provides a reconciliation of distributable cash.

($ thousands, except per trust unit amounts)	Three months ended			Twelve months ended	
	Dec. 31, 2005	Sep. 30, 2005	Dec. 31, 2004	**Dec. 31, 2005**	Dec. 31, 2004
Cash generated from operations	**196,588**	158,976	93,287	**618,070**	404,167
Change in non-cash operating working capital	**(7,993)**	(789)	8,576	**(9,833)**	(1,173)
Change in deferred injectants	**7,411**	892	3,228	**10,265**	746
Change in remediation trust funds	**784**	(272)	32	**(20)**	(917)
Change in deferred charges	**(793)**	2,818	(473)	**1,235**	(1,893)
Other	**(118)**	384	308	**22**	248
Distributable cash	**195,879**	162,009	104,958	**619,739**	401,178
Allocation of Distributable Cash					
Cash withheld	**76,021**	52,156	8,492	**173,762**	38,117
Distributions paid or declared	**119,858**	109,853	96,466	**445,977**	363,061
Distributable cash	**195,879**	162,009	104,958	**619,739**	401,178
Distributable cash per trust unit	**1.23**	1.02	0.77	**3.94**	3.01
Distributions paid or declared per trust unit	**0.75**	0.69	0.69	**2.82**	2.63
Payout ratio(1)	**61%**	69%	103%	**72%**	90%

(1) Payout ratio is calculated as distributions paid or declared divided by cash generated from operations.

At this time, Pengrowth anticipates that approximately 75 to 80 percent of 2006 distributions will be taxable to Canadian residents. This estimate is subject to change depending on a number of factors including, but not limited to, the level of commodity prices, acquisitions, dispositions, and new equity offerings.

Acquisitions and Dispositions

On February 28, 2005, Pengrowth closed the acquisition of an additional 11.89 percent working interest in Swan Hills increasing Pengrowth s total working interest in the unit to 22.34 percent. The purchase price was $87 million, after adjustments from the October 1, 2004 effective date to the closing date.

On April 29, 2005, Pengrowth completed the acquisition of Crispin which held interests in oil and natural gas assets mainly in Alberta. This represented Pengrowth s first acquisition of a publicly traded corporation and was funded through the issuance of Class A and Class B trust units valued at approximately $88 million. Pengrowth also assumed debt of approximately $20 million as part of the acquisition.

During the second half of 2005, Pengrowth received approximately $38 million of proceeds from the sale of non-core oil and natural gas properties with associated production of approximately 600 boe per day.

On May 31, 2004, Pengrowth acquired oil and natural gas assets in Alberta and Saskatchewan from a subsidiary of Murphy Oil Corporation for a purchase price of $550 million prior to adjustments.
On August 12, 2004, Pengrowth acquired an additional 34.35 percent interest in Kaybob Notikewin Unit No. 1 for a purchase price of $20 million, bringing Pengrowth s total working interest in this unit to just below 99 percent.

Capital Expenditures

During 2005, Pengrowth spent $175.7 million on development and optimization activities. The largest expenditures were in Judy Creek ($36.7 million), SOEP ($27.2 million), Princess ($11.1 million), Weyburn ($8.8 million), Prespatou ($7.5 million) and Swan Hills ($7.2 million). Pengrowth does not typically participate in high risk exploration activities and in 2005 most of the capital spent on development was directed towards increasing production, arresting production declines and improving recovery through infill drilling.

($ millions)	Three months ended			Twelve months ended	
	Dec. 31, 2005	Sep. 30, 2005	Dec. 31, 2004	**Dec. 31, 2005**	Dec. 31, 2004
Geological and geophysical		0.2	0.2	**1.4**	0.6
Drilling and completions	**41.1**	29.8	36.2	**130.3**	111.5
Plant and facilities	**10.2**	10.0	17.7	**34.1**	49.0
Land purchases	**8.8**	0.8		**9.9**	
Development capital	**60.1**	40.8	54.1	**175.7**	161.1
Acquisitions				**175.1**	573.0
Total capital expenditures and acquisitions	**60.1**	40.8	54.1	**350.8**	734.1

Pengrowth s planned capital expenditures for maintenance and development opportunities at existing properties are approximately $236 million for 2006 which is the largest capital program in Pengrowth s history. Approximately half of the 2006 spending will be on a 280 gross wells (132 net wells) drilling program. The remainder of the budget will be spent on recompletions and reactivations, development of coalbed methane resources, production enhancements and ongoing maintenance. Pengrowth s 2006 capital program targets the furtherance of Pengrowth s short, medium and long term objectives, reflecting Pengrowth s focus on pursuing a balanced approach to the development of its key assets. While the most significant portion of Pengrowth s 2006 capital program will involve the continued development and maintenance of existing production and properties, a key element of the 2006 program will be further development of mid and longer term plays or projects in coalbed methane, heavy oil and enhanced oil recovery.

Reserves

Pengrowth reported year end Proved plus Probable reserves of 219.4 mmboe compared to 218.6 mmboe at year end 2004. Further details of Pengrowth s 2005 year end reserves are provided on pages 37 to 45 of the annual report.

Working Capital

Working capital declined by $33.7 million from a working capital deficiency of $78.5 million in 2004 to a working capital deficiency of $112.2 million as at December 31, 2005. Most of the working capital decline is attributable to an increase in bank indebtedness, accounts payable and accrued liabilities, distributions payable to unitholders and the current portion of the note payable, offset by an increase in accounts receivable as at December 31, 2005.

Pengrowth frequently operates with a working capital deficiency as a result of the fact that distributions related to two production months of operating income are payable to unitholders at the end of any month, but only one month of production is still receivable. For example, at the end of December, distributions related to November and December production months were payable on January 15 and February 15 respectively. November s production revenue, received on December 25, is temporarily applied against Pengrowth s revolving credit facility until the distribution payment on January 15.

Financial Resources and Liquidity

At year end 2005, Pengrowth had a long term debt to debt-plus-equity at book value ratio of 0.2 and maintained $370 million in committed credit facilities which were reduced by drawings of $35 million and by $17 million in letters of credit outstanding at year end. In addition, Pengrowth maintains a $35 million demand operating line of credit. Pengrowth remains well positioned to fund its 2006 development program and to take advantage of acquisition opportunities as they arise. At December 31, 2005, Pengrowth had $337 million available to draw from its credit facilities.

Long term debt at December 31, 2005 included fixed rate term debt denominated in U.S. dollars which translated to Cdn $232.6 million. Due to the improvement in the Canadian to U.S. dollar exchange rate, an unrealized gain of Cdn $57.6 million has been recorded since the U.S. dollar denominated debt was issued in April of 2003. Long term debt at December 31, 2005 also included fixed rate term debt of £50 million which translated to Cdn$100.5 million. Through a series of hedging transactions, Pengrowth fixed the exchange rate in Canadian dollars for all future interest payments and repayment at maturity.

Pengrowth s long term debt increased by $22.7 million in fiscal 2005 to $368.1 million at December 31, 2005. At the end of 2005 Pengrowth also had a $20 million non-interest bearing note payable to Emera related to the purchase of the SOEP offshore facilities from Emera on December 31, 2003. The terms of this note are provided in Note 7 to the financial statements.

During the year Pengrowth incurred $87 million of new debt to fund the acquisition of an additional interest in Swan Hills and assumed $20 million of bank debt from the acquisition of Crispin. Pengrowth was able to fund this new debt from its existing credit facilities.

Pengrowth anticipates funding its 2006 capital expenditures through a combination of undistributed cash from operations, unused credit facilities and any proceeds from property dispositions.

Financial Leverage and Coverage

	Twelve months ended December 31	
	2005	2004
Cash generated from operations to interest expense (times)	**29**	13
Long term debt to cash generated from operations (times)	**0.6**	0.9
Long term debt to debt plus book equity (%)	**20**	19

Class A and Class B Trust Unit Structure

Maintaining its status as a mutual fund trust under *Income Tax Act* (Canada) is of fundamental importance to the Trust. Generally speaking, in addition to several other requirements, in order for a trust such as Pengrowth to be a mutual fund trust under the *Income Tax Act* it must satisfy one of two tests. The first test is a benefit test that requires that the trust must not be established or maintained primarily for the benefit of non-residents of Canada (which is generally interpreted to mean that the majority of unitholders must be residents of Canada) (the Benefit Test). The second test is a property test that requires that, at all times after February 21, 1990, all or substantially all of the trust s property consist of property other than taxable Canadian property (the Property Exception). Pengrowth is aware that many of its competitors have significantly greater than 50 percent non-resident ownership and are relying on the Property Exception to maintain their mutual fund trust status.

For reasons that may be unique to the Trust, it was not clear that the Trust could rely upon the Property Exception, as a sale and leaseback transaction entered into with the Corporation in 1998 regarding certain facilities at Judy Creek may have resulted in the Trust s taxable Canadian property exceeding the threshold required by the Property Exception. On November 26, 2004, the Trust received a customary form of comfort letter from the Department of Finance (Canada) stating that the Department of Finance will recommend to the Minister of Finance that an amendment be made to the Property Exception that would clarify the Trust s ability to rely upon the Property Exception.

As a result of this uncertainty, the Trust adopted the Class A and Class B trust unit structure, which requires that the Class A trust units constitute not more than 49.75 percent of the outstanding trust units of the Trust and that all of the Class B trust units be held by residents of Canada, to ensure that the Trust would satisfy the Benefit Test. The Trust received an advance tax ruling from the Canada Revenue Agency on July 26, 2004 and an amended ruling on December 1, 2004 that confirmed that the Trust would continue to be a mutual fund trust if the Class A trust units constituted less than the ownership threshold of 49.75 percent by June 1, 2005 and the Trust was a mutual fund trust prior to that date.

As at December 31, 2004, the Class A trust units represented 50.2 percent of the outstanding trust units of the Trust. As a result of a public offering of Class B trust units in December of 2004, the issuance of a majority of Class B trust units in connection with Pengrowth s acquisition of Crispin in 2005 and the issuance of Class B trust units in accordance with the Distribution Reinvestment Program and other Pengrowth incentive plans, the ownership threshold of 49.75 percent for the Class A trust units was achieved prior to June 1, 2005 in accordance with the advance income tax ruling. On December 6, 2004, the Minister of Finance indicated that further discussions and consultations concerning the appropriate tax treatment of non-residents owning resource properties through mutual fund trusts would take place.

At present, Pengrowth is maintaining the Class A and Class B trust unit structure in compliance with the advance income tax ruling. The Board of Directors considers it prudent at this time to continue the Class A and Class B trust unit structure.

The Board of Directors may determine, based upon market circumstances as they exist at that time or other factors, that it is in the best interests of all unitholders to: (a) remove the requirement to comply with the ownership threshold that restricts the Class A trust units to 49.75 percent of the outstanding trust units; (b) remove the residency restrictions pertaining to the holding of Class B trust units; (c) permit a free conversion of Class B trust units to Class A trust units; (d) permit the consolidation of the trust unit capital of the Trust; (e) allow a controlled conversion of Class B trust units to Class A trust units over time to preserve an orderly market; (f) maintain the Class A and Class B trust unit structure until market circumstances become more favorable to both classes of unitholders; or (g) take such other action as the Board of Directors may consider appropriate.

Commitments and Contractual Obligations

($ thousands)	2006	2007	2008	2009	2010	Thereafter	Total
Long term debt [1]					174,450	193,639	368,089
Interest payments on long term debt [2]	17,298	17,298	17,298	17,298	11,564	34,546	115,302
Note payable	20,000						20,000
Operating leases							
Office rent	2,030	2,070	3,096	3,055	3,036	21,529	34,816
Vehicle leases	852	776	604	306	91		2,629
	2,882	2,846	3,700	3,361	3,127	21,529	37,445
Purchase obligations							
Pipeline transportation	43,839	38,197	34,981	29,813	11,748	53,525	212,103
Capital expenditures	33,323	7,098	294				40,715
CO_2 purchases	5,119	4,357	4,198	4,232	4,267	18,728	40,901
	82,281	49,652	39,473	34,045	16,015	72,253	293,719
Remediation trust fund payments	250	250	250	250	250	11,250	12,500
	122,711	70,046	60,721	54,954	205,406	333,217	847,055

(1) Foreign dollar denominated debt due as follows: $150 million U.S. in April 2010,

$50 million U.S. in April 2013 and £50 million in December 2015, translated at the Dec 31, 2005 exchange rate.

(2) Interest payments on foreign denominated debt, calculated based on Dec 31, 2005 foreign exchange rate.

Trust Unit Information
Trust Unit Trading after re-class[1]

	High	Low	Close	Volume (000 s)	Value ($ millions)
TSX PGF.A ($ Cdn)					
2005 1st quarter	**28.29**	**22.15**	**24.03**	**2,049**	**53.3**
2nd quarter	**27.90**	**23.95**	**27.20**	**1,798**	**46.4**
3rd quarter	**30.10**	**26.30**	**29.50**	**2,047**	**58.0**
4th quarter	**29.80**	**23.64**	**27.41**	**1,324**	**35.2**
Year	**30.10**	**22.15**	**27.41**	**7,218**	**192.9**
2004 1st quarter					
2nd quarter					
3rd quarter	24.19	19.10	22.67	1,672	35.5
4th quarter	26.33	20.03	24.93	2,607	58.9
Year	26.33	19.10	24.93	4,279	94.4
TSX PGF.B ($ Cdn)					
2005 1st quarter	**19.90**	**16.10**	**17.05**	**29,219**	**543.7**
2nd quarter	**19.01**	**16.37**	**18.40**	**19,370**	**342.5**
3rd quarter	**21.26**	**18.25**	**20.58**	**22,738**	**441.0**
4th quarter	**23.38**	**17.27**	**22.65**	**19,747**	**411.0**
Year	**23.38**	**16.10**	**22.65**	**91,074**	**1,738.2**
2004 1st quarter					
2nd quarter					
3rd quarter	20.00	18.03	18.87	5,588	105.6
4th quarter	20.04	17.51	18.50	16,007	301.8
Year	20.04	17.51	18.50	21,595	407.4
NYSE PGH ($ U.S.)					
2005 1st quarter	**22.94**	**18.11**	**20.00**	**24,621**	**515.1**
2nd quarter	**22.74**	**19.05**	**22.25**	**16,153**	**335.0**
3rd quarter	**25.75**	**21.55**	**25.42**	**14,502**	**340.3**
4th quarter	**25.56**	**20.00**	**23.53**	**17,808**	**399.7**
Year	**25.75**	**18.11**	**23.53**	**73,084**	**1,590.1**
2004 1st quarter					
2nd quarter					
3rd quarter	18.94	14.40	17.93	21,200	350.4
4th quarter	21.24	15.85	20.82	31,174	574.7
Year	21.24	14.40	20.82	52,374	925.1

(1) July 27, 2004, trust units were re-classified as

Class A or Class B trust units. Class A trust units trade on the New York Stock Exchange (NYSE) under PGH and on the Toronto Stock Exchange (TSX) under PGF.A. Class B trust units trade only on the TSX under PGF.B.

Trust Unit Trading before re-class(1)

	High	Low	Close	Volume (000 s)	Value ($ millions)
TSX PGF.UN ($ Cdn)					
2004 1st quarter	21.25	15.55	17.98	30,620	567.8
2nd quarter	19.15	16.15	18.67	18,145	328.5
3rd quarter	19.75	18.52	19.42	3,554	68.5
4th quarter					
Year	21.25	15.55	19.42	52,319	964.8
NYSE PGH ($ U.S.)	16.60	12.10	13.70	36,899	525.6
2004 1st quarter					
2nd quarter	14.24	11.62	13.98	22,194	295.9
3rd quarter	14.95	13.84	14.64	5,797	84.5
4th quarter					
Year	14.95	11.62	14.64	64,890	906.0

(1) July 27, 2004, trust units were re-classified as Class A or Class B trust units. Class A trust units trade on the New York Stock Exchange (NYSE) under PGH and on the Toronto Stock Exchange (TSX) under PGF.A. Class B trust units trade only on the TSX under PGF.B.

Pengrowth had 159,864,083 trust units outstanding at December 31, 2005, compared to 152,972,555 trust units at December 31, 2004. The weighted average number of trust units during the year was 157,127,181 (2004 133,935,485).

On April 29, 2005, Pengrowth issued 4.2 million trust units to complete the Crispin acquisition. (see Note 4 to the financial statements for further detail).

Summary of Quarterly Results

The following table is a summary of quarterly results for 2005 and 2004. As this table illustrates, production and distributable cash were impacted positively by the Murphy acquisition in the second quarter of 2004.
This table also shows the relatively high commodity prices sustained throughout 2004 and 2005, which have had a positive impact on net income and distributable cash.

	Q1	Q2	Q3	Q4
2005				
Oil and gas sales ($000 s)	**239,913**	**253,189**	**304,484**	**353,923**
Net income ($000 s)	**56,314**	**53,106**	**100,243**	**116,663**
Net income per trust unit ($)	**0.37**	**0.34**	**0.63**	**0.73**
Net income per trust unit diluted ($)	**0.37**	**0.34**	**0.63**	**0.73**
Distributable cash ($000 s)	**127,804**	**134,047**	**162,009**	**195,879**
Actual distributions paid or declared per trust unit ($)	**0.69**	**0.69**	**0.69**	**0.75**
Daily production (boe)	**59,082**	**57,988**	**58,894**	**61,442**
Total production (mboe)	**5,317**	**5,277**	**5,418**	**5,653**
Average realized price ($ per boe)	**44.97**	**47.79**	**56.07**	**62.55**
Operating netback ($ per boe)	**27.70**	**29.26**	**33.94**	**38.81**
2004				
Oil and gas sales ($000 s)[(1)]	168,771	197,284	226,514	223,183
Net income ($000 s)	38,652	32,684	51,271	31,138
Net income per trust unit ($)	0.31	0.24	0.38	0.23
Net income per trust unit diluted ($)	0.31	0.24	0.38	0.23
Distributable cash ($000 s)[(1)]	92,895	99,021	104,304	104,958
Actual distributions paid or declared per trust unit ($)	0.63	0.64	0.67	0.69
Daily production (boe)	45,668	51,451	60,151	57,425
Total production (mboe)	4,156	4,682	5,534	5,283
Average realized price ($ per boe) [(1)]	40.37	41.83	40.90	42.08
Operating netback ($ per boe)	25.71	25.71	22.77	24.31

Selected Annual Information Financial Results

	Twelve months ended December 31		
($ thousands)	**2005**	2004	2003
Oil and gas sales [(1)]	**1,151,510**	815,751	702,732
Net income	**326,326**	153,745	189,297
Net income per trust unit	**2.08**	1.15	1.63
Distributable cash [(1)]	**619,739**	401,178	345,911
Actual distributions paid or declared per trust unit	**2.82**	2.63	2.68
Total assets	**2,391,432**	2,276,534	1,673,718
Long term financial liabilities [(2)]	**381,026**	383,616	294,300
Unitholders equity	**1,475,996**	1,462,211	1,159,433
Number of units outstanding at year end (thousands)	**159,864**	152,973	123,874

(1) Prior years restated to conform to presentation adopted in the current year

(2) Long term debt plus long term portion of note payable and contract liabilities

Business Risks

The amount of distributable cash available to unitholders and the value of Pengrowth Energy Trust units are subject to numerous risk factors. As the trust units allow investors to participate in the net cash flow from Pengrowth s portfolio of producing oil and natural gas properties, the principal risk factors that are associated with the oil and gas business include, but are not limited to, the following influences:

The prices of Pengrowth s products (crude oil, natural gas, and NGLs) fluctuate due to many factors including local and global market supply and demand, weather patterns, pipeline transportation, and political stability.

The marketability of our production depends in part upon the availability, proximity and capacity of gathering systems, pipelines and processing facilities. Operational or economic factors may result in the inability to deliver our products to market.

Geological and operational risks affect the quantity and quality of reserves and the costs of recovering those reserves. Our actual results will vary from our reserve estimates, and those variations could be material.

Government royalties, income taxes, commodity taxes, and other taxes, levies and fees have a significant economic impact on Pengrowth s financial results. Changes to federal and provincial legislation governing such royalties, taxes and fees could have a material impact on Pengrowth s financial results and the value of Pengrowth trust units.

Environmental laws and regulatory initiatives impact Pengrowth financially and operationally. We may incur substantial capital and operating expenses to comply with increasingly complex laws and regulations covering the protection of the environment and human health and safety. In particular, we may be required to incur significant costs to comply with the 1997 Kyoto Protocol to the United Nations Framework Convention on Climate Change.

Pengrowth s oil and gas reserves will be depleted over time and our level of distributable cash and the value of our trust units could be reduced if reserves and production are not replaced. The ability to replace production depends on Pengrowth s success in developing existing reserves, acquiring new reserves and financing this development and acquisition activity within the context of the capital markets.

Increased competition for properties will drive the cost of acquisition up and expected returns from the properties down.

A significant portion of our properties are operated by third parties. If these operators fail to perform their duties properly, or become insolvent, we may experience interruptions in production and revenues from these properties or incur additional liabilities and expenses as a result of the default of these third party operators.

Increased activity within the oil and gas sector can increase the cost of goods and services and make it more difficult to hire and retain professional staff.

Changing interest rates influence borrowing costs and the availability of capital.

Investors interest in the oil and gas sector may change over time which would affect the availability of capital and the value of Pengrowth trust units.

- The value of Class A trust units and Class B trust units, relative to one another, may be influenced by the different markets in which the trust units trade, the restrictions in entitlement of the Class B trust units to Canadian residents and the limitation in the number of Class A trust units beneath an ownership threshold of 49.75 percent of all trust units outstanding.

- Inflation may result in escalating costs which could impact unitholder distributions and the value of Pengrowth trust units.

- Canadian / U.S. exchange rates influence revenues and, to a lesser extent, operating and capital costs.

- The value of Pengrowth trust units is impacted directly by the related tax treatment of the trust units and the trust unit distributions, and indirectly by the tax treatment of alternative equity investments. Changes in Canadian or U.S. tax legislation could adversely affect the value of our trust units.

Pengrowth mitigates some of these risks by:

- Fixing the price on a portion of its future crude oil and natural gas production.

- Fixing the Canadian / U.S. exchange rate through financial hedging contracts or by fixing commodity prices in Canadian dollars.

- Offering competitive incentive-based compensation packages to attract and retain highly qualified and motivated professional staff.

- Adhering to strict investment criteria for acquisitions.

- Acquiring mature production with long life reserves and proven production.

- Performing extensive geological, geophysical, engineering and environmental analysis before committing to capital development projects.

- Geographically diversifying its portfolio.

- Controlling costs to maximize profitability.

- Developing and adhering to policies and practices that protect the environment and meet or exceed the regulations imposed by the government.

- Developing and adhering to safety policies and practices that meet or exceed regulatory standards.

- Ensuring strong third party operators for non-operated properties.

- Carrying insurance to cover physical losses and business interruption.

These factors should not be considered to be exhaustive. Additional risks are outlined in the Annual Information Form (AIF) of the Trust available on SEDAR at www.sedar.com on or before March 31, 2006.

Subsequent Event

On January 12, 2006, Pengrowth announced certain transactions with Monterey under which Pengrowth has sold oil and gas properties for $22 million of cash and eight million shares in Monterey. As at February 27, 2006 Pengrowth holds approximately 34 percent of the common shares of Monterey.

Outlook

Pengrowth will seek to provide attractive long term returns for unitholders. Our business objectives include:

- Operating our properties in a safe and prudent manner in order to protect our employees, the public, the environment and our investment;
- Maintaining a balanced portfolio of oil and gas properties in our key focus areas;
- Growing production and reserves through accretive acquisitions and low risk development drilling;
- Increasing our undeveloped land position;
- Continuing to optimize costs and maximize netbacks;
- The selective disposition of oil and gas properties that do not meet our return objectives;
- Continuing to maintain a stable distribution policy while withholding a portion of distributable cash to fund future capital programs.

At this time, Pengrowth is forecasting average 2006 production of 54,000 to 56,000 boe per day from our existing properties. This estimate incorporates anticipated production additions from our 2006 development program, offset by the impact of divestitures of approximately 1,300 boe per day and expected production declines from normal operations. The above estimate excludes the potential impact of any future acquisitions or divestitures.

Total operating expenses for 2006 are expected to increase to approximately $220 million. This increase is due to the addition of a full-year of operating expenses associated with Pengrowth s increased working interest in Swan Hills and the acquisition of Crispin. Assuming Pengrowth s average production for 2006 as forecast above, Pengrowth currently estimates 2006 per boe operating expenses of approximately $11.00 per boe.

Budgeted capital expenditures for 2006 total approximately $236 million. Approximately half of the budgeted 2006 expenditures is for a 280 gross wells (132 net wells) drilling program, 27 percent are for facilities and maintenance, nine percent are for land and seismic acquisitions, and eight percent for recompletions, workovers, CO_2 pilot and other. Pengrowth s 2006 capital program targets the furtherance of Pengrowth s short, medium and long term objectives, reflecting Pengrowth s focus on pursuing a balanced approach to the development of its key assets. While the most significant portion of Pengrowth s 2006 capital program will involve the continued development and maintenance of existing production and properties, a key element of the 2006 program will be further development of mid and longer term plays or projects in coalbed methane, heavy oil and enhanced recovery.

APPENDIX C
CONSOLIDATED FINANCIAL STATEMENTS OF PENGROWTH ENERGY TRUST INCLUDING NOTE 20 THEREOF WHICH INCLUDES A RECONCILIATION OF THE CONSOLIDATED FINANCIAL STATEMENTS TO UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

Management s Report to Unitholders

Management s Responsibility to the Unitholders

The financial statements are the responsibility of the management of Pengrowth Energy Trust. They have been prepared in accordance with generally accepted accounting principles, using management s best estimates and judgements, where appropriate.

Management is responsible for the reliability and integrity of the financial statements, the notes to the financial statements, and other financial information contained in this report. In the preparation of these statements, estimates are sometimes necessary because a precise determination of certain assets and liabilities is dependent on future events. Management believes such estimates have been based on careful judgements and have been properly reflected in the accompanying financial statements.

Management is also responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board is assisted in exercising its responsibilities through the Audit Committee of the Board, which is composed of four non-management directors. The Committee meets periodically with management and the auditors to satisfy itself that management s responsibilities are properly discharged, to review the financial statements and to recommend approval of the financial statements to the Board.

KPMG LLP, the independent auditors appointed by the unitholders, have audited Pengrowth Energy Trust s consolidated financial statements in accordance with generally accepted auditing standards and provided an independent professional opinion. The auditors have full and unrestricted access to the Audit Committee to discuss their audit and their related findings as to the integrity of the financial reporting process.

(signed)	(signed)
James S. Kinnear Chairman, President and Chief Executive Officer	Christopher G. Webster Chief Financial Officer

February 27, 2006

Auditors Report

TO THE UNITHOLDERS OF PENGROWTH ENERGY TRUST

We have audited the consolidated balance sheets of Pengrowth Energy Trust as at December 31, 2005 and 2004 and the consolidated statements of income and deficit and cash flow for the years then ended. These financial statements are the responsibility of the Trust s management. Our responsibility is to express an opinion on these consolidated 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 Trust as at December 31, 2005 and 2004 and the results of its operations and its cash flow for the years then ended in accordance with Canadian generally accepted accounting principles.

(signed)
Chartered Accountants
Calgary, Canada
February 27, 2006

Consolidated Balance Sheets

(Stated in thousands of dollars)

As at December 31	**2005**	2004
ASSETS		
Current Assets		
Accounts receivable	**$** 127,394	$ 104,228
Inventory		439
	127,394	104,667
Remediation Trust Funds (Note 3)	8,329	8,309
Deferred Charges (Note 11)	4,886	3,651
Goodwill (Note 4)	182,835	170,619
Property, Plant And Equipment and Other Assets (Note 5)	2,067,988	1,989,288
	$ 2,391,432	$2,276,534
LIABILITIES AND UNITHOLDERS EQUITY		
Current Liabilities		
Bank indebtedness	**$** 14,567	$ 4,214
Accounts payable and accrued liabilities	111,493	80,423
Distributions payable to unitholders	79,983	70,456
Due to Pengrowth Management Limited	8,277	7,325
Note payable (Note 7)	20,000	15,000
Current portion of contract liabilities (Note 4)	5,279	5,795
	239,599	183,213
Note Payable (Note 7)		20,000
Contract Liabilities (Note 4)	12,937	18,216
Long Term Debt (Note 8)	368,089	345,400
Asset Retirement Obligations (Note 6)	184,699	171,866
Future Income Taxes (Note 14)	110,112	75,628
Trust Unitholders Equity		
Trust Unitholders capital (Note 10)	2,514,997	2,383,284
Contributed surplus (Note 10)	3,646	1,923
Deficit (Note 9)	(1,042,647)	(922,996)
	1,475,996	1,462,211
Commitments (Note 18)		
Subsequent Event (Note 19)		
	$ 2,391,432	$2,276,534

See accompanying notes to the consolidated financial statements.

Approved on Behalf of Pengrowth Energy Trust by Pengrowth Corporation, as Administrator

(signed)	(signed)
Director	Director

Consolidated Statements of Income and Deficit

(Stated in thousands of dollars) Years ended December 31	**2005**	2004
REVENUES		
Oil and gas sales	**$ 1,151,510**	$ 815,751
Processing and other income	**15,091**	12,390
Royalties, net of incentives	**(213,863)**	(160,351)
	952,738	667,790
Interest and other income	**2,596**	1,770
Net Revenue	**955,334**	669,560
EXPENSES		
Operating	**218,115**	159,742
Transportation	**7,891**	8,274
Amortization of injectants for miscible floods	**24,393**	19,669
Interest	**21,642**	29,924
General and administrative	**30,272**	24,448
Management fee (Note 15)	**15,961**	12,874
Foreign exchange gain (Note 12)	**(6,966)**	(17,300)
Depletion and depreciation	**284,989**	247,332
Accretion (Note 6)	**14,162**	10,642
	610,459	495,605
Income Before Taxes	**344,875**	173,955
Income Tax Expense (Note 14)		
Capital	**6,273**	4,594
Future	**12,276**	15,616
	18,549	20,210
NET INCOME	**$ 326,326**	$ 153,745
Deficit, beginning of year	**(922,996)**	(713,680)
Distributions paid or declared	**(445,977)**	(363,061)
Deficit, End of Year	**$(1,042,647)**	$(922,996)
Net Income Per Trust Unit (Note 16)		
Basic	**$ 2.077**	$ 1.153
Diluted	**$ 2.066**	$ 1.147

See accompanying notes to the consolidated financial statements.

Consolidated Statements of Cash Flow

(Stated in thousands of dollars) Years ended December 31	**2005**	2004
CASH PROVIDED BY (USED FOR):		
Operating		
Net income	**$ 326,326**	$ 153,745
Depletion, depreciation and accretion	**299,151**	257,974
Future income taxes	**12,276**	15,616
Contract liability amortization	**(5,795)**	(4,164)
Amortization of injectants	**24,393**	19,669
Purchase of injectants	**(34,658)**	(20,415)
Expenditures on remediation	**(7,353)**	(4,440)
Unrealized foreign exchange gain (Note 12)	**(7,800)**	(18,900)
Trust unit based compensation (Note 10)	**2,932**	2,264
Deferred charges (Note 11)	**(4,961)**	
Amortization of deferred charges (Note 11)	**3,726**	1,893
Gain on sale of marketable securities		(248)
Changes in non-cash operating working capital (Note 13)	**9,833**	1,173
	618,070	404,167
Financing		
Distributions	**(436,450)**	(344,744)
Change in long term debt, net	**10,030**	105,000
Note payable (Note 7)	**(15,000)**	(10,000)
Proceeds from issue of trust units	**42,544**	509,830
	(398,876)	260,086
Investing		
Expenditures on property acquisitions	**(92,568)**	(572,980)
Expenditures on property, plant and equipment	**(175,693)**	(161,141)
Proceeds on property dispositions	**37,617**	
Change in remediation trust fund	**(20)**	(917)
Purchase of marketable securities		(2,680)
Proceeds from sale of marketable securities		2,928
Change in non-cash investing working capital (Note 13)	**1,117**	2,169
	(229,547)	(732,621)
Change in Cash and Term Deposits	**(10,353)**	(68,368)
Cash and Term Deposits (Bank Indebtedness) at Beginning of Year	**(4,214)**	64,154
Cash and Term Deposits (Bank Indebtedness) at End of Year	**$ (14,567)**	$ (4,214)

See accompanying notes to the consolidated financial statements.

Notes to Consolidated
Financial Statements
YEARS ENDED DECEMBER 31, 2005 AND 2004

(Tabular amounts are stated in thousands of dollars except per unit amounts.)

1. Structure of the Trust

Pengrowth Energy Trust (the Trust) is a closed-end investment trust created under the laws of the Province of Alberta pursuant to a Trust Indenture dated December 2, 1988 (as amended) between Pengrowth Corporation (Corporation) and Computershare Trust Company of Canada (Computershare). Operations commenced on December 30, 1988. The beneficiaries of the Trust are the holders of trust units (the unitholders).

The purpose of the Trust is to directly and indirectly explore for, develop and hold interests in petroleum and natural gas properties, through investments in securities, royalty units, and notes issued by the Corporation. The activities of Corporation and its subsidiaries are financed by issuance of royalty units and interest bearing notes to the Trust and third party debt. The Trust owns approximately 99.99 percent of the royalty units and 91 percent of the common shares of Corporation. The Trust, through the royalty ownership, obtains substantially all the economic benefits of Corporation. Under the terms of the Royalty Indenture, the Corporation is entitled to retain a one percent share of royalty income and all miscellaneous income (the Residual Interest) to the extent this amount exceeds the aggregate of debt service charges, general and administrative expenses, and management fees. In 2005 and 2004, this Residual Interest, as computed, did not result in any income retained by Corporation.

The royalty units and notes of Corporation held by the Trust entitle it to the net income generated by the Corporation and its subsidiaries petroleum and natural gas properties less amounts withheld in accordance with prudent business practices to provide for future Operating Expenses and Reclamation Obligations, as defined in the Royalty Indenture. In addition, unitholders are entitled to receive the net income from other investments that are held directly by the Trust. Pursuant to the Royalty Indenture, the Board of Directors of Corporation can establish a reserve for certain items including up to 20 percent of Gross Revenue to fund future capital expenditures or for the payment of royalty income in any future period.

Pursuant to the Trust Indenture, Trust unitholders are entitled to monthly distributions from interest income on the notes, royalty income under the Royalty Indenture and from other investments held directly by the Trust, less any reserves and certain expenses of the Trust including General and Administrative costs as defined in the Trust Indenture.

The Board of Directors has general authority over the business and affairs of the Corporation and derives its authority in respect to the Trust by virtue of the delegation of powers by the trustee to the Corporation as Administrator in accordance with the Trust Indenture.

Pengrowth Management Limited (the Manager) has responsibility for the management of the business affairs of the Corporation and the administration of the Trust and defers to the Board of Directors on all matters material to the Corporation and the Trust. Corporate Governance practices are consistent with corporations and trusts that do not have a management agreement. The Manager owns nine percent of the common shares of Corporation, and the Manager is controlled by an officer and a director of the Corporation.

2. Significant Accounting Policies

Basis of Presentation

The Trust s consolidated financial statements have been prepared in accordance with Generally Accepted Accounting Principles (GAAP) in Canada and they include the accounts of the Trust, the Corporation and its subsidiaries (collectively referred to as Pengrowth). All inter-entity transactions have been eliminated. These financial statements do not contain the accounts of the Manager.

The Trust owns 91 percent of the shares of Corporation and, through the royalty and notes, obtains substantially all the economic benefits of Corporation. In addition, the unitholders of the Trust have the right to elect the majority of the Board of Directors of Corporation.

Joint Interest Operations

A significant proportion of Pengrowth s petroleum and natural gas development and production activities are conducted with others and accordingly the accounts reflect only Pengrowth s proportionate interest in such activities.

Property, Plant and Equipment

Pengrowth follows the full cost method of accounting for oil and gas properties and facilities whereby all costs of developing and acquiring oil and gas properties are capitalized and depleted on the unit of production method based on proved reserves before royalties as estimated by independent engineers. The fair value of future estimated asset retirement obligations associated with properties and facilities are also capitalized and depleted on the unit of production method. The associated asset retirement obligations on future development capital costs are also included in the cost base subject to depletion. Natural gas production and reserves are converted to equivalent units of crude oil using their relative energy content.

General and administrative costs are not capitalized other than to the extent they are directly related to a successful acquisition, or to the extent of Pengrowth s working interest in capital expenditure programs to which overhead fees can be recovered from partners. Overhead fees are not charged on 100 percent owned projects.

Proceeds from disposals of oil and gas properties and equipment are credited against capitalized costs unless the disposal would alter the rate of depletion and depreciation by more than 20 percent, in which case a gain or loss on disposal is recorded.

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

Repairs and maintenance costs are expensed as incurred.

Goodwill

Goodwill, which represents the excess of the total purchase price over the estimated fair value of the net identifiable assets and liabilities acquired, is not amortized but instead is assessed for impairment annually or as events occur that could result in impairment. Impairment is assessed by determining the fair value of the reporting entity and comparing this fair value to the book value of the reporting entity. If the fair value of the reporting entity is less than the book value, impairment is measured by allocating the fair value of the reporting entity to the identifiable assets and liabilities of the reporting entity as if the reporting entity had been acquired in a business combination for a purchase price equal to its fair value. The excess of the fair value of the reporting entity over the assigned values of the identifiable assets and liabilities is the fair value of the goodwill. Any excess of the book value of goodwill over this implied fair value is the impairment amount. Impairment is charged to earnings in the period in which it occurs.

Goodwill is stated at cost less impairment.

Injectant Costs

Injectants (mostly natural gas and ethane) are used in miscible flood programs to stimulate incremental oil recovery. The cost of hydrocarbon injectants purchased from third parties for miscible flood projects is deferred and amortized over the period of expected future economic benefit which is estimated as 24 to 30 months.

Inventory

Inventories of crude oil, natural gas and natural gas liquids are stated at the lower of average cost and net realizable value.

Asset Retirement Obligations

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

Pengrowth has placed cash in segregated remediation trust accounts to fund certain ARO for the Judy Creek properties, and the Sable Offshore Energy Project (SOEP). Contributions to these remediation trust accounts and expenditures on ARO not funded by the trust accounts are charged against actual cash distributions in the period incurred.

Income Taxes

The Trust is a taxable trust under the Canadian Income Tax Act. As income taxes are the responsibility of the individual unitholders and the Trust distributes all of its taxable income to its unitholders, no provision has been made for income taxes by the Trust in these financial statements.

The Corporation and its subsidiaries follow the tax liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements of the Corporation and its subsidiaries and their respective tax bases, using enacted income tax rates. The effect of a change in income tax rates on future income tax liabilities and assets is recognized in income in the period that the change occurs.

Trust Unit Compensation Plans

Pengrowth has trust unit based compensation plans, which are described in Note 10. Compensation expense associated with trust unit based compensation plans is recognized in income over the vesting period of the plan with a corresponding increase in contributed surplus. The amount of compensation expense and contributed surplus is reduced for options, rights and deferred entitlement trust units (DEU s) that are cancelled prior to vesting. Any consideration received upon the exercise of trust unit based compensation together with the amount of non-cash compensation expense recognized in contributed surplus is recorded as an increase in trust unitholders capital. Compensation expense is based on the estimated fair value of the trust unit based compensation at the date of grant, as further described in Note 10.

Pengrowth does not have any outstanding trust unit compensation plans that call for settlement in cash or other assets. Grants of such items, if any, will be recorded as expenses and liabilities based on the intrinsic value.

Risk Management

Financial instruments are utilized by Pengrowth to manage its exposure to commodity price fluctuations, foreign currency and interest rate exposures. Pengrowth s practice is not to utilize financial instruments for trading or speculative purposes.

Pengrowth formally documents relationships between hedging instruments and hedged items, as well as its risk management objective and strategy for undertaking various hedge transactions. This process includes linking derivatives to specific assets and liabilities on the balance sheet or to specific firm commitments or forecasted transactions. Pengrowth also formally assesses, both at the hedge s inception and on an ongoing basis, whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in fair value or cash flows of hedged items.

Pengrowth uses forward, futures and swap contracts to manage its exposure to commodity price fluctuations. The net receipts or payments arising from these contracts are recognized in income as a component of oil and gas sales during the same period as the corresponding hedged position.

Foreign exchange gains and losses on foreign currency exchange swaps used to hedge U.S. dollar denominated sales are recognized in income as a component of natural gas sales during the same period as the corresponding hedged position.

Foreign exchange swaps were used to fix the foreign exchange rate on the interest and principal of the £50 million ten year senior unsecured notes (see Note 17). Unrealized foreign exchange gains and losses on the debt and related hedge are recorded as the exchange rate changes.

Measurement Uncertainty

The preparation of financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and revenues and expenses for the period then ended.

The amounts recorded for depletion, depreciation, amortization of injectants, goodwill and ARO are based on estimates. The ceiling test calculation is 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 may impact the consolidated financial statements of future periods.

Earnings per unit

In calculating diluted net income per trust unit, Pengrowth follows the treasury stock method to determine the dilutive effect of trust unit based compensation plans and other dilutive instruments. Under the treasury stock method, only in the money dilutive instruments impact the diluted calculations.

Cash and term deposits

Pengrowth considers term deposits with an original maturity of three months or less to be cash equivalents.

Revenue recognition

Revenue from the sale of oil and natural gas is recognized when the product is delivered. Revenue from processing and other miscellaneous sources is recognized upon completion of the relevant service.

Comparative figures

Certain comparative figures have been reclassified to conform to the presentation adopted in the current year.

3. Remediation Trust Funds

Pengrowth is required to make contributions to a remediation trust fund that is used to cover certain ARO of the Judy Creek properties. Pengrowth makes monthly contributions to the fund of $0.10 per boe of production from the Judy Creek properties and an annual lump sum contribution of $250,000.

Every five years Pengrowth must evaluate the assets in the trust fund and the outstanding ARO, and make recommendations to the former owner of the Judy Creek properties as to whether contribution levels should be changed. In 2004 an evaluation was completed with the results of the evaluation determining that current funding levels would remain unchanged until the next evaluation in 2007. Contributions to the Judy Creek remediation trust fund may change based on future evaluations of the fund.

Pengrowth is required, pursuant to various agreements with the SOEP partners, to make contributions to a remediation trust fund that will be used to fund the ARO of the SOEP properties and facilities. Pengrowth makes monthly contributions to the fund of $0.04 per mcf of natural gas production and $0.08 per boe of natural gas liquids production from SOEP.

The following summarizes Pengrowth s trust fund contributions for 2005 and 2004 and Pengrowth s expenditures on ARO not covered by the trust funds:

	2005	2004
Contributions to Judy Creek Remediation Trust Fund	**$ 778**	$ 906
Contributions to SOEP Environmental Restoration Fund	**556**	548
Expenditures related to Judy Creek Remediation Trust Fund	**(1,314)**	(537)
	20	917
Expenditures on ARO not covered by the trust funds	**6,039**	3,903
Expenditures on ARO covered by the trust funds	**1,314**	537
	7,353	4,440
Total trust fund contributions and ARO expenditures not covered by the trust funds	**$ 7,373**	$5,357

4. Acquisitions

Corporate Acquisitions

On April 29, 2005, Pengrowth acquired all of the issued and outstanding shares of Crispin Energy Inc. (Crispin) which held interests in oil and natural gas assets mainly in Alberta. The shares were acquired on the basis of exchanging 0.0725 Class B trust units of the Trust for each share held by Canadian resident shareholders of Crispin and 0.0512 Class A trust units of the Trust for each share held by non-Canadian resident shareholders of Crispin. The average value assigned to each trust unit issued was $20.80 based on the weighted average trading price of the Class A and Class B trust units for a period before and after the acquisition was announced. The Trust issued 3,538,581 Class B trust units and 686,732 Class A trust units valued at $88 million. The transaction was accounted for using the purchase method of accounting with the allocation of the purchase price and consideration as follows:

Allocation of purchase price:	
Working capital	$ 1,655
Property, plant, and equipment	121,729
Goodwill	12,216
Bank debt	(20,459)
Asset retirement obligations	(4,038)
Future income taxes	(22,208)
	$ 88,895
Cost of acquisition:	
Trust units issued	$ 87,960
Acquisition costs	935
	$ 88,895

Property, plant and equipment of $122 million represents the estimated fair value of the assets acquired determined in part by an independent reserve evaluation. Goodwill of $12 million, which is not deductible for tax purposes, was determined based on the excess of the total cost of the acquisition less the value assigned to the identifiable assets and liabilities, including the future income tax liability.

The future income tax liability was determined based on an enacted income tax rate of approximately 34 percent as at April 29, 2005. Results from operations of the acquired assets of Crispin subsequent to April 29, 2005 are included in the consolidated financial statements.

On May 31, 2004, Pengrowth acquired all of the issued and outstanding shares of a company which had interests in oil and natural gas assets in Alberta and Saskatchewan (the Murphy acquisition). The transaction was accounted for using the purchase method of accounting with the allocation of the purchase price and consideration paid as follows:

Allocation of purchase price:	
Working capital	$ 9,310
Property, plant, and equipment	502,924
Goodwill	170,619
Asset retirement obligations	(43,876)
Future income taxes	(60,012)
Contract liabilities	(28,175)
	$550,790
Cost of acquisition:	
Cash and term deposits	$224,700
Acquisition facility	325,000
Acquisition costs	1,090
	$550,790

Property, plant and equipment of $503 million represents the fair value of the assets acquired determined in part by an independent reserve evaluation, net of purchase price adjustments. Goodwill of $171 million, which is not deductible for tax purposes, was determined based on the excess of the total consideration paid less the value assigned to the identifiable assets and liabilities including the future income tax liability.

The future income tax liability was determined based on the enacted income tax rate of approximately 34 percent as at May 31, 2004.

Contract liabilities include a natural gas fixed price sales contract (see Note 17) and firm pipeline demand charge contracts. The fair value of these liabilities was determined on the date of acquisition and is being reduced as the contracts are settled. As at December 31, 2005 a net liability of $12.3 million (2004 $17.9 million) has been recorded for the natural gas fixed price sales contract and $5.9 million (2004 $6.1 million) has been recorded for the firm pipeline demand charge contracts.

Results of operations from the Murphy Acquisition subsequent to May 31, 2004 are included in the consolidated financial statements.

The following unaudited pro forma information provides an indication of what Pengrowth s results of operations might have been had the Murphy Acquisition taken place on January 1 of 2004:

	2004 Proforma (unaudited)	2004 Actual (audited)
Oil and gas sales	**$897,397**	**$ 815,751**
Net income	**$180,101**	**$ 153,745**
Net income per unit:		
Basic	**$ 1.206**	**$ 1.153**
Diluted	**$ 1.201**	**$ 1.147**

Property Acquisitions

In February 2005, Pengrowth acquired an additional 11.89 percent working interest in Swan Hills for a purchase price of $87 million before adjustments. The acquisition increased Pengrowth s working interest in Swan Hills to 22.34 percent.

In August 2004, Pengrowth acquired an additional 34.35 percent working interest in Kaybob Notikewin Unit No.1 for a purchase price of $20 million before adjustments. The acquisition increased Pengrowth s working interest in the Kaybob Notikewin Unit No.1 to approximately 99 percent.

5. Property, Plant and Equipment and Other Assets

	2005	2004
Property, Plant and Equipment		
Property, Plant and Equipment, at cost	**$ 3,340,106**	$ 2,986,681
Accumulated depletion and depreciation	**(1,307,424)**	(1,022,435)
Net book value of property, plant and equipment	**2,032,682**	1,964,246
Other Assets		
Deferred injectant costs	**35,306**	25,042
Net book value of property, plant and equipment and other assets	**$ 2,067,988**	$ 1,989,288

Property, plant and equipment includes $77.3 million (2004 $81.1 million) related to ARO, net of accumulated depletion.

Pengrowth performed a ceiling test calculation at December 31, 2005 to assess the recoverable value of the property, plant and equipment and other assets. The oil and gas future prices are based on the January 1, 2006 commodity price forecast of our independent reserve evaluators. These prices have been adjusted for commodity price differentials specific to Pengrowth. The following table summarizes the benchmark prices used in the ceiling test calculation. Based on these assumptions, the undiscounted value of future net revenues from Pengrowth s proved reserves exceeded the carrying value of property, plant and equipment and other assets at December 31, 2005.

Year	WTI Oil (U.S.$/bbl)	Foreign Exchange Rate (U.S.$/Cdn)	Edmonton Light Crude Oil (Cdn$/bbl)	AECO Gas (Cdn$/mmbtu)
2006	57.00	0.85	66.25	10.60
2007	55.00	0.85	64.00	9.25
2008	51.00	0.85	59.25	8.00
2009	48.00	0.85	55.75	7.50
2010	46.50	0.85	54.00	7.20
2011	45.00	0.85	52.25	6.90
2012	45.00	0.85	52.25	6.90
2013	46.00	0.85	53.25	7.05
2014	46.75	0.85	54.25	7.20
2015	47.75	0.85	55.50	7.40
2016	48.75	0.85	56.50	7.55
Escalate thereafter	2.0% per year		2.0% per year	2.0% per year

6. Asset Retirement Obligations

The total future ARO were estimated by management based on Pengrowth s working interest in wells and facilities, estimated costs to remediate, reclaim and abandon the wells and facilities and the estimated timing of the costs to be incurred in future periods. Pengrowth has estimated the net present value of its ARO to be $185 million as at December 31, 2005 (2004 $172 million), based on a total escalated future liability of $1,041 million (2004 $551 million). These costs are expected to be made over 50 years with the majority of the costs incurred between 2032 and 2054. Pengrowth s credit adjusted risk free rate of eight percent (2004 eight percent) and an inflation rate of 2.0 percent (2004 1.5 percent) were used to calculate the net present value of the ARO.

The following reconciles Pengrowth s ARO:

	2005	2004
Asset retirement obligations, beginning of year	**$171,866**	$102,528
Increase (decrease) in liabilities during the year related to:		
Acquisitions	**6,347**	44,368
Disposals	**(3,844)**	
Additions	**1,972**	2,681
Revisions	**1,549**	16,087
Accretion expense	**14,162**	10,642
Liabilities settled during the year	**(7,353)**	(4,440)
Asset retirement obligations, end of year	**$184,699**	$171,866

7. Note Payable

The note payable is due to Emera Offshore Incorporated, in respect of the acquisition of the SOEP facility in 2003. The note payable is secured by Pengrowth s working interest in SOEP. The note payable is non-interest bearing with the final payment of $20 million due on December 31, 2006.

At December 31, 2005, $0.7 million (2004 $2.0 million) has been recorded as a deferred charge representing the imputed interest on the non-interest bearing note. This amount will be recognized as interest expense over the term of the note.

8. Long Term Debt

	2005	2004
U.S. dollar denominated debt:		
U.S. $150 million senior unsecured notes at 4.93 percent due April 2010	**$174,450**	$180,300
U.S. $50 million senior unsecured notes at 5.47 percent due April 2013	**58,150**	60,100
	232,600	240,400
Pound sterling denominated £50 million unsecured notes at 5.46 percent due December 2015	**100,489**	
Canadian dollar revolving credit borrowings	**35,000**	105,000
	$368,089	$345,400

On April 23, 2003, Pengrowth closed a U.S. $200 million private placement of senior unsecured notes. The notes were offered in two tranches of U.S. $150 million at 4.93 percent due April 2010 and U.S. $50 million at 5.47 percent due in April 2013. The notes contain certain financial maintenance covenants and interest is paid semi-annually. Costs incurred in connection with issuing the notes, in the amount of $2.1 million are being amortized over the term of the notes (see Note 11).

On December 1, 2005 Pengrowth closed a £50 million private placement of senior unsecured notes. In a series of related hedging transactions, Pengrowth fixed the pound sterling to Canadian dollar exchange rate for all the semi-annual interest payments and the principal repayments at maturity. The notes have an effective rate of 5.49 percent after the hedging transactions. The notes contain the same financial maintenance covenants as the U.S. dollar denominated notes. Costs incurred in connection with issuing the notes, in the amount of $0.7 million are being amortized over the term on the notes (see Note 11).

The Corporation has a $370 million revolving unsecured credit facility syndicated among eight financial institutions with an extendible 364 day revolving period and a three year amortization term period. The facilities are currently reduced by outstanding letters of credit in the amount of approximately $17 million. In addition, it has a $35 million demand operating line of credit. Interest payable on amounts drawn is at the prevailing bankers acceptance rates plus stamping fees, lenders prime lending rates, or U.S. LIBOR rates plus applicable margins, depending on the form of borrowing by the Corporation. The margins and stamping fees vary from zero percent to 1.4 percent depending on financial statement ratios and the form of borrowing.

The revolving credit facility will revolve until June 16, 2006, whereupon it may be renewed for a further 364 days, subject to satisfactory review by the lenders, or converted into a term facility. If converted to a term facility, one third of the amount outstanding would be repaid in equal quarterly instalments in each of the first two years with the final one third to be repaid upon maturity of the term period. The Corporation can post, at its option, security suitable to the banks in lieu of the first year s payments. In such an instance, no principal payment would be made to the banks for one year following the date of non-renewal.

The five year schedule of long term debt repayment based on maturity is as follows: 2006 nil, 2007 nil, 2008 nil, 2009 nil, 2010 $174.5 million.

9. Deficit

	2005	2004
Accumulated earnings	**$ 1,053,383**	$ 727,057
Accumulated distributions paid or declared	**(2,096,030)**	(1,650,053)
	$(1,042,647)	$ (922,996)

Pengrowth is obligated by virtue of its Royalty and Trust Indentures to distribute to unitholders a significant portion of its cash flow from operations. Cash flow from operations typically exceeds net income as a result of non cash expenses such as depletion, depreciation and accretion. These non cash expenses result in a deficit being recorded despite Pengrowth distributing less than its cash flow from operations.

10. Trust Units

The total authorized capital of Pengrowth is 500,000,000 trust units.

Total Trust Units:

	Year Ended December 31, 2005		Year Ended December 31, 2004	
Trust Units Issued	**Number of Trust Units**	**Amount**	Number of Trust Units	Amount
Balance, beginning of period	**152,972,555**	**$2,383,284**	123,873,651	$1,872,924
Issued for cash			26,885,000	499,480
Less: issue expenses				(26,287)
Issued for the Crispin acquisition (non-cash) (Note 4)	**4,225,313**	**87,960**		
Issued for cash on exercise of trust unit options and rights	**1,512,211**	**21,818**	1,294,838	20,251
Issued for cash under Distribution Reinvestment Plan (DRIP)	**1,154,004**	**20,726**	918,366	16,386
Trust unit rights incentive plan (non-cash exercised)		**1,209**		530
Royalty units exchanged for trust units			700	
Balance, end of period	**159,864,083**	**$2,514,997**	152,972,555	$2,383,284

Class A Trust Units:

	Year Ended December 31, 2005		For the period from July 27, 2004 to December 31, 2004	
Trust Units Issued	**Number of Trust Units**	**Amount**	Number of Trust Units	Amount
Balance, beginning of period	**76,792,759**	**$1,176,427**		$
	686,732	**19,002**		

Issued for the Crispin acquisition (non-cash) (Note 4)				
Trust units converted	**45,182**	**692**	76,792,759	1,176,427
Balance, end of period	**77,524,673**	**$1,196,121**	76,792,759	$1,176,427

Class B Trust Units:

Trust Units Issued	**Year Ended December 31, 2005**		For the period from July 27, 2004 to December 31, 2004	
	Number of Trust Units	**Amount**	Number of Trust Units	Amount
Balance, beginning of period	**76,106,471**	**$1,205,734**		$
Trust units converted	**(9,824)**	**(151)**	59,000,129	903,854
Issued for cash			15,985,000	298,920
Less: issue expenses				(15,577)
Issued for the Crispin acquisition (non-cash) (Note 4)	**3,538,581**	**68,958**		
Issued for cash on exercise of trust unit options and rights	**1,512,211**	**21,818**	746,864	11,516
Issued for cash under Distribution Reinvestment Plan (DRIP)	**1,154,004**	**20,726**	374,478	6,750
Trust unit rights incentive plan (non-cash exercised)		**1,209**		271
Balance, end of period	**82,301,443**	**$1,318,294**	76,106,471	$1,205,734

Unclassified Trust Units:

Trust Units Issued	**Year Ended December 31, 2005**		Year Ended December 31, 2004	
	Number of Trust Units	**Amount**	Number of Trust Units	Amount
Balance, beginning of year	**73,325**	**$ 1,123**	123,873,651	$ 1,872,924
Issued for cash			10,900,000	200,560
Less: issue expenses				(10,710)
Issued for cash on exercise of trust unit options and rights			547,974	8,735
Issued for cash under Distribution Reinvestment Plan (DRIP)			543,888	9,636
Trust unit rights incentive plan (non-cash exercised)				259
Royalty units exchanged for trust units			700	
Balance, prior to conversion			135,866,213	2,081,404
Converted to Class A or Class B trust units	**(35,358)**	**(541)**	(135,792,888)	(2,080,281)
Balance, end of year	**37,967**	**$ 582**	73,325	$ 1,123

On July 27, 2004 Pengrowth implemented a reclassification of its trust units whereby the existing outstanding trust units were reclassified into Class A or Class B trust units depending on the residency of the unitholder. Of the original trust units, 37,967 are undeclared trust units that have not been classified as Class A or Class B trust units as the unitholders of these trust units have not submitted a declaration of residency certificate.

The Class A trust units and the Class B trust units have the same rights to vote and obtain distributions upon wind-up or dissolution of the Trust. The most significant distinction between the two classes of units is in respect of residency of the persons entitled to hold and trade the Class A trust units and Class B trust units.

Class A trust units are not subject to any residency restriction but are subject to a restriction on the number to be issued such that the total number of issued and outstanding Class A trust units will not exceed 99 percent of the number issued and outstanding Class B trust units after an initial implementation period (the Ownership Threshold). Class A trust units may be converted by a holder at any time into Class B trust units provided that the holder is a resident of Canada and provides a suitable residency declaration. Class A trust units trade on both the Toronto Stock Exchange (TSX) and the New York Stock Exchange (NYSE).

Class B trust units may not be held by non-residents of Canada and trade only on the TSX. Class B trust units may be converted by a holder into Class A trust units, provided that the Ownership Threshold will not be exceeded.

If the number of issued and outstanding Class A trust units exceeds the Ownership Threshold, the Trust may make a public announcement of the contravention and enforce one or several available options to reduce the number of Class A trust units to the Ownership Threshold, as outlined in the Trust Indenture.

If it appears from the securities registers, or if the Board of Directors of Corporation determines, that a person that is a non-resident of Canada holds or beneficially owns any Class B trust units, Pengrowth shall send a notice to the registered holder(s) of the Class B trust units requiring such holder(s) to dispose of the Class B trust units and pending such disposition may suspend all rights of ownership attached to such units, including the rights to receive distributions.

Following the reclassification, the number of outstanding Class A trust units exceeded the Ownership Threshold. On December 1, 2004, Pengrowth received a letter from the Canada Revenue Agency that extended the date by which Pengrowth must comply with the Ownership Threshold to June 1, 2005. Pengrowth complied with the Ownership Threshold on April 29, 2005 and continued to comply with the Ownership Threshold as of February 27, 2006.

Certain provisions exist that could prevent exclusionary offers being made for only one class of trust units in existence at the time of the original offer. In the event that an offer is made for only one class of trust units; in certain circumstances the Ownership Threshold would temporarily cease to apply.

Pursuant to the terms of the Royalty Indenture and the Trust Indenture, there is attached to each royalty unit granted by the Corporation to royalty unitholders other than the Trust the right to exchange such royalty unit for an equivalent number of trust units. Accordingly, Computershare as Trustee has reserved 18,240 trust units for such future conversion.

Distribution Reinvestment Plan

Class B unitholders are eligible to participate in the Distribution Reinvestment Plan (DRIP). DRIP entitles the unitholder to reinvest cash distributions in additional units of the Trust. The trust units under the plan are issued from treasury at a five percent discount to the weighted average closing price of all Class B trust units traded on the TSX for the 20 trading days preceding a distribution payment date. Class A unitholders are not eligible to participate in DRIP. Trust units issued on the exercise of options and rights under Pengrowth s unit based compensation plans are Class B trust units.

Contributed Surplus

	2005	2004
Balance, beginning of year	**$ 1,923**	$ 189
Trust unit rights incentive plan (non-cash expensed)	**1,740**	2,264
Deferred entitlement trust units	**1,192**	
Trust unit rights incentive plan (non-cash exercised)	**(1,209)**	(530)
Balance, end of year	**$ 3,646**	$1,923

Trust Unit Option Plan

Pengrowth has a trust unit option plan under which directors, officers, employees and special consultants of the Corporation and the Manager are eligible to receive options to purchase Class B trust units. No new grants have been issued under the plan since November 2002. Under the terms of the plan, up to ten percent of the issued and outstanding trust units, to a maximum of ten million trust units, may be reserved for option and right grants. The options expire seven years from the date of grant. One third of the options vest on the grant date, one third on the first anniversary of the date of grant, and the remaining third on the second anniversary.

As at December 31, 2005, options to purchase 259,317 Class B trust units were outstanding (2004 845,374) that expire at various dates to June 28, 2009.

Trust Unit Options

	2005		2004	
	Number of Options	**Weighted Average Exercise Price**	Number of Options	Weighted Average Exercise Price
Outstanding at beginning of year	**845,374**	**$ 16.97**	2,014,903	$ 17.47
Exercised	**(558,307)**	**$ 16.74**	(838,789)	$ 16.82
Expired	**(27,750)**	**$ 18.63**	(325,200)	$ 20.44
Cancelled			(5,540)	$ 16.53
Outstanding at year end	**259,317**	**$ 17.28**	845,374	$ 16.97
Exercisable at year end	**259,317**	**$ 17.28**	845,374	$ 16.97

The following table summarizes information about trust unit options outstanding and exercisable at December 31, 2005:

Options Outstanding and Exercisable

Range of Exercise Prices	**Number Outstanding and Exercisable**	**Weighted Average Remaining Contractual Life (years)**	**Weighted Average Exercise Price**
$12.00 to $14.99	30,193	2.9	$ 13.08
$15.00 to $16.99	38,139	2.7	$ 15.05
$17.00 to $17.99	82,772	2.4	$ 17.47
$18.00 to $20.50	108,213	1.9	$ 19.09
$12.00 to $20.50	259,317	2.3	$ 17.28

Trust Unit Rights Incentive Plan

Pengrowth has a Trust Unit Rights Incentive Plan (Rights Incentive Plan), pursuant to which rights to acquire Class B trust units may be granted to the directors, officers, employees, and special consultants of the Corporation and the Manager. Under the Rights Incentive Plan, distributions per trust unit to unitholders in a calendar quarter which represent a return of more than 2.5 percent of the net book value of property, plant and equipment at the beginning of such calendar quarter result, at the discretion of the holder, in a reduction in the exercise price. Total price reductions calculated for 2005 were $1.49 per trust unit right (2004 $1.30 per trust unit right). One third of the rights granted under the Rights Incentive Plan vest on the grant date, one third on the first anniversary date of the grant and the remaining on the second anniversary. The rights have an expiry date of five years from the date of grant.

As at December 31, 2005, rights to purchase 1,441,737 Class B trust units were outstanding (2004 2,011,451) that expire at various dates to November 21, 2010.

Trust Unit Rights

	2005		2004	
	Number of Rights	**Weighted Average Exercise Price**	Number of Rights	Weighted Average Exercise Price
Outstanding at beginning of year	**2,011,451**	**$ 14.23**	1,112,140	$ 12.20
Granted[(1)]	**606,575**	**$ 18.34**	1,409,856	$ 17.35
Exercised	**(953,904)**	**$ 12.81**	(456,049)	$ 13.47
Cancelled	**(222,385)**	**$ 16.19**	(54,496)	$ 14.19
Outstanding at year end	**1,441,737**	**$ 14.85**	2,011,451	$ 14.23
Exercisable at year end	**668,473**	**$ 13.73**	1,037,078	$ 12.48

(1) Weighted average exercise price of rights

granted are
based on the
exercise price at
the date of
grant.

The following table summarizes information about trust unit rights outstanding and exercisable at December 31, 2005:

	Rights Outstanding			Rights Exercisable	
Range of Exercise Prices	Number Outstanding	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price	Number Exercisable	Weighted Average Exercise Price
\$8.97 to \$13.99	199,280	1.9	\$ 9.03	199,280	\$ 9.03
\$14.00 to \$15.99	549,620	3.1	\$ 14.01	223,339	\$ 14.01
\$16.00 to \$17.99	571,505	3.9	\$ 16.89	206,942	\$ 17.04
\$18.00 to \$20.99	121,332	4.8	\$ 18.65	38,912	\$ 18.68
\$8.97 to \$20.99	1,441,737	3.1	\$ 14.85	668,473	\$ 13.73

Fair Value of Unit Based Compensation

Pengrowth records compensation expense on trust unit rights granted on or after January 1, 2003. For trust unit options and rights granted in 2002, Pengrowth has elected to disclose the pro forma effect on net income had compensation expense been recorded using the fair value method. All of the trust unit options and rights issued in 2002 were fully vested prior to 2005, therefore there is no pro forma effect on net income for 2005. The following is the pro forma effect on net income in 2004:

	2004
Net income	\$ 153,745
Compensation expense related to rights incentive options granted in 2002	(1,067)
Pro forma net income	\$ 152,678
Pro forma net income per unit:	
Basic	\$ 1.145
Diluted	\$ 1.139

The fair value of trust unit rights granted in 2005 and 2004 was estimated at 15 percent of the exercise price at the date of grant using a modified Black-Scholes option pricing model with the following assumptions: risk-free rate of 3.9 percent, volatility of 19 percent (2004 22 percent), expected life of five years and adjustments for the estimated distributions and reductions in the exercise price over the life of the trust unit rights.

Long Term Incentive Program

Effective January 1, 2005, the Board of Directors approved a Long Term Incentive Plan. The DEU s issued under the plan fully vest and are converted to Class B trust units on the third anniversary year from the date of grant and will receive deemed distributions prior to the vesting date in the form of additional DEU s. However, the number of DEU s actually issued to each participant at the end of the three year vesting period will be subject to a relative performance test which compares Pengrowth s three year average total return to the three year average total return of a peer group of other energy trusts such that upon vesting, the number of Class B trust units issued from treasury may range from zero to one and one-half times the number of DEU s granted plus accrued DEU s through the deemed reinvestment of distributions.

Compensation expense related to DEU s is based on the fair value of the DEU s at the date of grant. The number of Class B trust units awarded at the end of the vesting period is subject to certain performance conditions. Compensation expense incorporates the estimated fair value of the DEU s at the date of grant and an estimate of the relative performance multiplier. Fluctuations in compensation expense may occur due to changes in estimating the outcome of the performance conditions. An estimate of forfeiture has not been made; rather compensation expense is reduced for actual forfeitures as they occur. Compensation expense is recognized in income over the vesting period with a corresponding increase or decrease to Contributed Surplus. Upon issuance of the Class B trust units at the end of the vesting period, trust unitholders capital is increased and contributed surplus is reduced. For the 12 months ended December 31, 2005, Pengrowth recorded compensation expense of $1.2 million associated with the DEU s. Compensation expense associated with the DEU s was based on the weighted average estimated fair value of $18.32 per DEU.

	Number of DEU s
Outstanding, beginning of period	
Granted	194,229
Cancelled	(26,258)
Deemed DRIP	17,620
Outstanding, end of period	185,591

Trust Unit Award Plan

Effective July 13, 2005, Pengrowth established an incentive plan to reward and retain employees whereby Class B trust units and cash were awarded to eligible employees. Employees received one half of the trust units and cash on or about January 1, 2006 and will receive one half of the trust units and cash on or about July 1, 2006. Any change in the market value of the Class B trust units and reinvested distributions over the vesting period accrues to the eligible employees.

Pengrowth acquired the Class B trust units to be awarded under the plan on the open market for $4.3 million and placed them in a trust account established for the benefit of the eligible employees. The cost to acquire the trust units has been recorded as deferred compensation expense and is being charged to net income on a straight line basis over one year. In addition, the cash portion of the incentive plan of approximately $1.5 million is being accrued on a straight line basis over one year. Any unvested trust units will be sold on the open market. During the six months ended December 31, 2005 $2.9 million has been charged to net income.

Employee Savings Plans

Pengrowth has savings plans whereby Pengrowth will match contributions by qualifying employees of zero to ten percent of their annual basic salary, less any of Pengrowth s contributions to the Group Registered Retirement Savings Plan (Group RRSP), to purchase trust units in the open market. Participants in the Group RRSP can make contributions from one to 13 percent and Pengrowth will match contributions to a maximum of five percent of their annual basic salary. Pengrowth s share of contributions to the Trust Unit Purchase Plan and Group RRSP were $1.5 million in 2005 (2004 $1.3 million) and $0.5 million in 2005 (2004 $0.4 million), respectively.

Trust Unit Margin Purchase Plan

Pengrowth has a plan whereby the employees and certain consultants of Pengrowth and the Manager can purchase trust units and finance up to 75 percent of the purchase price through an investment dealer, subject to certain participation limits and restrictions. Certain officers and directors hold trust units under the Trust Unit Margin Purchase Plan; however, they are prohibited from increasing the number of trust units they can hold under the plan. Participants maintain personal margin accounts with the investment dealer and are responsible for all interest costs and obligations with respect to their margin loans.

Pengrowth has provided a $1 million letter of credit (2004 $5 million) to the investment dealer to guarantee amounts owing with respect to the plan. The amount of the letter of credit may fluctuate depending on the amounts financed pursuant to the plan. At December 31, 2005, 721,334 Class B trust units were deposited under the plan (2004 848,022) with a market value of $16.3 million (2004 $15.7 million) and a corresponding margin loan of $2.7 million (2004 $3.1 million).

The investment dealer has limited the total margin loan available under the plan to the lesser of $15 million or 35 percent of the market value of the units held under the plan. If the market value of the trust units under the plan declines, Pengrowth may be required to make payments or post additional letters of credit to the investment dealer. Any payments to be made by Pengrowth are to be reduced by proceeds of liquidating the individual s trust units held under the plan. The maximum amount Pengrowth may be required to pay at December 31, 2005 was $2.7 million (2004 $3.1 million), the fair value of which is estimated to be a nominal amount.

Redemption Rights
Trust units are redeemable at the option of the holder. The redemption price is equal to the lesser of 95 percent of the market trading price of the Class B trust units traded on the TSX for the ten trading days after the trust units have been surrendered for redemption and the closing market price of the Class B trust units quoted on the TSX on the date the trust units have been surrendered for redemption. Trust units can be redeemed for cash to a maximum of $25,000 per month. Redemptions in excess of the cash limit must be satisfied by way of a distribution in specie of a pro-rata share of royalty units and other assets, excluding facilities, pipelines or other assets associated with oil and natural gas production, which are held by the Trust at the time the trust units are to be redeemed.

11. Deferred Charges

	2005	2004
Imputed interest on note payable (net of accumulated amortization of $2,859, 2004 $1,587)	**$ 748**	$2,020
U.S. debt issue costs (net of accumulated amortization of $816, 2004 $510)	**1,325**	1,631
Deferred compensation expense (net of accumulated amortization of $2,143, 2004 nil)	**2,141**	
U.K. debt issue costs (net of accumulated amortization of $5)	**672**	
	$4,886	$3,651

12. Foreign Exchange Loss (Gain)

	2005	2004
Unrealized foreign exchange gain on translation of U.S. dollar denominated debt	**$(7,800)**	$(18,900)
Realized foreign exchange losses	**834**	1,600
	$(6,966)	$(17,300)

The U.S. dollar denominated debt is translated into Canadian dollars at the exchange rate in effect at the balance sheet date. Foreign exchange gains and losses are included in income.

13. Other Cash Flow Disclosures

Change in Non-Cash Operating Working Capital

Cash provided by (used for):	**2005**	2004
Accounts receivable	**$(21,511)**	$(22,515)
Inventory	**439**	260
Accounts payable and accrued liabilities	**29,953**	17,225
Due to Pengrowth Management Limited	**952**	6,203
	$ 9,833	$ 1,173

Change in Non-Cash Investing Working Capital

Cash provided by:	**2005**	2004
Accounts payable for capital accruals	**$1,117**	$2,169

Cash payments

	2005	2004
Cash payments made for taxes[1]	**$ 6,424**	$ 4,729
Cash payments made for interest	**$21,779**	$28,119

[1] Capital and resource taxes

14. Income Taxes

In 2003, the federal government implemented a reduction in federal corporate income tax rates that is being phased in over a period of five years commencing 2003. The applicable tax rate on resource income will be reduced from 28 percent to 21 percent. Additionally, crown royalties will be an allowable deduction and the resource allowance will be eliminated.

As a result of the changes to the income tax rates, Pengrowth s future tax rate applied to the temporary differences is approximately 34 percent in 2005 (34 percent in 2004) compared to the federal and provincial statutory rate of approximately 38 percent for the 2005 income tax year. The provision for income taxes in the financial statements differs from the result which would have been obtained by applying the combined federal and provincial tax rate to Pengrowth s income before taxes.

	2005	2004
Income before taxes	**$ 344,875**	$173,955
Combined federal and provincial tax rate	**37.6%**	38.6%
Expected income tax	**129,673**	67,147
Net income of the Trust	**(122,698)**	(59,346)
Resource allowance	**(10,985)**	(8,807)
Non-deductible crown charges	**22,756**	16,476
Unrealized foreign exchange gain	**(1,623)**	(3,648)
Attributed Canadian royalty income	**(3,541)**	(3,113)
Effect of proposed tax changes		3,850
Future tax rate difference	**(1,402)**	(1,585)
Change in valuation allowance		3,035
Other	**96**	1,607
Future income taxes	**12,276**	15,616
Capital taxes	**6,273**	4,594
	$ 18,549	$ 20,210

The net future income tax liability is comprised of:

	2005	2004
Future income tax liabilities:		
Property, plant, equipment and other assets	**$114,256**	$79,774
Unrealized foreign exchange gain	**9,689**	8,378
Other	**110**	
	124,055	88,152
Future income tax assets:		
Attributed Canadian royalty income	**(7,819)**	(4,418)
Contract liabilities	**(6,124)**	(8,072)
Other		(34)
	$110,112	$75,628

At December 31, 2005, the petroleum and natural gas properties and facilities owned by the corporate subsidiaries of Pengrowth have an approximate tax basis of $634 million (2004 $607 million) available for future use as deductions from taxable income.

15. Related Party Transactions

The Manager provides certain services pursuant to a management agreement for which Pengrowth was charged $6.9 million (2004 $6.1 million) for performance fees and $9.1 million (2004 $6.8 million) for a management fee. In addition, Pengrowth was charged $0.9 million (2004 $0.8 million) for reimbursement of general and administrative expenses incurred by the Manager pursuant to the management agreement. The law firm controlled by the Vice President and Corporate Secretary charged $0.7 million (2004 $0.8 million) for legal and advisory services provided to Pengrowth. The transactions have been recorded at the exchange amount. Amounts payable to the related parties are unsecured, non-interest bearing and have no set terms of repayment.

16. Amounts Per Trust Unit

The per trust unit amounts for net income are based on the weighted average trust units outstanding for the year. The weighted average trust units outstanding for 2005 were 157,127,181 trust units (2004 133,395,485 trust units). In computing diluted net income per trust unit, 786,577 trust units were added to the weighted average number of trust units outstanding during the year ended December 31, 2005 (2004 611,086) for the dilutive effect of trust unit options, trust unit rights and DEU s. In 2005, 409,557 (2004 741,838) trust unit options and rights were excluded from the diluted net income per unit calculation as their effect is anti-dilutive.

17. Financial Instruments

Interest Rate Risk

Pengrowth has minimal exposure to interest rate changes as approximately 90 percent of Pengrowth s long term debt at December 31, 2005 has fixed interest rates (Note 8).

At December 31, 2005 and 2004, there were no interest rate swaps outstanding.

Foreign Currency Exchange Risk

Pengrowth is exposed to foreign currency fluctuations as crude oil and natural gas prices received are referenced to U.S. dollar denominated prices. Pengrowth has mitigated some of this exchange risk by entering into fixed Canadian dollar crude oil and natural gas price swaps as outlined in the forward and futures contracts section below. Pengrowth is exposed to foreign currency fluctuation on the U.S. denominated notes for both interest and principal payments. Pengrowth entered into a foreign exchange swap in conjunction with issuing £50 million of ten year term notes (Note 8) which fixed the Cdn$ to £ exchange rate on the interest and principal of the £ denominated debt at approximately £0.4976 per Canadian dollar. The estimated fair value of the foreign exchange swap has been determined based on the amount Pengrowth would receive or pay to terminate the contract at year end. At December 31, 2005, the amount Pengrowth would pay to terminate the foreign exchange swap would be approximately $2.2 million.

At December 31, 2004, there were no foreign currency exchange swaps outstanding.

Credit Risk

Pengrowth sells a significant portion of its oil and gas to commodity marketers, and the accounts receivable are subject to normal industry credit risks. The use of financial swap agreements involves a degree of credit risk that Pengrowth manages through its credit policies which are designed to limit eligible counterparties to those with A credit ratings or better.

Forward and Futures Contracts

Pengrowth has a price risk management program whereby the commodity price associated with a portion of its future production is fixed. Pengrowth sells forward a portion of its future production through a combination of fixed price sales contracts with customers and commodity swap agreements with financial counterparties. The forward and futures contracts are subject to market risk from fluctuating commodity prices and exchange rates.

As at December 31, 2005, Pengrowth had fixed the price applicable to future production as follows:

Crude Oil:

Remaining Term	Volume(bbl per day)	Reference Point	Price per bbl
Financial:			
Jan 1, 2006 Dec 31, 2006	4,000	WTI (1)	$64.08 Cdn

Natural Gas:

Remaining Term		**Volume (mmbtu per day)**	**Reference Point**	**Price per mmbtu**
Financial:				
Jan 1, 2006	Mar 31, 2006	2,500	NYMEX (1)	$14.56 Cdn
Jan 1, 2006	Dec 31, 2006	2,500	Transco Z6[(1)]	$10.63 Cdn
Jan 1, 2006	Dec 31, 2006	2,370	AECO	$8.03 Cdn

(1) Associated Cdn$ / U.S.$ foreign exchange rate has been fixed.

The estimated fair value of the financial crude oil and natural gas contracts has been determined based on the amounts Pengrowth would receive or pay to terminate the contracts at year end. At December 31, 2005, the amount Pengrowth would pay to terminate the financial crude oil and natural gas contracts would be $13.0 million and $5.4 million, respectively.

Natural Gas Fixed Price Sales Contract:

Pengrowth assumed a natural gas fixed price sales contract in conjunction with the Murphy acquisition. At December 31, 2005, the amount Pengrowth would pay to terminate the fixed price sales contract would be $35.3 million. Details of the physical fixed price sales contract are provided below:

Remaining Term		**Volume (mmbtu per day)**	**Price per mmbtu (1)**
2006 to 2009			
Jan 1, 2006	Oct 31, 2006	3,886	$2.23 Cdn
Nov 1, 2006	Oct 31, 2007	3,886	$2.29 Cdn
Nov 1, 2007	Oct 31, 2008	3,886	$2.34 Cdn
Nov 1, 2008	April 30, 2009	3,886	$2.40 Cdn

(1) Reference price based on AECO

Fair value of financial instruments

The carrying value of financial instruments included in the balance sheet, other than long term debt, the note payable and remediation trust funds approximate their fair value due to their short maturity. The fair value of the note payable at December 31, 2005 and 2004 approximated its carrying value net of the imputed interest included in deferred charges. The fair value of the other financial instruments are as follows:

	As at December 31, 2005		As at December 31, 2004	
	Fair Value	**Net Book Value**	Fair Value	Net Book Value

Remediation Funds	**$ 9,071**	**$ 8,329**	$ 8,366	$ 8,309
U.S. dollar denominated debt	**220,187**	**232,600**	238,726	240,400
£ denominated debt	**101,257**	**100,489**		

18. Commitments

Pengrowth has future commitments under various agreements for oil and natural gas pipeline transportation, the purchase of carbon dioxide and operating leases. The commitment to purchase carbon dioxide arises as a result of Pengrowth s working interest in the Weyburn CO_2 miscible flood project [(1)]. Capital expenditures arise from authorized expenditures at SOEP.

	2006	2007	2008	2009	2010	Thereafter	Total
Pipeline transportation	$43,839	$38,197	$34,981	$29,813	$11,748	$ 53,525	$212,103
Capital expenditures	33,323	7,098	294				40,715
CO_2 purchases	5,119	4,357	4,198	4,232	4,267	18,728	40,901
Other commitments	3,132	3,096	3,950	3,610	3,377	32,779	49,944
	$85,413	$52,748	$43,423	$37,665	$19,392	$105,032	$343,663

(1) Contract prices for CO_2 are denominated in U.S. dollars and have been translated at the year end foreign exchange rate.

19. Subsequent Event

On January 12, 2006, Pengrowth announced certain transactions with Monterey under which Pengrowth has sold oil and gas properties for $22 million of cash and eight million shares in Monterey. As at February 27, 2006 Pengrowth holds approximately 34 percent of the common shares of Monterey.

20. Reconciliation of Financial Statements to United States Generally Accepted Accounting Principles

The significant differences between Canadian Generally Accepted Accounting Principles (Canadian GAAP) which, in most respects, conforms to generally accepted accounting principles in the United States (U.S. GAAP), as they apply to Pengrowth, are as follows:

(a) As required annually under U.S. GAAP, the carrying value of petroleum and natural gas properties and related facilities, net of future or deferred income taxes, is limited to the present value of after tax future net revenue from proven reserves, discounted at ten percent (based on prices and costs at the balance sheet date), plus the lower of cost and fair value of unproven properties. At December 31, 1998 and 1997 the application of the full cost ceiling test under U.S. GAAP resulted in a write-down of capitalized costs of $328.6 million and $49.8 million, respectively. At December 31, 2005 and 2004, the application of the full cost ceiling test under U.S. GAAP did not result in a write-down of capitalized costs.

    Where the amount of a ceiling test write-down under Canadian GAAP differs from the amount of the write-down under U.S. GAAP, the charge for depletion will differ in subsequent years.

(b) Under U.S. GAAP, interest and other income would not be included as a component of Net Revenue.

(c) Effective January 1, 2003, Pengrowth prospectively adopted U.S. standards relating to recognizing the compensation expense associated with trust unit based compensation plans. Under U.S. GAAP Pengrowth adopted the following:

(i) For trust unit options granted on or after January 1, 2003, the estimated fair value of the options is recognized as an expense over the vesting period. The compensation expense associated with trust unit options granted prior to January 1, 2003 is disclosed on a pro forma basis. As of January 1, 2005 all trust unit options were fully vested, thus there is no pro forma expense disclosed for 2005.
(ii) For trust unit rights granted on or after January 1, 2003, the estimated fair value of the rights, determined using a modified Black-Scholes option pricing model, is recognized as an expense over the vesting period. The compensation expense associated with the rights granted prior to January 1, 2003 is disclosed on a pro forma basis. As of January 1, 2005 all trust unit rights issued before January 1, 2003 are fully vested, thus there is no pro forma expense disclosed for 2005.
The following is the pro forma effect of trust unit options and rights granted prior to January 1, 2003, had the fair value method of accounting been used:

Year ended December 31,	**2004**
Net income (loss) U.S. GAAP, as reported	$180,045
Compensation expense related to rights incentive options granted prior to January 1, 2003	(1,067)
Pro forma net income U.S. GAAP	$178,978
Pro forma net income U.S. GAAP per unit:	
Basic	$ 1.34
Diluted	$ 1.34

(d) Statement of Financial Accounting Standards (SFAS) 130 requires the reporting of comprehensive income in addition to net income. Comprehensive income includes net income plus other comprehensive income; specifically, all changes in equity of a company during a period arising from non-owner sources.

(e) SFAS 133, Accounting for Derivative Instruments and Hedging Activities establishes accounting and reporting standards for derivative instruments and for hedging activities. This statement requires an entity to establish, at the inception of a hedge, the method it will use for assessing the effectiveness of the hedging derivative and the measurement approach for determining the ineffective aspect of the hedge. Those methods must be consistent with the entity s approach to managing risk.

At December 31, 2005, $18.4 million has been recorded as a current liability in respect of the fair value of financial crude oil and natural gas hedges outstanding at year end with a corresponding change in accumulated other comprehensive income. At December 31, 2004, $7.3 million has been recorded as a current asset in respect of the fair value of the financial crude oil and natural gas hedges outstanding at year end with a corresponding change in accumulated other comprehensive income. These amounts will be recognized against crude oil and natural gas sales over the remaining terms of the related hedges.

At December 31, 2005, $0.3 million has been recorded as a current liability with respect to the ineffective portion of crude oil and natural gas hedges outstanding at year end, with a corresponding change in net income. At December 31, 2004, the ineffective portion of crude oil and natural gas hedges outstanding at year end was not significant.

At December 31, 2005, Pengrowth recorded a loss of $2.2 million relating to the foreign currency swap associated with the issuance of the £ denominated debt. As of February 14, 2006, Pengrowth had adequate documentation in place to account for the foreign currency contract as a hedge under U.S. GAAP.

At December 31, 2004, there were no foreign exchange swaps outstanding.

(f) Under U.S. GAAP the Trust s equity is classified as redeemable equity as the Trust units are redeemable at the option of the holder. The redemption price is equal to the lesser of 95 percent of the market trading price of the Class B trust units traded on the TSX for the 10 trading days after the trust units have been surrendered for redemption and the closing market price of the Class B trust units quoted on the TSX on the date the trust units have been surrendered for redemption. Prior to the reclassification of trust units into Class A or Class B trust units, the trust units were redeemable as described above except the redemption price was based on the market trading price of the original trust units. Trust units can be redeemed for cash to a maximum of $25,000 per month. Redemptions in excess of the cash limit must be satisfied by way of a distribution in Specie of a pro-rata share of royalty units and other assets, excluding facilities, pipelines or other assets associated with oil and natural gas production, which are held by the Trust at the time the trust units are to be redeemed.

(g) Under U.S. standards, an entity that is subject to income tax in multiple jurisdictions is required to disclose income tax expense at each jurisdiction. Pengrowth is subject to tax at the federal and provincial level. The portion of income tax expense taxed at the federal level is $12.9 million (2004 $14.8 million). The portion of income tax expense taxed at the provincial level is $5.7 million (2004 $5.4 million).

(h) In December 2004, the FASB issued SFAS 153 which deals with the accounting for the exchanges of non-monetary assets. SFAS 153 is an amendment of APB Opinion 29. APB Opinion 29 requires that exchanges of non-monetary assets should be measured based on the fair value of the assets exchanged. SFAS 153 amends APB Opinion 29 to eliminate the exception from using fair market value for non-monetary exchanges of similar productive assets and introduce a broader exception for exchanges of non-monetary assets that do not have commercial substance. SFAS 153 is effective for non-monetary asset exchanges occurring in fiscal periods beginning after June 15, 2005. Adopting the provisions of SFAS 153 is not expected to impact the U.S. GAAP financial statements.

In December 2004, the FASB issued SFAS 123R which deals with the accounting for transactions in which an entity exchanges its equity instruments for goods or services. SFAS 123R also addresses transactions in which an entity incurs liabilities in exchange for goods or services that are based on the fair value of the entity s equity instruments or that may be settled by the issuance of those equity instruments. SFAS 123R focuses primarily on accounting for transactions in which an entity obtains employee services in share-based payment transactions. SFAS 123R is a revision of SFAS 123. SFAS 123R requires a public entity to measure the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award (with limited exceptions). That cost will be recognized over the period during which an employee is required to provide service in exchange for the award the requisite service period (usually the vesting period). Since January 1, 2004 Pengrowth has recognized the costs of equity instruments issued in exchange for employee services based on the grant-date fair value of the award (Note 2), in accordance with Canadian GAAP. The methodology for determining fair value of equity instruments issued in exchange for employee services prescribed by SFAS 123R differs from that prescribed by Canadian GAAP. SFAS 123R is effective for exchanges in equity instruments in exchanges for goods or services occurring in fiscal years beginning after June 15, 2005. Adopting the provisions of SFAS 123R is not expected to have a material impact on the U.S. GAAP financial statements.

In May 2005 FASB issued SFAS 154 which deals with the accounting for all voluntary changes in accounting principles as well as changes required by accounting pronouncements that do not include specific transition provisions. SFAS 154 requires retrospective application to prior periods financial statements of changes in accounting principle, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. This Statement defines retrospective application as the application of a different accounting principle to prior accounting periods as if that principle had always been used or as the adjustment of previously issued financial statements to reflect a change in the reporting entity. This Statement also redefines restatement as the revising of previously issued financial statements to reflect the correction of an error. SFAS 123R is effective for changes in accounting pronouncements effective in fiscal years beginning after December 15, 2005. Adopting SFAS 154 is not expected to have a material impact on the U.S. GAAP financial statements.

Consolidated Statements of Income

The application of U.S. GAAP would have the following effect on net income as reported:

Stated in thousands of Canadian Dollars, except per unit amounts **Years ended December 31,**	**2005**	2004
Net income for the year, as reported	**$326,326**	$153,745
Adjustments:		
Depletion and depreciation (a)	**24,723**	26,000
Unrealized gain (loss) on ineffective portion of oil and natural gas hedges (e)	**(255)**	300
Realized loss on foreign exchange contract (e)	**(2,204)**	
Net income U.S. GAAP	**$348,590**	$180,045
Other comprehensive income:		
Realized gain on foreign exchange swap (d)(e)		(2,169)
Unrealized hedging gains (loss) (d)(e)	**(25,470)**	21,186
Comprehensive income U.S. GAAP	**$323,120**	$199,062
Net income U.S. GAAP		
Basic	**$ 2.22**	$ 1.35
Diluted	**$ 2.21**	$ 1.34

Consolidated Balance Sheets

The application of U.S. GAAP would have the following effect on the Balance Sheets as reported:

Stated in thousands of Canadian Dollars December 31, 2005	**As Reported**	**Increase (Decrease)**	**U.S. GAAP**
Assets:			
Capital assets (a)	**$2,067,988**	**$(192,219)**	**$1,875,769**
		$(192,219)	
Liabilities			
Accounts payable (e)	**$ 111,493**	**$ 255**	**$ 111,748**
Current portion of unrealized hedging loss (e)		**18,153**	**18,153**
Current portion of unrealized foreign currency contract (e)		**2,204**	**2,204**
Unitholders equity (f):			
Accumulated other comprehensive income (d)(e)	**$**	**$ (18,153)**	**$ (18,153)**
Trust unitholders equity (a)	**1,475,996**	**(194,678)**	**1,281,318**
		$(192,219)	

Stated in thousands of Canadian Dollars December 31, 2004	**As Reported**	**Increase (Decrease)**	**U.S. GAAP**
Assets:			
Current portion of unrealized hedging gain (e)	$	$ 7,317	$ 7,317
Capital assets (a)	1,989,288	(216,942)	1,772,346
		$(209,625)	
Unitholders equity (f):			
Accumulated other comprehensive income (d)(e)	$	$ 7,317	$ 7,317
Trust unitholders equity (a)	1,462,211	(216,942)	1,245,269
		$(209,625)	

Additional disclosures required under U.S. GAAP

The components of accounts receivable are as follows:

As at December 31,	**2005**	2004
Trade	**$103,619**	$ 77,778
Prepaids	**20,230**	15,378
Other	**3,545**	11,072
	$127,394	$104,228

The components of accounts payable and accrued liabilities are as follows:

As at December 31,	**2005**	2004
Accounts payable	**$ 50,756**	$37,588
Accrued liabilities	**60,737**	42,835
	$111,493	$80,423

APPENDIX D
FIVE YEAR REVIEW PENGROWTH ENERGY TRUST CONSOLIDATED FINANCIAL RESULTS (INCLUDED ON PAGES 115 THROUGH 119 OF THE PENGROWTH ENERGY TRUST 2005 ANNUAL REPORT)

Five Year Review
Consolidated Balance Sheets

(Stated in thousands of dollars) As at December 31	**2005**	2004	2003	2002	2001
ASSETS					
Current assets					
Cash and term deposits			64,154	8,292	3,797
Other current assets	**127,394**	104,667	66,269	44,633	30,546
	127,394	104,667	130,423	52,925	34,343
Goodwill	**182,835**	170,619			
Property, plant and equipment	**2,067,988**	1,989,288	1,530,359	1,493,047	1,229,395
Other long term assets	**13,215**	11,960	12,936	6,679	6,470
	2,391,432	2,276,534	1,673,718	1,552,651	1,270,208
LIABILITIES AND UNITHOLDERS EQUITY					
Current liabilities					
Bank indebtedness	**14,567**	4,214			
Other current liabilities	**225,032**	178,999	117,457	89,493	54,089
	239,599	183,213	117,457	89,493	54,089
Long term debt	**368,089**	345,400	259,300	316,501	345,456
Other long term liabilities	**307,748**	285,710	137,528	73,493	42,123
Trust unitholders equity					
Trust unitholders capital	**2,514,997**	2,383,284	1,872,924	1,662,726	1,280,599
Contributed surplus	**3,646**	1,923	189		
Deficit	**(1 ,042,647)**	(922,996)	(713,680)	(589,562)	(452,059)
	1,475,996	1,462,211	1,159,433	1,073,164	828,540
	2,391,432	2,276,534	1,673,718	1,552,651	1,270,208

Five Year Review
Consolidated Statements of Income and Deficit

(Stated in thousands of dollars) Years ended December 31	**2005**	2004	2003	2002	2001
REVENUES					
Oil and gas sales [1]	**1,151,510**	815,751	702,732	490,472	479,845
Processing and other income	**15,091**	12,390	9,726	6,936	7,071
Royalties, net of incentives [1]	**(213,863)**	(160,351)	(126,617)	(88,777)	(81,876)
	952,738	667,790	585,841	408,631	405,040
Interest and other income	**2,596**	1,770	840	274	1,348
Net revenues	**955,334**	669,560	586,681	408,905	406,388
EXPENSES					
Operating	**218,115**	159,742	149,032	129,802	104,943
Transportation	**7,891**	8,274	8,225		
Amortization of injectants for miscible floods	**24,393**	19,669	32,541	44,330	47,448
Interest	**21,642**	29,924	18,153	15,213	18,806
General and administrative	**30,272**	24,448	15,997	10,992	7,467
Management fee	**15,961**	12,874	10,181	6,567	7,120
Foreign exchange loss (gain)	**(6,966)**	(17,300)	(29,911)	182	0
Depletion and depreciation	**284,989**	247,332	185,270	140,775	126,409
Accretion	**14,162**	10,642	6,039	3,566	3,293
	610,459	495,605	395,527	351,427	315,486
Income before taxes	**344,875**	173,955	191,154	57,478	90,902
Income tax expense					
Capital	**6,273**	4,594	1,857	523	2,717
Future	**12,276**	15,616			
	18,549	20,210	1,857	523	2,717
NET INCOME	**326,326**	153,745	189,297	56,955	88,185
Deficit, beginning of year	**(922,996)**	(713,680)	(589,562)	(452,059)	(324,457)
Distributions paid or declared	**(445,977)**	(363,061)	(313,415)	(194,458)	(215,787)
Deficit, end of year	**(1,042,647)**	(922,996)	(713,680)	(589,562)	(452,059)

Net income per trust unit

Basic	**2.08**	1.15	1.63	0.63	1.24
Diluted	**2.07**	1.15	1.63	0.63	1.24

(1) Prior years restated to conform to presentation adopted in current year.

Five Year Review
Consolidated Statements of Cash Flow

(Stated in thousands of dollars) Years ended December 31	**2005**	2004	2003	2002	2001
CASH PROVIDED BY (USED FOR):					
Operating					
Net income	**326,326**	153,745	189,297	56,955	88,185
Depletion and depreciation	**284,989**	247,332	185,270	140,775	126,409
Accretion	**14,162**	10,642	6,039	3,566	3,293
Future income taxes	**12,276**	15,616			
Amortization of injectants	**24,393**	19,669	32,541	44,330	47,448
Purchase of injectants	**(34,658)**	(20,415)	(23,037)	(15,107)	(56,352)
Other non-cash items	**(19,251)**	(23,595)	(33,696)	(1,783)	(1,223)
Changes in non-cash operating working capital	**9,833**	1,173	(9,863)	120	(2,919)
	618,070	404,167	346,551	228,856	204,841
Financing					
Distributions	**(436,450)**	(344,744)	(306,591)	(171,350)	(241,590)
Changes in long term debt and note payable	**(4,970)**	95,000	15,132	(28,955)	58,080
Proceeds from issue of trust units	**42,544**	509,830	210,198	382,127	305,875
	(398,876)	260,086	(81,261)	181,822	122,365
Investing					
Expenditures on property acquisitions	**(92,568)**	(572,980)	(122,964)	(391,761)	(280,058)
Expenditures on property, plant and equipment	**(175,693)**	(161,141)	(85,718)	(55,631)	(74,026)
Other items	**38,714**	1,500	(746)	41,209	26,142
	(229,547)	(732,621)	(209,428)	(406,183)	(327,942)
Change in cash and term deposits	**(10,353)**	(68,368)	55,862	4,495	(736)
Cash and term deposits (bank indebtedness) at beginning of year	**(4,214)**	64,154	8,292	3,797	4,533
Cash and term deposits (bank indebtedness) at year end	**(14,567)**	(4,214)	64,154	8,292	3,797

Five Year Review
Operating Measures

Years ended December 31	**2005**	2004	2003	2002	2001
PRODUCTION					
Crude Oil (bbl per day)	**20,799**	20,817	23,337	19,914	19,726
Heavy Oil (bbl per day)	**5,623**	3,558			
Natural Gas (mcf per day)	**161,056**	144,277	119,842	111,713	91,764
Natural gas liquids (bbl per day)	**6,093**	5,281	5,722	5,252	5,258
Total (boe per day)	**59,357**	53,702	49,033	43,785	40,320
Annual (mmboe)	**21.7**	19.7	17.9	16.0	14.7
% natural gas	**45**	45	41	43	38
Production per weighted average trust unit outstanding (boe)	**0.14**	0.15	0.15	0.18	0.21
BENCHMARK PRICES					
WTI (U.S. $ per bbl)	**$ 56.70**	$ 41.47	$ 30.99	$ 26.08	$ 25.90
NYMEX (U.S. $ per mmbtu)	**$ 8.62**	$ 6.16	$ 5.39	$ 3.22	$ 4.27
AECO (Cdn $ per mcf)	**$ 8.48**	$ 6.79	$ 6.70	$ 4.07	$ 6.30
Currency (U.S. $ per Cdn $)	**$ 0.83**	$ 0.77	$ 0.71	$ 0.64	$ 0.65
AVERAGE REALIZED PRICES					
Oil ($ per bbl)	**$ 58.59**	$ 43.21	$ 40.85	$ 38.06	$ 37.26
Heavy Oil ($ per bbl)	**$ 33.32**	$ 32.45	n/a	n/a	n/a
Natural Gas ($ per mcf)	**$ 8.76**	$ 6.80	$ 6.35	$ 3.85	$ 4.48
Natural gas liquids ($ per bbl)	**$ 54.22**	$ 42.21	$ 35.54	$ 28.11	$ 30.68
Average price per boe (1)	**$ 53.02**	$ 41.33	$ 39.12	$ 30.50	$ 32.47
AVERAGE NETBACK					
Light oil netback ($ per bbl)	**$ 35.01**	$ 24.38	$ 23.40	n/a	n/a
Heavy oil netback ($ per bbl)	**$ 13.50**	$ 17.73	n/a	n/a	n/a
Natural gas netback ($ per mcf)	**$ 5.95**	$ 4.47	$ 3.89	n/a	n/a
NGL netback ($ per bbl)	**$ 27.52**	$ 18.74	$ 13.09	n/a	n/a
Operating netback ($ per boe)	**$ 32.54**	$ 24.51	$ 22.17	$ 14.70	$ 17.25
Property acquisitions ($ millions)	**$ 175.1**	$ 569.7	$ 126.5	$ 389.3	$ 277.1
Capital expenditures ($ millions)	**$ 175.7**	$ 161.1	$ 85.7	$ 55.6	$ 74.0
Reserves (proved plus probable)					
Reserves acquired in the year (mmboe)	**16.7**	47.9	n/a	37.7	48.4
Reserves at year end (mmboe)	**219.4**	218.6	184.4	214.8	210.5
Acquisition cost per boe (1)	**$ 10.49**	$ 11.89	n/a	$ 10.33	$ 5.72
Reserves per year end trust units outstanding	**1.37**	1.43	1.49	1.94	2.56

(1) Prior years restated to conform to presentation adopted in current year.

Five Year Review
Financial Measures

(Stated in thousands of dollars, except per trust unit amounts) Years ended December 31	**2005**	2004	2003	2002	2001
Expenses (per boe)					
Royalties	**$ 9.87**	$ 8.16	$ 7.07	$ 5.56	$ 5.56
Operating	**$ 10.07**	$ 8.13	$ 8.33	$ 8.12	$ 7.13
Transportation	**$ 0.36**	$ 0.42	$ 0.46	$	$
Amortization of injectants for miscible floods	**$ 1.13**	$ 1.00	$ 1.82	$ 2.77	$ 3.22
Interest	**$ 1.00**	$ 1.52	$ 1.01	$ 0.95	$ 1.28
General and administrative	**$ 1.40**	$ 1.24	$ 0.89	$ 0.69	$ 0.51
Management fee	**$ 0.74**	$ 0.66	$ 0.57	$ 0.41	$ 0.48
Depletion and depreciation	**$ 13.15**	$ 12.58	$ 10.35	$ 8.81	$ 8.59
Accretion	**$ 0.65**	$ 0.54	$ 0.34	$ 0.22	$ 0.22
Net income	**$ 326,326**	$ 153,745	$ 189,297	$ 56,955	$ 88,185
Net income per trust unit	**$ 2.08**	$ 1.15	$ 1.63	$ 0.63	$ 1.24
Distributable Cash					
Cash Generated from Operations	**$ 618,070**	$ 404,167	$ 346,551	$ 228,856	$ 204,841
Cash Generated from Operations per trust unit	**$ 3.93**	$ 3.03	$ 2.99	$ 2.55	$ 2.89
Distributable cash [(1)]	**$ 619,739**	$ 401,178	$ 345,911	$ 199,480	$ 215,787
Distributable cash per trust unit [(1)]	**$ 3.94**	$ 3.01	$ 2.98	$ 2.22	$ 3.04
Actual distributions paid or declared	**$ 445,977**	$ 363,061	$ 313,415	$ 194,458	$ 215,787
Actual distributions paid or declared per trust unit	**$ 2.82**	$ 2.63	$ 2.68	$ 2.07	$ 3.01
Payout Ratio (%)	**72**	90	90	85	105
Number of trust units outstanding					
Weighted average	**157,127**	133,395	115,912	89,923	70,911
Total at year end	**159,864**	152,973	123,874	110,562	82,240
Total assets	**$2,391,432**	$2,276,534	$1,673,718	$1,552,651	$1,270,208
Total assets per trust unit	**$ 14.96**	$ 14.88	$ 13.51	$ 14.04	$ 15.45
Long term debt	**$ 368,089**	$ 345,400	$ 259,300	$ 316,501	$ 345,456
Long term debt per trust unit	**$ 2.30**	$ 2.26	$ 2.09	$ 2.86	$ 4.20
Unitholders equity	**$1,475,996**	$1,462,211	$1,159,433	$1,073,164	$ 828,540
Unitholders equity per trust unit	**$ 9.23**	$ 9.56	$ 9.36	$ 9.71	$ 10.07
Net asset value at 10%	**$2,834,663**	$1,708,012	$1,124,433	$1,239,322	$ 914,970
Net asset value per trust unit	**$ 17.73**	$ 11.17	$ 9.08	$ 11.21	$ 11.13
Capitalization highlights					
Net debt (net of working capital)	**$ 480,294**	$ 443,946	$ 281,334	$ 353,069	$ 365,202
Unitholders equity	**$1,475,996**	$1,462,211	$1,159,433	$1,073,164	$ 828,540
Total book capitalization	**$1,956,290**	$1,906,157	$1,440,767	$1,426,233	$1,193,742
Equity Market capitalization	**$3,989,939**	$3,323,770	$2,632,315	$1,628,583	$1,169,454

Enterprise value	**$4,358,028**	$3,669,170	$2,891,615	$1,945,084	$1,514,910
Return on average equity (%)	**22.2**	11.7	17.0	6.0	11.9
Cash flow return on average equity (%)	**30.3**	27.7	28.1	20.5	29.2
Average cost of debt capital (%)[1]	**4.6**	5.1	5.1	4.6	5.2

[1] Prior years restated to conform to presentation adopted in current year.

APPENDIX E
CORPORATE GOVERNANCE (INCLUDED ON PAGES 48 THROUGH 53 OF THE PENGROWTH ENERGY TRUST 2005 ANNUAL REPORT)

Corporate Governance

Board of Directors
From left to right
Back row:
Michael Parrett
Terry Poole
Kirby Hedrick
Seated:
Stan Wong
John Zaozirny
Jim Kinnear
Tom Cumming

Board Of Directors

Thomas A. Cumming, B.A.Sc., P.Eng.

Tom Cumming joined Pengrowth Corporation s Board of Directors in April 2000. He held the position of President and Chief Executive Officer of the Alberta Stock Exchange from 1988 to 1999. His career also includes 25 years with a major Canadian bank both nationally and internationally. He is currently Chairman of Alberta s Electricity Balancing Pool and serves as a Director of the Canadian Investor Protection Fund, the Alberta Capital Market Foundation and Western Lakota Energy Services Inc. He is also a past president of the Calgary Chamber of Commerce.

Kirby L. Hedrick, B.Sc, P.Eng.

Kirby Hedrick joined Pengrowth Corporation s Board of Directors in April 2005. Mr. Hedrick received a Bachelor of Science and Mechanical Engineering degree from the University of Evansville, Indiana in 1975. He completed the Stanford Executive Program in 1997 and the Stanford Corporate Governance Program in 2003. Mr. Hedrick has extensive engineering and senior management experience in the United States and internationally, retiring in 2000 as Executive Vice President, Upstream of Phillips Petroleum. Mr. Hedrick also serves on the board of Noble Energy Inc.

James S. Kinnear, B.Sc., CFA, Chairman, President and Chief Executive Officer,

Mr. Kinnear graduated from the University of Toronto in 1969 with a Bachelor of Science degree and received a Chartered Financial Analyst designation in 1979. In 1982 he founded Pengrowth Management Limited and in 1988 created Pengrowth Energy Trust. Prior to 1982, he worked in the securities sector in Montreal, Toronto and London, England. Mr. Kinnear is currently a Director of the Calgary Chamber of Commerce and a Director of the National Arts Centre Foundation Board. Mr. Kinnear is Chairman of the Pengrowth Rockyview General Hospital Invitational Golf Tournament, a member of the Calgary Health Trust Development Council and a member of the Canadian Council of Chief Executives.

Michael S. Parrett, B.A. Econ., CA

Michael Parrett, appointed to the Board of Directors of Pengrowth Corporation in April 2004, is currently an independent consultant providing advisory service to various public companies in Canada and the United States. Mr. Parrett is a member of the board of Fording Inc. and is serving as a Trustee for Fording Canadian Coal Trust as well as Chairman of Gabriel Resources Limited. He was formerly President of Rio Algom Limited and prior to that Chief Financial Officer of Rio Algom and Falconbridge Limited. He has participated as an instructor, panel member and guest speaker at various mining conferences, as well as the Law Society of Upper Canada, the Insurance Institute of Ontario and the Canadian School of Management.

A. Terence Poole, B.Comm., CA

Terry Poole joined Pengrowth Corporation s Board of Directors in April 2005. Mr. Poole received a Bachelor of Commerce degree from Dalhousie University and holds a Chartered Accountant designation. Mr. Poole brings extensive senior financial management, accounting, capital and debt market experience to Pengrowth. Mr. Poole currently holds the position of Executive Vice President, Corporate Strategy and Development of Nova Chemicals Corporation. Prior to assuming his present position in 2000, Mr. Poole held various senior management positions with Nova and other companies.

Stanley H. Wong, B.Sc., P.Eng.

Stan Wong is President of Carbine Resources Ltd., a private oil and gas producing and engineering consulting company. He is also a Director of Adamant Energy Inc. a private oil and gas exploration and producing company. Mr. Wong was a senior engineer with Hudson s Bay Oil & Gas for ten years and was employed by Total Petroleum for 15 years where he was Chief Engineer and later became Manager of Special Projects.

John B. Zaozirny, Q.C., B.Comm., LL.B., LL.M., Lead Director

John Zaozirny is Counsel to McCarthy Tetrault and Vice Chairman of Canaccord Capital Corporation. He was Minister of Energy and Natural Resources for the Province of Alberta from 1982 to 1986. Mr. Zaozirny currently serves on the board of numerous Canadian and international corporations. He is also a Governor of the Business Council of British Columbia.

Corporate Governance

The Board of Directors, the Manager and senior management consider good corporate governance to be central to the effective and efficient operation of Pengrowth Energy Trust and the Corporation. The Board of Directors has general authority over the business and affairs of the Corporation and derives its authority in respect to Pengrowth Energy Trust by virtue of the delegation of powers by the Trustee to the Corporation as Administrator in accordance with the Trust Indenture. In accordance with the Royalty Indenture, Trust Indenture and Unanimous Shareholder Agreement, the Trust unitholders and Royalty unitholders also empowered the Trustee and the Corporation to delegate authority to the Manager. The Manager derives its authority from the Management Agreement with both the Corporation and Pengrowth Energy Trust. In practice, the Manager defers to the Board of Directors on all matters material to the Corporation and Pengrowth Energy Trust.

The Board of Directors of the Corporation currently has the following standing committees:

1. Audit Committee
2. Corporate Governance Committee
3. Compensation Committee
4. Reserves Committee

Each committee has a Terms of Reference or Charter which sets out the duties and responsibilities of the committee. These duties and responsibilities are reviewed annually and any changes are submitted to the Board of Directors for approval. At the organizational meeting following Pengrowth s Annual General Meeting, committee members are appointed or re-appointed based on the particular skills of each director. Each committee makes regular reports to the entire Board of Directors. The Board of Directors is responsible for nominating any new directors on the recommendation of the corporate governance committee and invitations to join the board are made by the Lead Director.

Audit Committee

The audit committee is comprised of four members of the board: Tom Cumming (Chairman), Michael Parrett, Kirby Hedrick and Terry Poole. All members are considered independent and financially literate for the purpose of the Sarbanes-Oxley Act of 2002 (SOX) rules governing the composition of the audit committee. The committee includes at least one person that would be considered an audit committee financial expert within the meaning of the SOX rules. The primary purposes of this committee are to review with management and the external auditors the Corporation s and Pengrowth Energy Trust s annual audited and interim unaudited financial statements prior to filing or distribution and to monitor the integrity of the company s financial reporting process and systems of internal controls regarding financial, accounting and legal compliance. The committee also monitors the independence and performance of the the Trust s and the Corporation s auditors and provides an avenue of communication among the external auditors, management and the board. The committee s charter is reviewed annually and any changes are then submitted to the Board of Directors for approval. A Whistle Blower Policy is also in place which sets out the procedures for submitting complaints or concerns to the audit committee regarding financial statement disclosures, accounting, internal accounting controls or auditing matters. Members of the committee meet with the auditor independently from members of management. The committee also has a session at the end of each meeting where management and the auditors are excluded.

Corporate Governance Committee

The corporate governance committee is comprised of four members of the board: John Zaozirny (Chairman), Michael Parrett, Tom Cumming and Terry Poole. Each member of this committee is considered to be independent. The primary function of this committee is to assist the board in carrying out its responsibilities by reviewing corporate governance and nomination issues and making recommendations to the board as appropriate. The corporate governance committee acknowledges the formal guidelines relating to corporate governance in Canada as provided for by National Policy 58-101 Disclosure of Corporate Governance Practices and National Policy 58-201 Corporate Governance Guidelines and the overriding objective of promoting appropriate behaviour with respect to all aspects of Pengrowth s business. The committee also provides oversight review of the Corporation s systems for achieving compliance with legal and regulatory requirements. Duties of the committee include such items as bringing to the Board of Directors issues that are necessary for the proper governance of Pengrowth and developing the approach of the Corporation in matters of corporate governance. The committee also assesses and makes recommendations to the Board of Directors on the size of the board, identifying candidates for membership to the board based on a review of qualifications. The committee considers the mandates of committees of the board, selection and rotation of committee members and the chair and makes recommendations to the board. The committee oversees the evaluation of the performance of the board and reports on the results. The directors complete an annual board effectiveness survey on topics such as board responsibility, operations and effectiveness. The committee also monitors the appropriate sharing of duties between Pengrowth Management Limited, the Corporation and Pengrowth Energy Trust and establishes structures and procedures to permit the board to function independently of management and the Manager relying in part upon a Lead Director. In consultation with the Manager, the committee develops a succession plan for officers, other senior management and key employees of the Corporation. Director compensation is also a responsibility of this committee and any changes are recommended to the Board of Directors. The Committee s Terms of Reference are reviewed annually and any changes are recommended to the Board of Directors for approval. The committee reviews policies such as the Corporate Disclosure Policy, the policy in respect to Insider Trading and Self-Dealing, the Code of Business Ethics and the Privacy Policy on an annual basis and recommends to the board any necessary changes. A session where management is excluded is held at the end of each meeting.

Compensation Committee

The compensation committee is comprised of three members of the board: Michael Parrett (Chairman), Tom Cumming and John Zaozirny. Each member of this committee is considered to be independent. The committee s responsibilities include compensation in the annual budget, annual bonus payments, incentive payments and programs. The compensation committee is also responsible for matters pertaining to the Manager. These include reviewing discussions with the Manager with respect to the strategy and objectives for the Corporation and Pengrowth Energy Trust and the performance of the Manager in accordance with the Management Agreement, KPMG Reports on the Manager s compensation, consideration of Assumed Expenses under the Management Agreement and consideration of extension or termination of the Management Agreement. In consultation with the Manager, the committee recommends for approval by the Board of Directors specific compensation guidelines for senior employees, officers and consultants of the Corporation in the form of stock options, cash compensation and bonuses. The committee reviews disclosure of compensation matters in Pengrowth s public disclosure materials. The committee s Terms of Reference sets out its duties and responsibilities and is reviewed on an annual basis with any changes approved by the board. The committee holds a session where management is excluded as part of its meetings.

Reserves Committee

The reserves committee is comprised of two members of the board: Kirby Hedrick (Chairman) and Stan Wong. The committee s responsibilities include reviewing the Corporation s procedures relating to the disclosure of information with respect to oil and gas activities. The committee meets with management and the independent evaluator to review reserves data and the report of the independent evaluator. The committee then presents a report to the Board of Directors and makes a recommendation regarding approval of the reserves data. The Mandate and Terms of Reference of the committee are reviewed annually and changes are brought to the Board of Directors for approval. As part of its mandate, the committee will review any individual change in a property that is over one million boe of total proved reserves and all properties that individually constitute more than five percent of the total reserves.

Board of Directors

The Board of Directors is comprised of seven members and five of those are considered independent. Two members are considered related to the Corporation and/or Pengrowth Energy Trust by virtue of their appointment by the Manager and other factors. The Corporation has appointed a Lead Director who is considered to be independent. A meeting of only the directors, chaired by the Lead Director, is held at the end of each board meeting. The Board of Directors of the Corporation has adopted a Corporate Governance Policy to formalize guidelines pursuant to which the board will fulfill its obligations to the Corporation. The board has adopted a strategic planning process and has approved a strategic plan that will be reviewed and updated on an annual basis. It will also review and approve the annual budget for the Corporation. On recommendations from the compensation committee, the Board of Directors is responsible for making recommendations to the unitholders on the appointment of the Manager or any amendments to the Management Agreement. The board reviews the Corporation s policies on the recommendation of the corporate governance committee such as the Corporate Disclosure Policy as well as other relevant policies such as the policy on authority levels. The Corporation s Code of Business Conduct and Ethics has also been recently updated and all directors, officers and employees are required to sign an acknowledgement confirming they have read and understand the contents.

The Manager

Under the Management Agreement, the Manager is empowered to act as agent for Pengrowth Energy Trust in respect to various matters, to execute documents on behalf of the Trust and to make executive decisions which conform to general policies and general principles previously established by the Trust. The Manager is empowered to undertake on behalf of the Corporation and Pengrowth Energy Trust, subject to the Royalty Indenture, all matters pertaining to the operations of the Corporation. These matters include a requirement to keep the Corporation fully informed with respect to the acquisition, development, operation and disposition of, and other dealings with, the properties held by the Corporation, a review of opportunities to acquire properties, the conduct of negotiations for the acquisition of properties and the operating, administration and retention of consultants, legal and accounting advisors in respect to the foregoing. The Manager is also given broad responsibility for unitholder services in relation to Pengrowth Energy Trust.

The Manager derives its authority from the Management Agreement with both the Corporation and Pengrowth Energy Trust. In practice, the Manager defers to the Board of Directors on all matters material to the Corporation and Pengrowth Energy Trust. The result is the Board and Pengrowth operate in a manner consistent with corporations and trusts that do not have a management agreement.

APPENDIX F
OIL AND GAS PRODUCING ACTIVITIES PREPARED IN ACCORDANCE WITH SFAS NO. 69 DISCLOSURES ABOUT OIL AND GAS PRODUCING ACTIVITIES .

SUPPLEMENTAL INFORMATION OIL AND GAS PRODUCING ACTIVITIES (unaudited)

The following disclosures have been prepared in accordance with SFAS No. 69 Disclosures about Oil and Gas Producing Activities. :

OIL AND GAS RESERVES

Users of this information should be aware that the process of estimating quantities of proved and proved developed crude oil and natural gas reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history, and continual reassessment of the viability of production under varying economic conditions. Consequently, material revisions to existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the significance of the subjective decisions required and variances in available data for various reservoirs make these estimates generally less precise than other estimates presented in connection with financial statement disclosures.

Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Canadian provincial royalties are determined based on a graduated percentage scale which varies with prices and production volumes. Canadian reserves, as presented on a net basis, assume prices and royalty rates in existence at the time the estimates were made, and the Trust s estimate of future production volumes. Future fluctuations in prices, production rates, or changes in political or regulatory environments could cause the Trust s share of future production from Canadian reserves to be materially different from that presented.

Subsequent to December 31, 2005 no major discovery or other favorable or adverse event is believed to have caused a material change in the estimates of proved or proved developed reserves as of that date.

RESULTS OF OPERATIONS FOR PRODUCING ACTIVITIES

The following table sets forth revenue and direct cost information relating to the Trust s oil and gas producing activities for the years ended December 31.

	2005	2004
	(thousands of dollars)	
Revenue		
Sales	$ 952,738	$ 667,790
Deduct		
Production costs	208,140	152,400
Transportation costs	7,891	8,274
Amortization of injectant costs	24,393	19,669
Technical support and other	9,975	7,342
Depletion, depreciation and amortization	260,266	221,332
Results of operations from producing activities	$ 442,073	$ 258,773

1. The costs in this schedule exclude corporate overhead, interest expense and other operating costs which are not directly related to producing activities.

COSTS INCURRED IN OIL AND GAS PROPERTY ACQUISITION, EXPLORATION AND DEVELOPMENT ACTIVITIES

Costs incurred in oil and gas producing activities for the years ended December 31 are as follows:

	2005	2004
	(thousands of dollars)	
Property Acquisition Costs		
Proved	$ 208,424	$ 512,348
Unproved	18,697	12,766
Development Costs	169,314	161,141
Injectant Costs	34,658	20,415
	$ 431,093	$ 706,670

Acquisition costs include costs incurred to purchase, lease, or otherwise acquire oil and gas properties.

Development costs include the costs of drilling and equipping development wells and facilities to extract, treat and gather and store oil and gas.

Injectants (mostly ethane and methane) are used in miscible flood programs to stimulate incremental oil recovery. The cost of injectants purchased from third parties for miscible flood projects is deferred and amortized over the period of expected future economic benefit which is estimated as 24 to 30 months.

General and administrative costs are not capitalized other than to the extent they are directly related to a successful acquisition, or to the extent of the Trust s working interest in exploration or development projects to which overhead fees can be recovered from partners. Overhead fees are not charged on 100% owned projects.

There were no oil and gas property costs not being amortized in any of the years presented.

CAPITALIZED COSTS RELATING TO OIL AND GAS PRODUCING ACTIVITIES

The capitalized costs and related accumulated depreciation, depletion and amortization, including impairments, relating to the Trust s oil and gas exploration, development and producing activities at December 31 consist of:

	2005	2004
	(thousands of dollars)	
Oil and gas properties	$ 3,375,412	$ 3,011,723
Less accumulated depletion, depreciation and amortization	(1,499,643)	(1,239,377)
Net capitalized costs	$ 1,875,769	$ 1,772,346

OIL AND GAS RESERVE INFORMATION

All of the Trust s proved oil, natural gas liquids, and natural gas reserves are located in Canada, primarily in the provinces of Alberta, British Columbia, Saskatchewan and Nova Scotia. The Trust s proved developed and undeveloped reserves after deductions of royalties are summarized below:

	Crude Oil and Natural Gas Liquids MMbbls	**Natural Gas** Bcf
NET PROVED DEVELOPED AND UNDEVELOPED RESERVES AFTER ROYALTIES		
End of year 2003	**77.3**	**271.4**
Revision of previous estimates	1.7	16.0
Purchase of reserves in place	17.0	97.1
Sales of reserves in place		
Discoveries and extensions	0.1	1.8
Production	(8.8)	(42.7)
End of year 2004	**87.3**	**343.6**
Revision of previous estimates	3.1	11.6
Purchase of reserves in place	8.0	15.2
Sales of reserves in place	(1.2)	(3.9)
Discoveries and extensions	0.6	15.6
Production	(9.6)	(48.6)
End of year 2005	**88.2**	**333.5**
NET PROVED DEVELOPED RESERVES AFTER ROYALTIES		
End of year 2003	60.6	219.9
End of year 2004	70.5	305.7
End of year 2005	70.4	309.3

Notes:

1. Net after royalty reserves are the Trust s lessor royalty, overriding royalty, and working interest share of the gross remaining reserves, after deduction of any crown, freehold and overriding royalties. Such royalties are subject to change by legislation or regulation and can also vary depending on production rates, selling prices and timing of initial production.

2. Reserves are the estimated quantities of crude oil, natural gas and related substances anticipated from geological and engineering data to be recoverable from known accumulations, from a given date forward, by known technology, under existing operating conditions and prices in effect at year end.

3. Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

4. Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are reserves that are expected to be recovered from known accumulations where a significant expenditure is required.

STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS RELATING TO PROVED OIL AND GAS RESERVES

The following information has been developed utilizing procedures described by SFAS No. 69 and based on crude oil and natural gas reserve and production volumes estimated by the independent engineering consultants of the Trust. It may be useful for certain comparison purposes, but should not be solely relied upon in evaluating the Trust or its performance. Further, information contained in the following table should not be considered as representative of realistic assessments of future cash flows, nor should the Standardized Measure of Discounted Future Net Cash Flows be viewed as representative of the current value of the Trust s reserves.

The future cash flows presented below are based on sales prices, cost rates, and statutory income tax rates in existence as of the date of the projections. It is expected that material revisions to some estimates of crude oil and natural gas reserves may occur in the future, development and production of the reserves may occur in periods other than those assumed, and actual prices realized and costs incurred may vary significantly from those used.

Management does not rely upon the following information in making investment and operating decisions. Such decisions are based upon a wide range of factors, including estimates of probable as well as proved reserves, and varying price and cost assumptions considered more representative of a range of possible economic conditions that may be anticipated.

The computation of the standardized measure of discounted future net cash flows relating to proved oil and gas reserves at December 31, 2005 was based on the following benchmark prices; Edmonton par crude oil price of $68.27/bbl and AECO natural gas price of $9.71/mcf. The computation of the standardized measure of discounted future net cash flows relating to proved oil and gas reserves at December 31, 2004 was based on the following benchmark prices; Edmonton par crude oil price of $46.54/bbl and AECO natural gas price of $6.79 /mcf.

STANDARDIZED MEASURE OF DISCOUNTED FUTURE CASH FLOW RELATING TO PROVED OIL AND GAS RESERVES

The following table sets forth the standardized measure of discounted future net cash flows from projected production of the Trust s crude oil and natural gas reserves at December 31, for the years presented.

	2005	**2004**
	(millions of dollars)	
Future cash inflows	$ 8,591	$ 5,869
Future costs		
Future production and development costs	(2,892)	(2,494)
Future net cash flows	5,699	3,375
Deduct: 10% annual discount factor	(2,355)	(1,383)
Standardized measure of discounted future net cash flows	$ 3,344	$ 1,992

CHANGES IN STANDARDIZED MEASURE OF DISCOUNTED FUTURE CASH FLOW RELATING TO PROVED OIL AND GAS RESERVES

The following table sets forth the changes in the standardized measure of discounted future net cash flows at December 31, for the years presented.

	2005	**2004** (2)
	(millions of dollars)	
Future discounted net cash flows at beginning of year	$ 1,992	$ 1,604
Sales and transfer, net of production costs	(706)	(480)
Net change in sales and transfer prices, net of production costs	1,450	176
Development costs during the year	169	161
Change in future development costs	(139)	(166)
Changes due to extensions and discoveries	74	5
Changes due to revisions (including infill drilling and improved recovery)	109	58
Accretion of discount	199	160
Sales of reserves in place	(26)	
Purchase of reserves in place	196	459
Changes in timing of future net cash flows and other	26	15
End of Year	$ 3,344	$ 1,992

Notes:

1. The schedules above are calculated using year-end prices, costs, statutory tax rates and existing proved oil and gas reserves. The value of exploration properties and probable reserves, future exploration costs, future changes in oil and gas prices and in production and development costs are excluded.

2. Certain prior year amounts have been restated to conform to presentation adopted in current year.